Direct Testimony and Schedules
Ian R. Benson

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-21-630
Exhibit___(IRB-1)

Transmission

October 25, 2021

Table of Contents

Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Ian Benson. I am the Area Vice President for Transmission Strategy and Planning for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company – Minnesota (NSPM or the Company) and an operating company of Xcel Energy Inc. (Xcel Energy).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have more than 30 years of experience in the utility industry and have served in positions in nuclear generation, retail electric marketing, wholesale power purchases and sales, and transmission. In my current position as the Area Vice President for Transmission Strategy and Planning, my responsibilities include supervising department engineers in planning electric transmission system expansions, recommending specific construction projects to Xcel Energy management and the Midcontinent Independent System Operator, Inc. (MISO), overseeing transmission-related agreements with MISO and other counterparties, and resolving wholesale customer transmission service concerns. My resume is attached as Exhibit___(IRB-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I present and support the Company's capital forecasts and operation and maintenance (O&M) expense requests for the Transmission organization for purposes of determining electric revenue requirements and final rates in this proceeding. I also provide information related to third-party transmission expenses and wholesale transmission revenues and their impact on the Company's revenue requirements. Further, I discuss a pending Federal Energy

Regulatory Commission (FERC) complaint against the MISO transmission owners related to the return on equity (ROE) and its potential impact on our third-party transmission expenses and wholesale revenues. Finally, I report on methods for calculating transmission system line losses as required by the Commission's order in the Company's 2015 electric rate case (Docket No. E002/GR-15-826).

Q. WHAT ARE THE KEY RESPONSIBILITIES AND OBJECTIVES OF THE TRANSMISSION ORGANIZATION?

A. The NSP Companies, NSPM and Northern States Power Company – Wisconsin (NSPW), own, operate, and maintain an integrated transmission system that has facilities in portions of Minnesota, North Dakota, South Dakota, Wisconsin, and the upper peninsula of Michigan (NSP Transmission System).

The Transmission organization is responsible for the planning, construction, operation, and maintenance of these transmission facilities that allow energy to be safely and reliably transported from generating resources (both Company-owned and third-party owned) to the distribution systems that serve customers. The Transmission organization is focused on ensuring that the NSP Transmission System is reliable, resilient, and able to efficiently accommodate an increasingly diverse and dispersed number of generators.

Q. WHAT WORK DOES THE TRANSMISSION ORGANIZATION UNDERTAKE TO ENSURE RELIABILITY OF THE TRANSMISSION GRID?

A. The Transmission organization makes investments that maintain and improve the reliability of the transmission system. An important component of maintaining the reliability of the transmission system is replacing or refurbishing facilities that are in poor condition or have reached the end of their life. During the economic boom and population growth that followed World War II, there was an expansion of the transmission system across the country to accommodate new generators to meet this rapid growth electrical load and to serve new suburban neighborhoods. One example of this is the 345 kV transmission facilities that were constructed in conjunction with the Interstate-494/694 loop in the Twin Cities in the 1960s. As a result, many of our transmission facilities were placed in service more than 50 years ago and, in some cases, these facilities are 70 years old or older. For instance, on the NSP Transmission System, we have more than 500 miles of line that are more than 70 years old, more than 800 miles that are 60 to 69 years old, and over 1,400 miles that are 50-59 years old. While these facilities have performed well for over half a century, many are now reaching the end of their life and must be replaced.

Additionally, recent severe weather incidents, including the derecho storm that hit parts of the Midwest on August 10, 2020 and the California wildfires, have underscored the importance of addressing the condition of aging transmission infrastructure. The Transmission organization has several programs, including its Major Line Rebuild program, which are focused on evaluating the condition and performance of each component of the transmission system. We then prioritize new investments based on this evaluation and make the necessary replacements and upgrades to maintain the reliability of the system.

Q. ARE THERE OTHER FACTORS AND INVESTMENTS THAT IMPACT TRANSMISSION SYSTEM RELIABILITY?

A. Yes. Another part of maintaining the reliability of the system involves making investments to maintain compliance with the mandatory standards set by the North American Electric Reliability Corporation (NERC) and FERC. We are constantly studying our system to determine what additional infrastructure investments are needed as these standards are updated and as customer loads and generation mixes change.

Further, the reliability of our transmission system also depends on the physical security and resiliency of the system. In addition to reliability standards, NERC has issued physical security standards, or Critical Infrastructure Protection (CIP) standards, to protect the transmission system's key physical assets from potential threats and attacks. Transmission also makes investments to improve the physical security of our substations to comply with these CIP standards. These investments include improving the perimeter fencing, installing additional cameras and other monitoring devices, and replacing substation gates.

Q. WHAT WORK DOES THE TRANSMISSION ORGANIZATION UNDERTAKE TO SUPPORT INCREASINGLY DIVERSE AND DISPERSED GENERATION RESOURCES?

A. The Transmission organization makes investments to reliably and cost-effectively accommodate new generation. From 2010-2017, Xcel Energy worked with other utilities in Minnesota as part of the CapX2020 initiative to upgrade and expand the transmission grid to increase access to renewable energy sources and support reliability. In recent years, we have witnessed unprecedented amounts of renewable energy seeking to interconnect to the grid that is requiring new transmission investments. As of September 21, 2021, there was 151 gigawatts of new capacity in the MISO queue associated with 964 individual projects, the vast majority of which were new solar and wind projects. To accommodate some of these new generators, who are seeking to interconnect their projects with the Company's transmission system, the Company will be making increasing investments to facilitate their interconnection over the course of this multi-year rate plan (MYRP).

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. In my Direct Testimony, I will discuss the Transmission organization and the NSP Transmission System. I will also describe the various entities, in addition to the Minnesota Public Utilities Commission (Commission), that regulate the transmission system.

I will explain that the Transmission organization is proposing capital additions for NSPM and NSPW of approximately $412.9 million for 2022, $418.4 million for 2023, and $361.4 million for 2024 to support the objectives I discussed above. These capital additions include the Huntley–Wilmarth 345 kV Project which is currently being recovered in the Transmission Cost Recovery (TCR) Rider but will be moving into base rates with the implementation of final rates in this case. The Huntley–Wilmarth 345 kV Project has capital additions of $3.2 million in 2022. Company witness Mr. Benjamin C. Halama will discuss the TCR Rider cost recovery in greater detail. I will describe Transmission's six capital budget groupings and the importance of these investments in maintaining a safe, reliable, and robust transmission system. I will provide details about the major planned investments and key capital projects that the Transmission organization will place in service during the term of this MYRP.

I will also discuss the Transmission O&M budgets for 2022 to 2024, which are driven by internal labor, contract labor and consulting, fees, and materials. The Transmission O&M budget for 2022 is $31.6 million, $32.2 million in 2023, and $32.8 million in 2024. The average O&M expense budgeted for these three years ($32.2 million) is below the most recent three-year historical average (2018 to 2020) of $35.7 million. I will provide further explanation as to why our O&M budget for each year is reasonable and allows us the ability to perform the work necessary to operate and maintain the transmission system.

Additionally, I will discuss the MISO third-party transmission expenses and wholesale transmission revenues that are budgeted for 2022 to 2024. The third-party transmission expense for 2022 is $95.4 million, 2023 is $96.4 million, and 2024 is $98.2 million. These costs are the result of the NSP Companies serving their native load customers in four other MISO pricing zones and a small load outside of MISO. The wholesale transmission revenues are $103.8 million for 2022, $106.6 million for 2023, and $109.5 million for 2024. This revenue is the result of transmission services and ancillary services provided to other utilities with load in pricing zones where NSP owns transmission assets.

Finally, I report on methods to calculate line losses on the transmission system as required by the Commission's Order in the Company's 2015 electric rate case (Docket No. E002/GR-15-826).

Q. HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- *Section II* – Transmission System Business Unit,

- *Section III* – Capital Investments,
- *Section IV* – O&M Budget,
- *Section V* – Third-Party Transmission Expenses and Wholesale Transmission Revenues, and
- *Section VI* – Transmission System Line Loss Analysis.

II. TRANSMISSION SYSTEM OVERVIEW

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S TRANSMISSION SYSTEM.

A. The NSP Companies (NSPM and NSPW) are vertically integrated electric utilities that own and operate electric transmission facilities in portions of Minnesota, North Dakota, South Dakota, Wisconsin, and the upper peninsula of Michigan. Together, the NSP Companies own an integrated transmission system comprising approximately 8,400 miles of transmission facilities operating at voltages between 34.5 kV and 500 kV, and approximately 548 transmission and distribution substations. The NSP Companies are transmission owning members of MISO. The NSP Transmission System is planned and operated on an integrated basis and has been under the functional control of MISO since it began operations in February 2002. Transmission service over the NSP Transmission System is open access, and transmission service reservations can be requested and approved under the terms of the MISO Tariff.

Q. CAN YOU DESCRIBE THE CUSTOMERS SERVED BY THE NSP TRANSMISSION SYSTEM?

A. The NSP Transmission System serves the following two customer groups: (1) retail native loads in Minnesota, North Dakota, South Dakota, Wisconsin, and

Michigan and (2) the loads of other investor-owned utilities, cooperatives, and municipal load serving entities (LSEs), and wholesale customers. The wholesale customers comprise approximately 20 percent of the total demand on the NSP Transmission System, with the remaining demand composed of retail native load customers. From a transmission planning and transmission service perspective, our retail customers and the wholesale customers require the same level of service, and as a result, the system is planned to serve the needs of each type of customer equally.

Q. OTHER THAN STATE REGULATORY COMMISSIONS, SUCH AS THE MINNESOTA PUBLIC UTILITIES COMMISSION, WHAT OTHER ENTITIES REGULATE THE NSP TRANSMISSION SYSTEM?

A. The NSP Transmission System is regulated primarily by three entities other than state regulatory commissions. The first is FERC. FERC is a federal independent agency that regulates the interstate transmission of electricity, natural gas, and oil. The Energy Policy Act of 2005 gave FERC additional responsibilities. As part of that responsibility related to electric transmission, FERC:

- Regulates the transmission and wholesale sales of electricity in interstate commerce;
- Reviews the siting applications for electric transmission projects under limited circumstances;
- Protects the reliability of the high voltage interstate transmission system through mandatory reliability standards;
- Enforces FERC regulatory requirements through imposition of civil penalties and other means; and

- Administers accounting and financial reporting regulations and conduct of regulated companies.

The second is NERC. NERC is a not-for-profit international regulatory authority whose primary role is to assure the reliability and security of the country's Bulk Electric System (BES). NERC does this by issuing and enforcing reliability standards, which transmission operators, including the Company, are required to comply with; annually assessing seasonal and long-term reliability; monitoring the BES through system awareness; and educating, training, and certifying industry personnel. As the certified Electric Reliability Organization (ERO), NERC is subject to oversight by FERC.

Third is the Midwest Reliability Organization (MRO). MRO is a non-profit organization dedicated to ensuring the reliability and security of the bulk power system in the north-central region of North America, including parts of both the United States and Canada. MRO is one of six regional entities in North America operating under authority from regulators in the United States through a delegation agreement with NERC, and in Canada through arrangements with provincial regulators. The primary purpose of MRO is to ensure compliance with reliability standards and perform regional assessments of the grid's ability to meet the demands for electricity. MRO audits the NSP Companies for compliance with NERC's reliability standards.

Q. PLEASE DESCRIBE MISO AND ITS ROLE WITH RESPECT TO THE NSP TRANSMISSION SYSTEM.

A. MISO is an independent system operator and regional transmission organization providing open-access transmission service, monitoring the high-voltage transmission system, and operating one of the world's largest real-time energy markets. NSPM and NSPW are transmission-owning members of MISO. This means that, although the NSP Companies own and maintain their transmission assets, MISO operates the NSP Transmission System, in conjunction with the transmission systems of the other 52 transmission owners. Furthermore, MISO establishes: (1) the process and rules for wholesale customers to access the NSP Transmission System on a non-discriminatory basis; (2) the annual transmission planning process for expanding or upgrading the regional transmission system, which includes the NSP Transmission System (*i.e.*, MISO Transmission Expansion Plan (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.

III. CAPITAL INVESTMENTS

A. Overview

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss capital budget trends for Transmission from 2018 to 2021 and discuss major planned investments and key capital projects for 2022, 2023, and 2024. I will also provide details regarding how the Transmission business unit develops its annual capital budget and correspondingly identifies and prioritizes capital projects within the confines of the capital budget. Furthermore, I will discuss how Transmission monitors and controls spending on capital projects as they move from approval through construction.

Q. PLEASE MAKE THE OVERALL BUSINESS CASE FOR TRANSMISSION'S CAPITAL PROGRAM.

A. Reliable and efficient electric service for our customers depends on a strong transmission system composed of facilities that are in good working order and that are able accommodate a diverse mix of generators. The capital investments made by the Transmission business unit are necessary to allow the electricity generated by Company-owned and third-party generators to reach our customers. To maintain the health and reliability of the transmission system, the Transmission organization has made and continues to make reasonable investments in maintaining existing facilities and building new transmission infrastructure to replace facilities in poor condition or to meet NERC requirements or to accommodate new generators. These investments ensure the reliable electric service that residential customers and businesses expect, while also supporting a competitive wholesale electricity market that allows access to low-cost generation across the MISO system.

Absent ongoing investments in our transmission system, the reliability and efficiency of this important system would be at risk. The Transmission organization recognizes that the Company's overall budget is limited, and we seek to prioritize projects in a manner that achieves an appropriate balance in maintaining the health and reliability of our transmission system while also making long-term, cost-effective investments for our customers.

Q. GENERALLY SPEAKING, WHAT TYPE OF CAPITAL INVESTMENTS ARE MADE BY THE TRANSMISSION ORGANIZATION?

A. Our capital projects require investments in transmission line components, such as poles, conductors, gang-operated switches, and land rights for transmission line easements. They also include investments in substation components such as transformers, capacitor banks, reactors, circuit breakers, relay and communication equipment, remote terminals, and real property.

Our capital projects fall into two main categories. The first consists of large capital projects that are often multi-year projects. These projects are capital intensive and are aimed at improving the transmission system; upgrading existing facilities to meet NERC compliance requirements and to accommodate new generation; replacing aging facilities; and making improvements to communication infrastructure and physical security.

In addition to these larger capital projects, Transmission also completes many smaller capital projects each year. These smaller projects comprise a majority of the total number of projects that we complete each year, but make up only a minor part of our overall capital budget. Some examples of these smaller projects include replacement of one to two structures or cross-arms due to condition, storm damage, or age.

Q. ARE THERE ANY OTHER UNIQUE FEATURES OF TRANSMISSION'S CAPITAL INVESTMENTS?

A. Yes. Transmission's capital projects often require several years of development and construction before they are placed in-service as capital additions. This is because many of our capital projects require multiple steps, such as transmission study work and planning, route selection, initial design, permitting, final design, land acquisition, site preparation, and then construction. As a result, the Company may have capital expenditures for a particular project that span multiple years, with an in-service date several years after the first expenses are incurred.

Q. HOW DOES TRANSMISSION CATEGORIZE ITS CAPITAL ADDITIONS?

A. Our capital projects fall into six capital budget groupings based on the main purpose of the project. These grouping are:

- <u>Asset Renewal</u>: This category is primarily for managing the health and performance of transmission assets. The main goal is to ensure that critical assets including transmission lines, substations, and other related assets meet reliability and capacity requirements, while minimizing life-cycle costs. This includes planned replacement of aging transmission lines and substation equipment; unplanned replacement of lines or equipment damaged by storms; additions to, or replacement of, aging fleet vehicles and tools that support capital additions; and line relocations due to road projects.
- <u>Reliability Requirement</u>: Reliability projects are constructed to ensure that the transmission system is compliant with all NERC reliability standards. Compliance with NERC reliability standards is mandatory for all users, owners, and operators of the BES. FERC, NERC, and regional reliability entities monitor and enforce compliance. Any entity found non-compliant may be subject to fines of up to $1.3 million per day per violation. The Transmission organization is continually studying the transmission system to assess compliance with NERC standards. These studies analyze the impacts of forecasted load growth, existing and anticipated generation needs, and new generation interconnections to determine whether transmission upgrades are necessary.

- Communication Infrastructure: This category includes the fiber optic and communication network infrastructure build-out on the existing transmission system to improve communication connectivity for all business units. This infrastructure allows the digital transfer of Supervisory Control and Data Acquisition (SCADA) data and teleprotection services. As telecommunication service providers are retiring the existing obsolete analog connections, Xcel Energy will be continuing our efforts to privatize our communication network infrastructure across the NSPM and NSPW service territories. By reducing dependencies on third-party telecommunications and building our own, the transmission system communication infrastructure build-out improves the transmission and distribution system reliability, performance, and cyber security.
- Physical Security and Resiliency: There are two critical aspects to this grouping of projects: physical security and grid resiliency. Physical security addresses physical threats to utility infrastructure, such as transmission lines and substation equipment. Grid resiliency addresses the Company's ability to monitor and recover from incidents occurring on our system to limit disturbances that may leave our service territory exposed to prolonged outages, oftentimes by adding redundancy to our transmission system. This category also includes projects intended to address NERC standards related to security and grid resiliency.
- Interconnection: This category includes projects that the Company is required to construct under the FERC Open Access Transmission Tariff (OATT) to accommodate interconnection requests from generators, transmission lines, and new load.

- Regional Expansion: This category includes major high voltage transmission line projects that are developed through the regional planning process and serve multiple needs including regional and local reliability and renewable energy outlet. Generally, these are multi-year initiatives and the types of projects for which the Company seeks a Certificate of Need and/or Route Permit from the Commission. This category also includes projects necessary to support economic development.

Many of our capital additions serve multiple purposes, but for budgeting purposes, we classify the capital project according to its primary purpose.

B. Transmission Capital Budget Development and Management

Q. HOW DOES TRANSMISSION ESTABLISH A REASONABLE CAPITAL BUDGET FOR A GIVEN YEAR?

A. The annual capital budget for Transmission is based on collaboration between corporate management of the overall Company finances and the business needs that are identified by Transmission. Company witness Ms. Melissa L. Ostrom explains how the Company establishes overall business unit capital spending guidelines and budgets based on financing availability, specific needs of business units, and the overall needs of the Company.

Q. CAN YOU PROVIDE A SUMMARY OF TRANSMISSION'S CAPITAL BUDGETING PROCESS?

A. Transmission employs a "bottom-up" budgeting process to identify the capital projects that we need to complete within a specific year for our business unit. All of our capital projects are executed under our Capital Project Governance

Process. This governance process has policies and procedures in place that enable Transmission to prioritize and balance our budget such that we appropriately allocate funds. Our capital budgeting process includes four main steps:

1. Identification of potential projects,
2. Vetting of potential projects,
3. Prioritization of potential projects, and
4. Rebalancing and reprioritization of projects based on corporate budget requirements.

Q. WHAT IS THE FIRST STEP IN YOUR BUDGETING PROCESS?

A. We begin our budgeting process by identifying and assessing the potential work that is proposed for integration into the current five-year budget period. New projects must satisfy a clearly defined purpose and need. The criteria used to identify and assess projects are based on the six capital budget groupings I discussed earlier. The budgeting process also takes into account existing projects that were previously approved based on the corporate governance approval requirements that Ms. Ostrom describes. The annual budget is a very dynamic process where new project needs and financial requirements are prioritized against existing projects that most often take multiple years from initial budget approval to construction completion and close out.

Q. AFTER THE LIST OF POSSIBLE CAPITAL PROJECTS IS DEVELOPED, WHAT IS THE NEXT STEP IN THE BUDGETING PROCESS?

A. The project originator develops a proposed statement of work for each project, normally consisting of the proposed preliminary scope, project description, need and benefits description, alternatives and proposed option, desired completion date, consequences of not doing the project, and a basic electric circuit diagram.

Multi-disciplinary project teams are then assembled. These project teams have a diverse set of functional skills including financial management, project management, design and engineering, system operations, construction, siting and land rights, scheduling, vegetation management, and planning. The project teams develop a detailed preliminary scope and schedule for the project with supporting documentation. The project team may also prepare high-level cost estimates to assess alternatives and weigh proposed solutions against other alternatives. These estimates help determine the most reasonable electrical and financial solution to meet the identified transmission needs. The preliminary project scope for the preferred solution is entered into Transmission's budgeting and forecast software tool, called TamCasting.

Q. WHAT HAPPENS AFTER THE PRELIMINARY SCOPE IS DEVELOPED?

A. The proposed project is presented for preliminary scope approval at the regular occurring Gate 1 meeting. All projects must pass through this Gate 1 gate before proceeding to the next project phase. At this Gate 1 meeting, the project's preliminary scope is peer reviewed by employees from relevant functional areas of the Transmission organization (including project management, engineering design, Transmission planning, siting and land rights, construction, and operations). The objective of this meeting is to review and challenge the project need and the proposed preliminary scope while looking for fatal flaws or better solutions. Project alternatives are reviewed to determine whether the proposed solution is the most cost-effective and provides the most long-term value for our customers.

Approval at the Gate 1 meeting allows the project to pass through the Gate 1 gate to the next step in the process. Projects not approved at the Gate 1 meeting are either cancelled or returned to the project origination phase for further need and preliminary scope development based on peer review feedback at the Gate 1 meeting. The project may be re-presented at a future Gate 1 meeting for approval.

Q. IF A PROJECT IS APPROVED AT A GATE 1 MEETING, WHAT IS THE NEXT STEP?

A. The project proceeds to the budget estimate package phase. Based on the Gate 1 approved preliminary scope, the project manager coordinates the development of a budget estimate by reviewing the project deliverables with the project team, identifying and documenting routing and design assumptions, conducting field visits, and collecting estimates generated by engineering, siting and land rights, construction, and vegetation management. In special circumstances, pre-construction work orders are generated for planning and development costs—such orders require immediate, out-of-cycle budget approval. The project group also begins to develop an outage plan, a project-specific safety plan and site security plan, and prepares a preliminary risk register. The project team then assembles the budget estimate package and presents it for approval as part of the annual budget process. This is referred to as the "Budget Approval" phase.

Q. WHAT ACTIVITIES TAKE PLACE IN THE BUDGET APPROVAL PHASE?

A. The Budget Approval phase involves the creation of Transmission's annual budget and schedule for capital projects. This annual budget aligns with the budgeting and budget governance process that Ms. Ostrom addresses in her testimony. Each business unit, including Transmission, works closely with corporate financial performance and reporting to develop capital budgets.

Q. WHAT IS THE FIRST STEP IN THE BUDGET APPROVAL PHASE?

A. The first activity for Transmission in the Budget Approval phase involves the project managers refreshing the cost estimates for previously approved projects. Project managers then enter new proposed project attributes, proposed monthly cash flows, and in-service dates into TamCasting.

Q. AFTER ALL POSSIBLE CAPITAL PROJECTS ARE PLACED IN TAMCASTING, WHAT IS THE NEXT STEP?

A. Our directors and managers, along with other key employees review all possible projects that are entered into TamCasting and represent our proposed budget to determine which should be implemented and included in the Transmission budget. As many of our Reliability Requirement and Regional Expansion projects are multi-year projects, once these projects have commenced, it is difficult to halt or defund these projects in subsequent budget years. We do, however, examine all capital expenditures for a given year to determine whether they are necessary to carry out the final execution of those projects. As a result, these projects often receive higher priority in our budgeting process as they move forward toward completion. Similarly, given our MISO Tariff obligations, we have little latitude to deny specific Interconnection projects from being included in our budget.

After we determine the portion of our budget that is committed to these projects, we examine our remaining budget and determine how to prioritize the remaining proposed projects and previously planned projects. We prioritize those projects based on the risk and urgency of a particular project. After a series of meetings to discuss all of the potential projects and the appropriate prioritization given funding availability, the result is an initial capital budget for Transmission.

Q. AFTER THE INITIAL BUDGET IS DETERMINED, WHAT IS THE NEXT STEP?

A. Transmission's proposed capital budget then moves through the corporate budgeting process discussed by Ms. Ostrom. Based on the corporate budgeting process, a higher or lower percentage of the Company's overall budget may be allocated to Transmission depending on the priority of needs at the Company level. Once the corporate budgeting process is complete, Transmission may be able to maintain its capital budget as proposed or it may need to adjust based on the thresholds established at a corporate level.

Q. WHAT HAPPENS IF TRANSMISSION DOES NOT RECEIVE ALL OF ITS REQUESTED FUNDING?

A. The capital projects that Transmission identifies as necessary in a particular year often exceed the budget thresholds established at a corporate level. When this occurs, our directors and managers reexamine our budget and reprioritize our capital projects based on the new thresholds. During the reprioritization process, we carefully evaluate all of the system risks associated with each of these budget reduction scenarios and reevaluate all mitigation plans that may mean a suboptimal operation of the transmission system but ensure our compliance with all mandated system reliability standards.

Q. DOES THIS BUDGETING PROCESS ENSURE THAT TRANSMISSION'S CAPITAL ADDITIONS ARE REASONABLE AND NECESSARY IN EACH YEAR OF THIS MYRP?

A. Yes. This budgeting process results in a reasonable budget that is representative of the capital investments needed to maintain the reliability of the transmission system used to provide electric service to our customers, provide necessary upgrades to the regional transmission system, comply with NERC reliability requirements and other policy drivers, meet system capacity needs, and ensure the health of existing assets.

Q. PLEASE EXPLAIN THE PROCESS YOU FOLLOW TO MANAGE CAPITAL EXPENDITURES AFTER BUDGET APPROVAL.

A. From a financial perspective, capital projects are reviewed on a monthly basis after approval to compare the monthly budget to actual funds spent. We perform a monthly project forecasting exercise to ensure we have a steady and dependable flow of financial information regarding capital expenditures. Through this process, the entire transmission project portfolio is reviewed and consolidated each month. Any variances are immediately addressed. All projects that indicate they may be outside of allowed variances are reevaluated and assessed internally by the Transmission business unit and may be escalated to the corporate level. For larger projects, greater than or equal to $10 million, we adhere to the corporate guidelines to seek "re-approval" of projects outside allowed variances.

Review is also performed to compare year-to-date actual performance with year-to-date and year-end forecasts. Deviations are identified, and recommendations to meet financial targets are reviewed and approved. Changes are reported to the financial performance and planning group, which monitors capital spending.

The Transmission business unit is expected to manage its capital additions to its capital budget once that budget has been developed, fully vetted, and approved. The budgeting process and accountability tools allow us to do so.

Q. HAS PROJECT MANAGEMENT AND BUDGET MANAGEMENT BEEN ONGOING IN THE YEARS SINCE THE COMPANY'S LAST RATE CASE IN 2016?

A. Yes. It is important to our strategic priority of keeping customer bills low to ensure that our budgets and projects are managed effectively year over year. In addition, Company witness Greg P. Chamberlain discusses that the Company's capital true-up has provided additional customer benefits and protections over the last several years, as it ensures customers do not pay for more capital investment than the Company actually makes in a given year. Combined with Transmission's attention to its budgets, there are multiple ways by which the Commission can ensure that our total capital budgets are reasonable in any given year.

C. Capital Investment Trends for 2018 to 2021

Q. FOR 2018 TO 2020, WHAT WERE THE PRIMARY DRIVERS FOR TRANSMISSION'S CAPITAL ADDITIONS?

A. In 2018, Transmission was focused on completing a large Regional Expansion project, the Badger Coulee Project, a MISO designated multi-value project (MVP), which was completed in 2018 (also referred to as the La Crosse–Madison Project). In 2019, our capital investments in Regional Expansion declined as our investments in Asset Renewal projects grew. This greater focus on Asset Renewal projects was due to interrelated factors including a reassessment of our transmission line inspection practices and the age and condition of our transmission facilities. In 2020 and 2021, our investments in Asset Renewal continued to grow as compared to historical trends.

Q. WHY DID THE COMPANY REASSESS THE TRANSMISSION LINE INSPECTION PROGRAMS?

A. We reassessed our inspection programs due to the occurrence of California wildfires in 2018 and 2019 that were caused by Pacific Gas & Electric Co. (PG&E) transmission lines. In particular, the 2018 Camp Fire, caused by sparks from faulty utility equipment, was one of the deadliest and most destructive wildfires in California history. While wildfires are not a high risk in the Midwest, they do occasionally occur, as we saw this past summer, and these events spurred us to examine our system, our inspection practices, and our Asset Renewal programs to ensure that we are making the necessary investments to address these and other risks we face here, such as high winds or ice storms. As a result of this review, we determined a need to increase the frequency of our transmission line inspections to ensure that faulty equipment is identified and addressed in a timely manner.

Q. PLEASE DESCRIBE THESE CHANGES TO THE TRANSMISSION LINE INSPECTIONS.

A. Beginning in 2018, we increased our foot patrols from every six years to every four years, and increased ground line inspections which are completed for each part of our system on a 12-year cycle. The frequency of these inspections was benchmarked against industry practices. In 2019, we also started using Unmanned Aerial Vehicles (drones) to inspect our transmission facilities. In 2020, we inspected over 1,000 miles of line on the NSP Transmission System.

Q. WHAT WAS THE IMPACT OF THESE INCREASED INSPECTIONS?

A. This increase in inspections has resulted in more defects being identified that require repair or replacement. For instance, in 2019, a much higher percentage of poles were ranked as Priority 2 and required immediate replacement as compared to the previous two years. Specifically, in 2017 and 2018, of the total number of poles tested, the percentage of poles ranked as Priority 2 were 1.9 percent and 2.2 percent, respectively. In 2019, the percentage of poles ranked as Priority 2 rose to 5.0 percent of the total poles tested. In 2020, the percentage of poles ranked as Priority 2 stayed higher than historical trends at 4.0 percent.

Given the condition and age of certain of our facilities, this increase in identified defects due to increased inspections is consistent with our expectations. Our wood and steel structures have an expected useful life of 70 years. While steel structures tend to have slightly longer useful lives as compared to wood structures, we utilize 70 years as a guideline for the useful life of both our wood and steel structures. Currently, there are over 500 miles of transmission line that are supported by structures that are 70 years old or older on the NSP Transmission System. While the age of a structure is not necessarily indicative of its condition, older assets are most often the assets where condition may be an issue given the length of time that they have been exposed to the elements.

Q. HOW DID THE COMPANY MAINTAIN THESE TRANSMISSION FACILITIES ABSENT HIGHER CAPITAL INVESTMENT IN PRIOR YEARS?

A. Prior to 2019, we were able to keep these aging transmission assets in working order through general maintenance (O&M costs) and either refurbishment or replacement of specific components when they reached the end of their service life. As part of these refurbishment projects, we replaced only specific components that were in poor condition, like cross-arms, insulators, and some poles, with the existing conductor remaining in-place. Through these refurbishments, we were able to extend the life of these assets by 10 to 20 years depending on asset condition and the scope of the refurbishment.

Q. DO THE CHANGES YOU DISCUSS ABOVE IMPACT TRANSMISSION'S ASSET RENEWAL CAPITAL BUDGET FOR THE MYRP PERIOD?

A. Yes. Over the last five years, we have started to see that assets that were previously refurbished need wholesale replacement. This can either be because of the aggregate condition of all of the components of a circuit (poles, cross-arms, insulators, and conductor) or where the existing design, such as the current pole size, limit our ability to refurbish other components. An example of this would be our lines with copper conductors. When this conductor ages, it becomes brittle. Ideally, we want to replace the conductor and insulators; however, if the existing poles are not able to accommodate the weight of the new conductor and insulators, we need to rebuild the entire line rather than simply replacing the conductor and insulators. As a result, in 2019, we began to identify more lines that required a complete rebuild due to the fact that refurbishment was no longer an option. Given that rebuilds often require more lead time to plan and implement, many of these rebuild projects were set in motion to be placed in service as part of our capital budgets for 2022 through 2024.

Q. DID TRANSMISSION INCREASE ITS CAPITAL INVESTMENTS IN OTHER BUDGET CATEGORIES DURING 2018-2020?

A. Yes. During 2018 to 2020, Transmission also completed work on several Reliability Requirement projects with several of these larger projects going in service in 2018. These projects included the Pomerleau Lake Substation and the Gleason Lake Substation projects in Minnesota in 2018 and the Minot Load Serving Project in North Dakota in 2018.

In 2020, Transmission also increased investments in Interconnection projects such as the Jamaica Substation that was constructed to increase load serving capacity in the southeastern metro area due to a large industrial customer's expansion. Transmission's other investments in Interconnection projects in 2020 included the beginning of retroactive self-funded network upgrade payments to generation developers for Interconnection projects that were completed prior to 2020. I discuss self-funded network upgrade projects in greater detail later in my testimony.

Q. FOR 2018 TO 2021, HOW DID TRANSMISSION'S CAPITAL INVESTMENTS BREAK INTO THE CAPITAL BUDGET GROUPINGS?

A. Table 1 below shows the breakdown of Transmission's capital expenditures by each capital budget grouping for 2018 to 2021. (I note that 2021 is a forecast based on six months of actuals and six months of forecast.)

Table 1

2018-2021 Capital Expenditures

(Excludes AFUDC)

(Dollars in Millions)

NSPM and NSPW (both Total Company)	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Forecast**
Asset Renewal	$70.7	$104.4	$125.3	$173.3
Reliability Requirement	$76.0	$47.5	$38.7	$97.2
Communication Infrastructure	$1.9	$0.9	$0.7	$16.5
Physical Security and Resiliency	$16.5	$19.0	$11.9	$28.3
Interconnection	$10.8	$6.8	$16.6	$43.3
Regional Expansion	$60.1	$14.6	$34.3	$18.7
Total	**$236.0**	**$193.2**	**$227.4**	**$377.3**

Table 2 below shows the breakdown of capital additions by each of the six capital budget groupings for 2018 to 2021. The amounts presented in my testimony include costs currently recovered through the TCR Rider. Mr. Halama will discuss the TCR Rider in greater detail. I am including these amounts here as these projects are part of our overall Transmission capital budget.

Table 2

2018-2021 Capital Plant Additions

(Includes AFUDC)

(Dollars in Millions)

NSPM and NSPW (both Total Company)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast
Asset Renewal	$72.3	$77.6	$102.2	$155.1
Reliability Requirement	$95.5	$39.1	$38.0	$78.8
Communication Infrastructure	$4.5	$0.4	$1.2	$13.5
Physical Security and Resiliency	$14.4	$15.8	$15.4	$29.6
Interconnection	$9.8	$6.7	$17.6	$44.4
Regional Expansion	$183.6	$22.3	$3.5	$53.1
Total	**$380.1**	**$161.8**	**$177.9**	**$374.4**

Q. CAN YOU EXPLAIN THE LARGE AMOUNT OF CAPITAL ADDITIONS IN 2018 AS COMPARED TO 2019 AND 2020?

A. Yes. This is primarily due to the in-servicing of a large Regional Expansion project, Badger Coulee, with $170.2 million in capital additions in 2018. Additionally, in 2018, we also placed in service several larger dollar value Reliability Requirement projects as compared to 2019 and 2020. The Reliability Requirement projects completed in 2018 include the Gleason Lake Substation and Pomerleau Lake Substation projects in Minnesota and the Minot Load Serving Project in North Dakota.

Q. PLEASE EXPLAIN THE INCREASE IN ASSET RENEWAL CAPITAL ADDITIONS FROM 2019 TO 2020.

A. This increase is driven by an increasing investment in our Major Line Rebuild program as compared to prior years. In 2019, Transmission completed three Major Line Rebuild projects compared to eight projects in 2020. As I noted earlier, in 2019, Transmission started identifying more lines on our system that could no longer be refurbished and instead required a complete rebuild.

Q. WHAT ARE THE COMPANY'S FORECASTED CAPITAL ADDITIONS FOR 2021?

A. In 2021, we are forecasting approximately $374.4 million in capital additions, which is an increase from our 2020 actuals of $177.9 million. This increase is driven by greater investments in all of Transmission's capital budget categories.

In Asset Renewal, this increase is due to an increase in our Major Line Rebuild program where we will be completing 12 different rebuild projects as compared to 8 projects in 2020. The increase in the Reliability Requirement category is driven by the in-servicing of several projects, such as the Hibbing Taconite (HibTac) 500 kV Project and upgrades at the Coon Creek Substation in Coon Rapids. The HibTac 500 kV Project involves the removal, replacement, and relocation of 3-miles of 500 kV line to allow expansion of the HibTac mine. The upgrades at the Coon Creek Substation involve replacing both circuit breakers and upgrading three switches at this substation.

Our Communication Infrastructure capital additions are increasing in 2021 due to the commencement of our Communication Network program. This program is aimed at privatizing our communication network to addresses aging analog circuit technology and other technology that is anticipated to become obsolete within five years. Capital additions in our Physical Security and Resiliency category increased due to 25 Physical Security projects that are going in service in 2021. These Physical Security projects improve the security measures at our substations to protect against potential physical threats. Interconnection capital additions increased in 2021 due to one large interconnection project, J512/J569/J587/J590 HNA-SCO. This project rebuilds 17 miles of the Company's Line 0982 in Scott County to increase the ampacity on this line, as requested by MISO, due to the number of generation interconnections in this area. The increase in Regional Expansion capital additions is due to the in-servicing of the Huntley – Wilmarth 345 kV transmission line project which is needed to support increasing renewable generation in southern Minnesota.

D. Overview of Capital Investments for 2022 to 2024

Q. WHAT ARE TRANSMISSION'S CAPITAL BUDGETS FOR 2022 TO 2024 BY CAPITAL BUDGET CATEGORY?

A. Table 3 and Table 4 (and Figures 1 and 2) below provide both planned capital expenditures and additions for 2022 to 2024.

Table 3

2022-2024 Forecasted Capital Expenditures

(Excludes AFUDC)

(Dollars in Millions)

NSPM and NSPW (both Total Company)	**2022 Budget**	**2023 Budget**	**2024 Budget**
Asset Renewal	$278.4	$241.9	$238.6
Reliability Requirement	$47.8	$78.8	$104.1
Communication Infrastructure	$44.5	$39.5	$41.9
Physical Security and Resiliency	$50.8	$38.5	$19.9
Interconnection	$9.7	$23.8	$37.2
Regional Expansion	$16.2	$25.3	$51.1
Totals	**$447.4**	**$447.8**	**$492.7**

Table 4

2022-2024 Forecasted Capital Plant Additions

(Includes AFUDC)

(Dollars in Millions)

NSPM and NSPW (both Total Company)	**2022 Budget**	**2023 Budget**	**2024 Budget**
Asset Renewal	$232.6	$274.5	$218.5
Reliability Requirement	$67.4	$43.4	$39.5
Communication Infrastructure	$48.0	$39.2	$41.6
Physical Security and Resiliency	$49.4	$43.1	$20.2
Interconnection	$9.8	$17.6	$27.1
Regional Expansion	$5.7	$0.7	$14.6
Totals	**$412.9**	**$418.4**	**$361.4**

Figure 1

NSPM and NSPW 2022 – 2024 Capital Expenditures

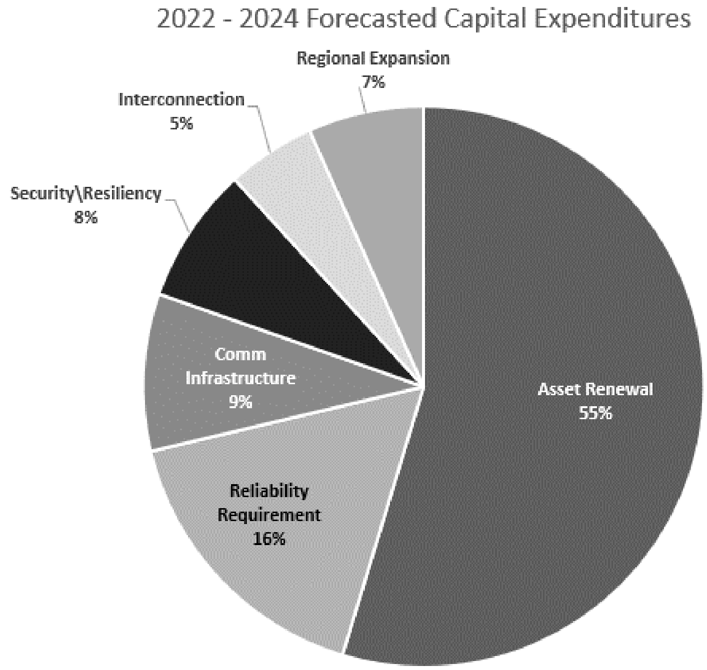
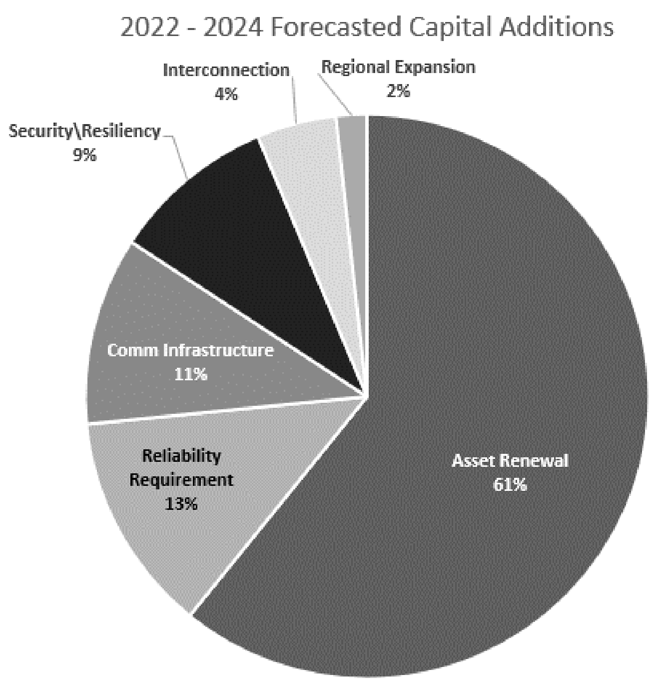


Figure 2

NSPM and NSPW 2022 – 2024 Capital Additions



Q. HOW DO TRANSMISSION CAPITAL INVESTMENTS IN 2022 TO 2024 COMPARE TO HISTORICAL TRENDS?

A. Our 2018 through 2024 capital expenditures and capital additions are set forth in Table 5 and Table 6 below. As these tables illustrate, our capital additions for the MYRP period for nearly every capital budget category, with the exception of Regional Expansion, are higher than our historical investment trends. I discuss the reasons for Transmission's increasing capital investments by capital budget category below.

Table 5

2018-2024 Actual and Forecasted Capital Expenditures

(Excludes AFUDC)

(Dollars in Millions)

NSPM and NSPW (both Total Company)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Asset Renewal	$70.7	$104.4	$125.3	$173.3	$278.4	$241.9	$238.6
Reliability Requirement	$76.0	$47.5	$38.7	$97.2	$47.8	$78.8	$104.1
Communication Infrastructure	$1.9	$0.9	$0.7	$16.5	$44.5	$39.5	$41.9
Physical Security and Resiliency	$16.5	$19.0	$11.9	$28.3	$50.8	$38.5	$19.9
Interconnection	$10.8	$6.8	$16.6	$43.3	$9.7	$23.8	$37.2
Regional Expansion	$60.1	$14.6	$34.3	$18.7	$16.2	$25.3	$51.1
Totals	**$236.0**	**$193.2**	**$227.4**	**$377.3**	**$447.4**	**$447.8**	**$492.7**

Table 6

2018-2024 Actual and Forecasted Capital Plant Additions

(Includes AFUDC)

(Dollars in Millions)

NSPM and NSPW (both Total Company)	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Asset Renewal	$72.3	$77.6	$102.2	$155.1	$232.6	$274.5	$218.5
Reliability Requirement	$95.5	$39.1	$38.0	$78.8	$67.4	$43.4	$39.5
Communication Infrastructure	$4.5	$0.4	$1.2	$13.5	$48.0	$39.2	$41.6
Physical Security and Resiliency	$14.4	$15.8	$15.4	$29.6	$49.4	$43.1	$20.2
Interconnection	$9.8	$6.7	$17.6	$44.4	$9.8	$17.6	$27.1
Regional Expansion	$183.6	$22.3	$3.5	$53.1	$5.7	$0.7	$14.6
Totals	**$380.1**	**$161.8**	**$177.9**	**$374.4**	**$412.9**	**$418.4**	**$361.4**

Q. WHAT IS DRIVING THE INCREASED INVESTMENT IN ASSET RENEWAL FOR 2022 THROUGH 2024 AS COMPARED TO HISTORICAL TRENDS?

A. During the term of this MYRP, Transmission will be making increasing investments in Asset Renewal projects to address the condition of our aging transmission line facilities. As I noted earlier, our increased investment in Asset Renewal started in 2020, and that trend continues through the MYRP period. These investments arose, in part, from the review of our system, our inspection practices, and our Asset Renewal programs that were spurred by the devastating wildfires in California in 2018. While wildfires have historically not been a high risk in the Midwest, they are representative of other risks that our system must be equipped to handle to ensure reliable and safe service. These risks include ice storms or windstorms, such as the derecho that hit the Midwest in August 2020.

As I noted earlier, this review resulted in Xcel Energy increasing the frequency of inspections and, in 2019, utilizing drones to help with these more frequent and more extensive inspections. Transmission uses a defect priority rating system to identify which assets require immediate action (Priority 1 or Priority 2) as well as those that require near-term action (Priority 3 or Priority 4), and those that require monitoring (Priority 5).

These increased and more comprehensive inspections in turn identified a number of defects on our facilities, as we expected given the age of our system. The average life expectancy for wood and steel transmission lines is approximately 70 years. Table 7 below provides a summary of the approximate age of our steel and wood transmission facilities for both NSPM and NSPW.

Table 7

NSPM and NSPW Transmission Facilities

Circuits approximately 70 years old or older by mileage	Circuits approximately 60 years old or older by mileage	Circuits approximately 50 years old or older by mileage
518 miles	1,325 miles	2,786 miles

Over the last five years, we found that assets that Transmission previously repaired or refurbished are now requiring more extensive repairs such as a wholesale rebuild or a more extensive refurbishment. Given that these larger Asset Renewal projects often require more lead time to plan and implement, these projects were set in motion to be placed in service as part of our budgets for 2021 through 2024. As a result, our capital additions in our Major Line Rebuild and Major Line Refurbishment programs are forecasted to be higher than in 2018 to 2020. This increase in investment over prior years is due to both the number of facilities requiring work as well as the extent of the work that will be done.

Q. CAN YOU PROVIDE AN EXAMPLE OF A MAJOR LINE REBUILD PROJECT THAT IS PLANNED TO BE COMPLETED DURING THE MYRP PERIOD?

A. Yes, one of the specific Major Line Rebuild projects that will be completed in nine segments during this MYRP period is the rebuild of the approximately 25-mile Line 0795 West St. Cloud to Wobegon Trail 69 kV line. This line was originally constructed in 1958 and contains approximately 701 structures. Of these 701 structures, 383 contain defects, with some structures containing multiple defects, for a total of 570 defects on this line. Additionally, the cross-arms show evidence of physical decay and the conductor has failed in several locations. In the past five years, there have been more than 20 line outages on this line. Due to the fact that there are known defects on more than half of the structures of the line, rather than simply replace one or two structures, we must rebuild the entire line.

Q. WHAT IS DRIVING THE INCREASE IN COMMUNICATION INFRASTRUCTURE PROJECTS FROM 2022-2024 AS COMPARED TO 2018-2020?

A. As I mentioned above, in 2021, Transmission will be commencing the Communication Network program. From 2022 through 2024, our investments in this program will be steadily increasing as we continue our efforts to privatize Xcel Energy's communication network infrastructure across the NSPM and NSPW service territories to improve SCADA, teleprotection, and remote engineering access, in addition to corporate services. This privatization will also decrease response time for restoring network outages and reduce our exposure to cybersecurity threats through the publicly accessible network provided by third-party telecommunication companies.

Q. WHAT IS DRIVING THE INCREASE IN PHYSICAL SECURITY AND RESILIENCY FROM 2022-2024 AS COMPARED TO 2018-2020?

A. This is due to an increased focus on improving and enhancing the physical security at our critical substation assets in compliance with NERC's CIP-014 Physical Security Standard (NERC CIP-014). The Company also accelerated several physical security projects at certain substations to 2022 and 2023 in response to the Commission's request in 2020 for projects that could help the state's economy recover from the COVID-19 pandemic.[1]

E. Major Planned Investments for 2022 to 2024

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. The MYRP statute, Minn. Stat. § 216B.16, subd. 19, requires that a utility provide "a general description of the utility's major planned investments over the plan period." This section of my testimony discusses the major planned investments Transmission anticipates in 2022 through 2024. The State of Minnesota jurisdictional amounts for each capital addition are included as Exhibit___(IRB-1), Schedule 2.

Q. HOW DID TRANSMISSION IDENTIFY ITS MAJOR PLANNED INVESTMENTS OVER THE PLAN PERIOD?

A. To identify these investments, we looked for those unique projects that require a greater than normal quantity of Transmission resources to complete and that contribute a significant amount to our budgeted capital additions.

[1] See Docket Nos. E,G999/CI-20-492 and E002/M-20-716.

Q. WHAT MAJOR PLANNED INVESTMENTS DOES TRANSMISSION ANTICIPATE COMPLETING OVER THE MYRP PERIOD?

A. As depicted in Table 8, we anticipate undertaking four major planned investments between 2022 and 2024. These investments include two Asset Health programs, NSPW Major Line Rebuild and NSPM Major Line Rebuild, and one Communication Infrastructure program, the Communication Network program, and one Physical Security and Resiliency program, the Physical Security program.

Table 8
Transmission Major Planned Investment Projects
Capital Additions
(Includes AFUDC)
(Dollars in Millions)

	2022 Budget	2023 Budget	2024 Budget
NSPM Major Line Rebuild	$47.40	$90.00	$68.30
NSPW Major Line Rebuild	$12.30	$30.00	$18.70
Communication Network Program	$47.60	$38.80	$41.20
Physical Security Program	$37.80	$30.80	$16.20

These major planned investments, as well as the additional key capital projects we anticipate completing in 2022, 2023, and 2024 are discussed in more detail below.

F. Key Capital Additions for 2022 to 2024

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I describe the main projects under each of the capital budget groupings I identified earlier. Unless otherwise stated, all dollar figures are at the NSPM and NSPW Total Company level. These capital additions are presented in State of Minnesota Electric Jurisdiction form in Exhibit___(IRB-1) Schedule 2.

1. *Asset Renewal Programs and Projects*

Q. WHAT IS THE PRIMARY CHALLENGE FACING TRANSMISSION RELATED TO ASSET RENEWAL?

A. The primary challenge that Transmission faces related to Asset Renewal is the number of facilities that will require investment in the coming years to maintain the reliability and safety of our transmission system. Our organization is charged with maintaining a large and aging transmission infrastructure. While transmission facilities generally have long lifespans, these facilities do not last forever. As I mentioned, many of our transmission facilities as well as those around the country are reaching the end of their useful life as many were placed in service in the 1950s and 1960s during the economic boom that followed World War II. On the NSP Transmission System, there is more than 500 miles of line that is 70 years old or older, more than 1,300 miles that is 60 years old or older, and over 2,700 miles that is 50 years old or older. Likewise, substation transformers have an expected life of between 50 to 65 years and 217 of NSPM's 675 substation transformers are 50 years old or older.

We do not simply replace a transmission asset due to its age, however. Instead, the Company examines both the condition and performance of our aging facilities to determine which facilities are in greatest need of replacement. We also prioritize replacement of aging facilities based on which facilities are most likely to fail and then which equipment will have the biggest impact on the transmission system when it does fail.

Q. WHY ARE INVESTMENTS IN ASSET RENEWAL INCREASING OVER THE TERM OF THIS MYRP?

A. Over the term of this MYRP, we will be making greater investment in Asset Renewal programs and projects to address the deteriorating condition of our aging transmission facilities. This increase in investments in this area is the result of several interrelated factors. As I discussed earlier, one of the key events that eventually led to greater investment in this category was the California wildfires in 2018. While wildfires have historically not been a big risk in the Midwest, they highlighted for our Company and the industry the need to ensure that transmission assets are safe, reliable, and able to withstand extreme events.

In response, we examined our Asset Renewal programs, our inspection frequency, and our investment strategy. One outcome of this examination was more frequent and more comprehensive inspections of our facilities that resulted in identification of more deficiencies. This in turn led to a need to increase our budgets to make these necessary repairs, refurbishments, or rebuilds. Moreover, while we have been making steady investments in the maintenance and repair of our transmission assets, many of our assets are at the point where they require wholesale replacement or rebuild rather than less costly repairs or refurbishments.

Q. PLEASE EXPLAIN HOW INSPECTIONS ARE USED TO IDENTIFY ASSET RENEWAL PROJECTS.

A. The Company performs various types of assessments on the transmission line facilities at different points in time. Beginning in 2018, we began increasing our foot patrols from every six years to every four years and increased ground line inspections, which are completed on all structures on a 12-year cycle. In 2019, we also started using Unmanned Aerial Vehicles (drones) to inspect all of our all NERC FAC-003 reliability standard (200 kV and above) transmission facilities on an annual basis.

Q. HOW DOES TRANSMISSION EVALUATE THE CONDITION OF ITS FACILITIES?

A. Transmission utilizes a defect priority rating system to rank the condition of our transmission facilities. This rating system utilizes a ranking from Priority 1 to Priority 5, with Priority 1 ranking indicating that a component requires immediate action. I summarize this ranking system in the table below.

Table 9

Defect Priority Rankings

Priority Ranking	Maintenance Priority and Maintenance Action	Asset Management Implication
Priority 1	Emergency; Immediate Action Required	Failed Component with or without service interruption
Priority 2	Emergency; Urgent Action Required	Failure imminent-component damaged or no longer suitable for intended use. Service not yet interrupted but failure or service interruption is imminent.
Priority 3	High Priority	Asset renewal required-significant wear, corrosion or damage to warrant action plan.
Priority 4	Medium Priority	Asset renewal recommended-moderate to minimal wear, corrosion, or damage to warrant action plans.
Priority 5	Low Priority	Minimal maintenance-minor wear, corrosion, etc. but still functional condition for the intended purpose.

The components that are designated as Priority 1 or Priority 2 require urgent action and therefore are typically funded out of our Storm and Emergencies (S&E) programs. Those assets labeled Priority 3 to Priority 5 require action but not immediately, so the replacement and repair of these components is typically funded through our other Asset Renewal programs such as our Major Line Rebuild or End-of-Life programs.

Q. WHAT IS THE NEXT STEP AFTER AN ASSET IS CATEGORIZED BY PRIORITY?

A. In these assessments, the Company identifies those transmission lines that require rebuilding, and specific projects are subsequently developed and prioritized using the Company's Line Prioritization Matrix, which is a tool developed by the transmission line performance group that uses internal and external information to quantitatively rank each transmission circuit. Each line is scored and ranked against each other incorporating the following drivers:

- Importance
  - What happens if the circuit has an outage
  - Operational concerns
  - Design concerns
- Reliability
  - Frequency of outages
  - Duration of outages
  - Benchmarking rating
- Condition Assessment
  - Incorporates two scoring groups
    - Field Engineer's Field Assessment
    - Transmission Asset Management System (TAMS) Identified Defects
      - Defect count and severity
      - Repair cost estimates

Through the assessment process, the Company may identify defective line circuits requiring a full rebuild as early as five years before the rebuild is needed. However, we typically budget lines for this program only two to three years in advance because upgrades in the system area, storms and emergencies, and changing system needs may alter the overall asset health score for identified lines beyond the two- to three-year window. The Company identifies, budgets for, and develops specific projects during our annual budget process and on the basis of the total asset health score of the line as determined by the Line

Prioritization Matrix. These individual projects are then prioritized against the rest of the planned Transmission capital portfolio. Lastly, the Company budgets for projects in the three- to five-year range based on the remaining projects that are in the top quartile of the Line Prioritization Matrix following the historical trends of this program.

Q. PLEASE PROVIDE A GENERAL OVERVIEW OF TRANSMISSION'S ASSET RENEWAL PROGRAMS.

A. Transmission's Asset Renewal programs are used to fund yearly replacement and refurbishment of key transmission facilities. Many of Transmission's Asset Renewal programs are focused on replacing equipment or facilities that have reached the end of their service life. These programs are referred to as End-of-Life or ELR programs. Transmission also has Asset Renewal programs that are focused on replacing assets that unexpectedly fail due to storms or other causes.

Q. WHAT ARE THE KEY ASSET RENEWAL PROGRAMS THAT HAVE INVESTMENTS DURING THE MYRP PERIOD?

A. The key Asset Renewal programs that have assets that will be placed in service between 2022 and 2024:

1. NSPM and NSPW Major Line Rebuild program,
2. NSPM and NSPW S&E Line and Substation programs,
4. NSPM and NSPW Substation Breakers ELR program,
5. NSPM and NSPW Major Line Refurbishment program,
6. NSPM Nuclear Substation ELR program,
7. NSPM Steel Pole Replacement program,
8. NSPM and NSPW Relay ELR program,
9. NSPM and NSPW Line ELR program, and

10. NSPM and NSPW Transformers ELR program.

Table 10 below summarizes the budgeted capital additions for each of these programs during the term of this MYRP.

Table 10
Key Asset Renewal Programs
2022-2024 Capital Plant Additions
(Dollars in Millions)

NSPM and NSPW (both Total Company)	2022 Budget	2023 Budget	2024 Budget
Major Line Rebuild program	$59.6	$120.0	$87.1
S&E Line and Substation programs	$26.4	$25.0	$24.0
Major Line Refurbishment program	$25.3	$14.0	$15.9
Substation Breakers ELR program	$16.9	$22.8	$12.8
Relay ELR program	$12.5	$11.4	$9.3
Nuclear Substation ELR program	$10.4	$11.1	$9.9
Transformers ELR program	$13.0	$9.8	$4.9
Line ELR program	$8.5	$9.5	$7.8
Steel Pole Replacement program	$9.6	$5.9	$4.5
Total Asset Renewal	**$182.2**	**$229.5**	**$176.1**

Q. OUTSIDE OF THESE ASSET RENEWAL PROGRAMS, DOES TRANSMISSION ALSO HAVE DISCRETE ASSET RENEWAL PROJECTS?

A. Yes. Transmission also completes individual Asset Renewal projects to replace and upgrade facilities that are in need of replacement. There are three key Asset Renewal projects that will be placed in service during the term of this MYRP:

- Eau Claire 345 kV Upgrade,
- Replace optical ground wire (OPGW) on Line 0953, and

- W3203 Briggs-La Crosse Line Upgrade Project.

Q. DOES THE COMPANY'S ASSET RENEWAL BUDGET INCLUDE ANY ACCELERATED WORK ASSOCIATED WITH THE COMPANY'S COVID-19 RELIEF & RECOVERY DOCKET?

A. Yes. In response to the Commission's request for projects that could assist with Minnesota's economic recovery from the COVID-19 pandemic, the Company accelerated several Asset Renewal projects.[2] Table 11 below summarizes the Asset Renewal projects that will be accelerated and in-serviced in 2021, 2022, 2023, and 2024. Consistent with the Commission's March 12, 2021 Order,[3] the Company has been tracking its spending related to these COVID-19 Relief & Recovery projects and the Company has been providing this information to the Commission as part of its quarterly compliance filings in that docket.[4]

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[2] *In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery form the COVID-19 Pandemic*, REPORT COVID-19 RELIEF & RECOVERY, Docket No. E,G999/CI-20-492 (June 17, 2020).

[3] *In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery form the COVID-19 Pandemic*, ORDER DETERMINING THAT PROPOSALS HAVE THE POTENTIAL TO BE CONSISTENT WITH COVID-19 ECONOMIC RECOVERY, Docket No. E,G999/CI-20-492 (March 12, 2021).

[4] *In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery form the COVID-19 Pandemic*, 2021 SECOND QUARTER REPORT COVID-19 RELIEF & RECOVERY, Docket No. E,G999/CI-20-492 (July 30, 2021).

Table 11
NSPM Transmission Asset Health Projects
for COVID-19 Relief & Recovery
Capital Additions
(Dollars in Millions)

Project Name	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Major Line Rebuild program	$0.0	$14.1	$52.1	$56.2
Substation Breakers ELR program	$0.0	$4.0	$14.7	$9.8
Steel Pole Replacement program	$0.2	$9.6	$5.9	$4.5
S&E Line and Substation programs	$0.0	$8.0	$6.0	$6.0
Line ELR program	$3.5	$5.0	$5.8	$4.6
Transformers ELR program	$0.1	$5.7	$4.0	$3.0
Relay ELR program	$0.0	$0.0	$1.5	$4.2
Major Line Refurbishment program	$0.1	$2.7	$0.0	$0.0
Total	**$4.0**	**$49.0**	**$90.1**	**$88.4**

Q. HOW DO CUSTOMERS BENEFIT FROM THE ACCELERATION OF THESE ASSET RENEWAL PROJECTS?

A. As discussed above, Asset Renewal projects in general are aimed at ensuring that critical assets – transmission lines, substations, and other assets – are reliable and in good working condition. The benefits of our Asset Renewal projects are that they reduce failures on our system which improve reliability and safety for our customers and workers. Acceleration of these Asset Renewal projects will bring these important benefits to our customers sooner.

a. Asset Renewal Programs

(1) Major Line Rebuild

Q. PLEASE DESCRIBE THE NSPM/NSPW MAJOR LINE REBUILD PROGRAM.

A. The Major Line Rebuild program for NSPM and NSPW represents projects that rebuild large segments of transmission lines on the NSP Transmission System that have a concentrated number of defects that contribute to poor line performance. These projects are typically required either because the existing line circuits are at risk for increased outage frequency or because the number of structural defects on the circuit makes it unreasonable to refurbish only the defective portions. A rebuild project scope requires complete wreck-out/removal of the physical line assets, which are then replaced with new line assets (*e.g.,* structures, conductor, switches) either within the existing right-of-way (ROW) or with minor, targeted ROW expansion to accommodate outage constraints and safe construction practices.

Q. WHAT PLANT ADDITIONS ARE BUDGETED FOR 2022 TO 2024 AS PART OF THE MAJOR LINE REBUILD PROGRAM?

A. The Company has budgeted $205.7 million for the NSPM Major Line Rebuild program ($47.3 million in 2022; $90.0 million in 2023; and $68.3 million in 2024). The Company has budgeted $60.9 million for the NSPW Major Line Rebuild program ($12.3 million in 2022, $30.0 million in 2023, and $18.7 million in 2024).

Q. WHAT IS DRIVING THE INCREASED INVESTMENT IN MAJOR LINE REBUILDS OVER THE TERM OF THE MYRP?

A. These increased investments are driven by both the condition and age of our transmission assets. As I discussed earlier, until recently we have been able to maintain the majority of our assets through either O&M repairs, replacement of specific components when they are at the end of their service life, or refurbishment projects that extend the life of our assets by 10 to 20 years depending on asset condition and the scope of the refurbishment. Recently, our inspections are revealing that lines that were previously refurbished are in need of replacement due to the cumulative condition of the asset (poles, cross-arms, insulators, and conductor), as well as lines where their general composition, like conductor type, framing, and pole sizes would not safely allow for refurbishment. As a result, we need to increase our investments in our Major Line Rebuild programs to rebuild these lines.

Q. HAS TRANSMISSION IDENTIFIED SPECIFIC MAJOR REBUILD PROJECTS THAT WILL BE COMPLETED DURING THIS MYRP?

A. Yes. These rebuild projects are typically identified the year prior to the start of construction so Transmission has a list of rebuild projects for 2022 that are enumerated in Exhibit___(IRB-1), Schedule 3.

Q. CAN YOU DESCRIBE ONE OF THE SPECIFIC MAJOR LINE REBUILD PROJECT THAT TRANSMISSION WILL COMPLETE IN 2022?

A. Yes. The Lake City to Zumbrota Rebuild project involves rebuilding an approximately 15-mile segment of this 69 kV transmission line (also known as Line 0761), which is over 60 years old. This transmission line originates at the Company's Zumbrota Substation in southeastern Minnesota and runs northeast approximately 15 miles to the Lake City Substation in Lake City, Minnesota. This line is critical to the reliability of this area because it serves the Company's as well as other utilities' distribution loads in the area.

Q. PLEASE DESCRIBE ANOTHER MAJOR LINE REBUILD PROJECT THAT THE COMPANY PLANS TO COMPLETE DURING 2022 – 2024 TIMELINE?

A. Another project is the Farmington – Pilot Knob Rebuild project. The scope of this project is to rebuild approximately 7 miles of existing 69 kV transmission line between the Kegan Lake Tap and the Farmington Substation and approximately 1.6 miles of 69kV line between Farmington and Northfield substations. Much of this line was originally constructed in 1924 and 1954. The existing structures are early vintage steel lattice towers and are in poor condition. As part of this project, these structures will be replaced with steel monopole structures utilizing braced post insulators.

(2) Storm and Emergencies Line and Substation Programs

Q. PLEASE DESCRIBE THE NSPM/NSPW S&E LINE AND SUBSTATION PROGRAMS.

A. The S&E Line program replaces and repairs equipment that has failed due to a storm event or that is identified through condition assessment as having a high probability of failure and cannot wait for the next normal budget cycle for replacement (*i.e.*, either Priority 1 or Priority 2). This work is typically performed in response to weather events, unforeseen events, and other unscheduled maintenance work that, if not completed, puts the equipment at imminent risk of failure. The work typically includes the replacement of arms, poles, conductor, insulators, and other line appurtenances.

The S&E Substation program replaces and repairs equipment that has failed due to a storm event or that is identified through condition assessment as having a high probability of failure and cannot wait for the next normal budget cycle for replacement. This work typically includes the replacement of small substation assets such as reactors, non-performing relays, switches, and DC battery systems.

Q. WHAT RECENT TRENDS HAVE YOU SEEN IN THE S&E LINE AND SUBSTATION PROGRAMS?

A. We have recently seen more poles classified as Priority 2 (*i.e.*, requiring immediate replacement through our S&E program) than in prior years. Specifically, in 2017 and 2018, the percentages of poles categorized as Priority 2 were 1.9 percent and 2.2 percent respectively of the total number of poles tested. In 2019, the number of poles classified as Priority 2 rose to 5.0 percent of the total poles tested and in 2020 the number of poles classified as Priority 2 remained above the 2017 and 2018 historical levels at 4.0 percent. This recent increase in Priority 2 classifications underscores the importance of continued inspections and continued funding for this program to address these urgently needed replacements.

Q. HOW DOES TRANSMISSION DETERMINE THE BUDGET FOR THE S&E LINE AND SUBSTATION PROGRAMS?

A. The Company sets its budget for this program in two parts; the first is based on a historical annual average because the nature of the work to be performed is not known until the time of an incident and the second, a recent change in program's budgeting practice, is based on an estimated unit cost for pole replacement as part of the Priority Pole Replacement inspection plan. The forecast is then adjusted throughout the year based on actual incidents and confirmed defective poles through inspection, while factoring in the probability of storm or emergency events for the remainder of the calendar year.

Q. WHAT PLANT ADDITIONS ARE BUDGETED FOR 2022 TO 2024 FOR THE NSPM/NSPW S&E LINE AND SUBSTATION PROGRAM?

A. The Company has budgeted $56.5 million for the NSPM S&E Line and Substation program ($20.1 million in 2022; $18.8 million in 2023; and $17.7 million in 2024). The Company has budgeted $18.9 million for the NSPW S&E Line and Substation program ($6.3 million in 2022; $6.2 million in 2023; and $6.3 million in 2024).

(3) Substation Breaker ELR Program

Q. PLEASE DESCRIBE THE NSPM/NSPW SUBSTATION BREAKER ELR PROGRAM.

A. The NSPM/NSPW Substation Breaker ELR program targets substation circuit breakers for replacement that have been identified due to poor performance or lack of available replacement parts for repair. As transmission infrastructure ages or nears its expected end of life, components must be changed before failures occur. As the structural integrity of these aging assets diminishes, outages will increase in frequency and duration.

As with the ELR – Relay program, while we may identify a number of circuit breakers through the Substation Breaker ELR program that require replacement as early as five years in advance, typically we budget lines for this program only two to three years in advance. During our annual budget process, the poorest performing circuit breaker projects are included in the budget. These projects are then prioritized against the rest of the planned Transmission portfolio. Budgets for projects in the three- to five-year- range are then planned for based on the age and asset health of these circuit breakers. The pace of this replacement program may vary because many aging breakers may still be functional but do not offer optimal operational performance. As such, the replacement of components identified in this program can be accelerated or decelerated dependent on other Transmission portfolio needs.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2022 THROUGH 2024 FOR THE NSPM/NSPW SUBSTATION BREAKER ELR PROGRAM?

A. The Company has budgeted $37.5 million for the NSPM Substation Breaker ELR program ($8.5 million in 2022; $19.2 million in 2023; and $9.8 million in 2024). The Company has budgeted $14.9 million for the NSPW Substation Breaker ELR program ($8.4 million in 2022; $3.6 million in 2023; and $3.0 million in 2024).

Q. CAN YOU PROVIDE AN EXAMPLE OF A SUBSTATION BREAKER ELR PROJECT THAT WILL BE COMPLETED DURING THE MYRP?

A. Yes, one of the projects that we plan to complete during the term of this MYRP is the replacement of all three of the 115 kV circuit breakers at the Fifth Street Substation that serves downtown Minneapolis. The age of these circuit breakers range from 53 to 56 years old. The average service life of a circuit breaker is approximately 50 years. Given the importance of these circuit breakers in serving the large downtown load, a failure of any one of these breakers could result in a large number of customers being without service. As a result, it is important to replace these three circuit breakers at this time given that they are already past their expected service life. We have budgeted $1.1 million in capital additions to complete this project in 2022.

(4) Major Line Refurbishment Program

Q. PLEASE DESCRIBE THE NSPM/NSPW MAJOR LINE REFURBISHMENT PROGRAM.

A. The Major Line Refurbishment program for NSPM and NSPW encompasses a group of targeted projects to replace specific transmission line components, such as defective cross-arms, poles, and other line appurtenance components. This program differs from the Major Line Rebuild program in that the Major Line Rebuild program involves the complete removal and replacement of existing assets; whereas the Refurbishment program addresses specific defects on an entire line segment (breaker to breaker), replacing all like property units on the line segment.

The Company identifies these defective components as at or near failure by means of routine foot patrols, aerial patrols, or Field Engineer's Field Assessment (which occurs only as required by damage reports—an estimated 2 percent of all lines annually). By refurbishing specific components of a line segment, rather than rebuilding an entire line, the Company's intent is to increase circuit reliability and performance and extend the residual circuit life by between 10 to 20 years, at a lower cost than a full line replacement.

Similar to our Major Line Rebuild program, the Company utilizes its assessment of the transmission system to help identify specific projects, which are then developed and prioritized in accordance with the Company's Line Prioritization Matrix. As with the Major Line Rebuild program, each transmission line is scored and ranked against each other based on the drivers noted above.

As with the Major Line Rebuild program assessment process, the Company may identify defective line circuits requiring refurbishment as early as five years before repairs are necessary. However, we typically budget lines for this program only two to three years in advance because upgrades in the system area, storms and emergencies, and changing system needs may alter the overall asset health score for identified lines beyond the two- to three-year window. The Company identifies, budgets for, and develops specific projects during our annual budget process and on the basis of the total asset health score of the line as determined by the Line Prioritization Matrix. These individual projects are then prioritized against the rest of the planned Transmission capital portfolio. Lastly, the Company budgets for projects in the three- to five-year range based on the remaining projects that are in the top quartile of the Line Prioritization Matrix following the historical trends of this program.

Q. WHAT PLANT ADDITIONS WILL OCCUR FROM 2022 THROUGH 2024 AS PART OF THE MAJOR LINE REFURBISHMENT PROGRAM?

A. The Company has budgeted $35.4 million for the NSPM Major Line Refurbishment program ($15.7 million in 2022, $9.8 million in 2023, and $9.8 million in 2024). The Company has budgeted $19.7 million for the NSPW Major Line Refurbishment program ($9.6 million in 2022, $4.1 million in 2023, and $6.0 million in 2024).

Q. CAN YOU PROVIDE INFORMATION ABOUT A SPECIFIC REFURBISHMENT PROJECT THAT WILL BE COMPLETED DURING THE TERM OF THIS MYRP?

A. Yes, included in this program is a refurbishment of the Company's 69 kV transmission line between the Company's Westgate Substation, in Eden Prairie, Minnesota and the Company's Excelsior Substation in the western Minneapolis suburbs. This refurbishment project encompasses the entire length of the line, which is approximately 11 miles. The scope of the project includes the removal of all existing wood cross-arms. The wood cross-arms have decayed over time and are beyond their useful life. These assets will be replaced with new horizontal post insulators. In addition, the project includes the complete removal and replacement of 32 poles that have been identified as defective though our comprehensive inspection program. In total, approximately 185 structures will be modified, and 32 wood poles will be replaced. We have budgeted $4.6 million in capital additions to complete this project in 2022.

(5) Nuclear Substation ELR Program

Q. PLEASE DESCRIBE THE NSPM NUCLEAR SUBSTATION ELR PROGRAM.

A. This program has been separated from the Company's other ELR programs so that it can more easily be completed in coordination with our Nuclear business unit's compliance needs. The Nuclear Substation ELR program addresses the programmatic replacement of substation equipment at the substations that serve the Monticello and Prairie Island nuclear generating plants. The timing of these replacements is designed to align Transmission's substation replacement activities with power plant refueling and maintenance activities at these two nuclear facilities. The equipment identified for replacement consists largely of circuit breakers, switches, relays, and power transformers. While the program can be flexible from year to year, replacement of these facilities is necessary to maintain the ability of the transmission system to transport the energy generated by these plants to customers.

Q. CAN YOU PROVIDE AN EXAMPLE OF A NUCLEAR SUBSTATION ELR PROJECT THAT WILL BE COMPLETED DURING THE MYRP?

A. Yes, one of the projects that we be completing is the Monticello Substation project which involves replacing one transformer and six breakers at the Monticello Substation. We have budgeted $8.7 million in capital additions to complete this project ($1.9 million in 2022, $1.8 in 2023, and $5.0 million in 2024).

Q. WHAT PLANT ADDITIONS WILL OCCUR FROM 2022 THROUGH 2024 FOR THE NSPM ELR NUCLEAR PROGRAM?

A. The Company has budgeted $31.4 million in capital additions for the NSPM ELR Nuclear program ($10.4 million in 2022; $11.1 million in 2023; and $9.9 million in 2024).

(6) Steel Pole Replacement Program

Q. PLEASE DESCRIBE THE STEEL POLE REPLACEMENT PROGRAM.

A. This is a new program to address the condition of steel pole surface coating on certain types of structures. During the term of this MYRP, we plan to complete one project as part of this program: the Main Street to Riverside Steel Pole Replacement project north of downtown Minneapolis. These existing structures were installed in the 1980's and are experiencing paint peeling and steel deterioration. Without this project, the protective coating on these structures will continue to deteriorate, exposing additional unprotected steel, and the currently exposed steel will continue to corrode. These poles support critical transmission lines that serve downtown Minneapolis. This project involves replacing approximately 4 miles of triple circuit structures (approximately 35 structures) with new galvanized or weathering steel structures. New concrete foundations will be needed on four of the 35 structures. The last phase of work will be the installation of OPGW between the Riverside and Main Street substations.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2022 TO 2024 FOR THE STEEL POLE REPLACEMENT PROGRAM?

A. The Company has budgeted a total of $20.0 million for the Steel Pole Replacement program ($9.6 million in 2022; $5.9 million in 2023; and $4.5 million in 2024).

(7) Relay ELR Program

Q. PLEASE DESCRIBE THE NSPM/NSPW ELR – RELAY PROGRAM.

A. Protective relays monitor power system quantities, typically voltages and currents, and open and close circuits to remove short circuits from the power system.

The ELR – Relay program encompasses projects that target relays for replacement that exhibit poor performance and lack available replacement parts. As transmission infrastructure continues to age or nears or is at its end of life, these components must be changed before failures occur. As the structural integrity of aging assets diminishes, outages will increase in frequency and duration.

While we may identify a number of relays that require replacement as early as five years in advance of the asset's end of life, we typically budget for this program only two to three years in advance. During our annual budget process, the poorest performing relays are added to the budget. These projects are then prioritized against the rest of the planned Transmission portfolio. Budgets for projects in the three- to five-year range are then planned for transmission's remaining relay infrastructure based on age and asset health. The pace of this replacement program may vary because many aging relays may still be functional but do not offer optimal operational performance. As such, the replacement of components identified in this project can be accelerated or decelerated dependent on other Transmission portfolio needs.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2022 THROUGH 2024 FOR THE ELR – RELAY PROGRAM?

A. The Company has budgeted a total of $33.2 million for the ELR – Relay program: $20.7 million for the NSPM ELR – Relay program ($6.8 million in 2022; $8.2 million in 2023; and $5.6 million in 2024) and $12.5 million for NSPW ELR – Relay program ($5.7 million in 2022; $3.1 million in 2023; and $3.7 million in 2024).

Q. CAN YOU PROVIDE AN EXAMPLE OF AN ELR – RELAY PROJECT THAT WILL BE COMPLETED DURING THE TERM OF THIS MYRP?

A. Yes, an example of one of these projects is the replacement and upgrading of the relaying at the Riverside Substation that serves north Minneapolis. This project is part of a larger effort to phase out older technology relaying systems on the transmission system. The relays at the Riverside Substation include older electro-mechanical relays as well as first generation microprocessor relays. These types of relays have been targeted for replacement primarily due to poor performance and lack of replacement parts. We have budgeted $1.0 million in capital additions to complete this project in 2022.

(8) Line ELR Program

Q. PLEASE DESCRIBE THE NSPM/NSPW LINE ELR PROGRAM.

A. The Line ELR program for NSPM and NSPW encompasses projects that target the replacement of defective cross arms, poles, and other line appurtenance components on the NSP Transmission System that have been reported as defective by routine foot and aerial patrols and are nearing their end of life. Overall, the Line ELR program extends the life of NSP transmission line assets when full line replacement is not necessary. Line ELR is utilized primarily when the individual defect has occurred, but the overall line segment is otherwise in sound condition with many years of additional life remaining.

Q. HOW DOES THE LINE ELR PROGRAM DIFFER FROM THE MAJOR LINE REFURBISHMENT PROGRAM DISCUSSED ABOVE?

A. The Major Line Refurbishment program replaces specifically identified defective transmission line property units (cross-arms or poles or other line appurtenances) when the majority of similar property units of the same vintage and design have been identified as defective on a line circuit. Any property units found to be in good operational condition are left in place.

In contrast, the Line ELR program replaces only individual transmission line property units that are defective, but not similar property units of the same vintage and design that are generally in good operating condition.

When defects are identified through patrols, typically one to three years in advance, they are classified as either Major Line Refurbishment or Line ELR, and they are budgeted and executed. These two programs are managed separately because the severity of the identified defects on a circuit, along with the frequency of the defects, determines which program's budget will be utilized.

Q. WHAT PLANT ADDITIONS WILL OCCUR FROM 2022 THROUGH 2024 FOR THE LINE ELR PROGRAM?

A. The Company has budgeted $16.0 million for the NSPM Line ELR program ($5.2 million in 2022; $6.0 million in 2023; and $4.8 million in 2024). The Company has budgeted $9.8 million for the NSPW Line ELR program ($3.3 million in 2022; $3.5 million in 2023; and $3.0 million in 2024).

(9) Transformers ELR Program

Q. PLEASE DESCRIBE THE NSPM/NSPW TRANSFORMERS ELR PROGRAM.

A. The NSPM/NSPW Transformers ELR program targets transformers for replacement that have been identified due to poor performance or lack of available replacement parts for repair. As transmission infrastructure ages or nears or is at its expected end of life, components must be changed before failures occur. As the structural integrity of these aging transformer assets diminishes, outages will increase in frequency and duration.

As with the other ELR programs (Relays and Circuit Breakers), we may identify a number of transformers through the Transformer ELR program that require replacement as early as five years in advance but, typically we budget lines for this program only two to three years in advance. During our annual budget process, the poorest performing transformers are included in the budget for replacement. These projects are then prioritized against the rest of the planned Transmission portfolio. Budgets for projects in the three- to five-year range are then planned for based on the age and asset health of these assets. The pace of this replacement program may vary because many aging transformers may still be functional but do not offer optimal operational performance. As such, the replacement of components identified in this program can be accelerated or decelerated dependent on other Transmission portfolio needs.

Q. WHAT PLANT ADDITIONS WILL OCCUR IN 2022 THROUGH 2024 FOR THE NSPM/NSPW TRANSFORMERS ELR PROGRAM?

A. The Company has budgeted $12.7 million in capital additions for the NSPM Transformers ELR program ($5.7 million in 2022; $4.0 million in 2023; and $3.0 million in 2024). The Company has budgeted $15.0 million in capital additions for the NSPW Transformers ELR program ($7.2 million in 2022; $5.8 million in 2023; and $1.9 million in 2024).

Q. PLEASE PROVIDE AN EXAMPLE OF A TRANSFORMER ELR PROJECTS THAT WILL BE COMPLETED DURING THE TERM OF THIS MYRP.

A. One of these projects involves the replacement and upgrade of the 300 MVA Eau Claire Substation transformer and both sets of the tertiary reactors for this transformer. Further, as part of this project, substation grounding and the AC auxiliary system will be brought into alignment with current standards. This project was initiated as part of an ELR review of system transformers. During initial scoping, it was determined that the tertiary reactors for this transformer needed to be replaced since they are in need of significant maintenance and are reaching the end of their life. After identifying the replacement of these reactors, we also examined the transformer and determined that it needed replacement due to detection of degradation of transformer gasses. We further determined that this transformer needed to be upgraded to 448 MVA to allow for future load growth in this area. We have budgeted $3.7 million in capital additions to complete this project in 2022.

b. Discrete Asset Renewal Projects

Q. DESCRIBE THE EAU CLAIRE 345 KV UPGRADE PROJECT.

A. This project involves replacing all of the existing wood structures on the 164-mile 345 kV line between the A.S. King Substation in St. Paul, Minnesota and the Arpin Substation south of Marshfield, Wisconsin. Most of these existing wood structures are approximately 50 years old and near the end of their design life. The existing conductor and shield wire would be reattached to the new structures. This is a multi-year project that will commence in 2022 and will have $53.6 million in capital additions during the term of this MYRP ($21.4 million in 2022, $16.3 million in 2023, and $15.9 million in 2024).

Q. DESCRIBE THE REPLACEMENT OPGW ON LINE 0953 PROJECT.

A. This project will replace the OPGW on Line 0953 between the Nobles County Substation near Worthington, Minnesota and Split Rock Substation in Minnehaha County in South Dakota. The existing OPGW has been damaged by lightning and will be replaced with new OPGW rated to withstand a high volume of lightning strikes. All existing suspension, dead-end, and splice hardware will also be replaced. This is a multi-year project that will have $8.9 million in capital additions during the term of this MYRP ($4.2 million in 2022 and $4.7 million in 2023).

Q. DESCRIBE THE W3203 BRIGGS-LA CROSSE LINE UPGRADE PROJECT.

A. This project involves rebuilding the W3203 Briggs – La Crosse line. This is a 10-mile, 161 kV transmission line located between the Company's Briggs Road

Substation located near Holmen, Wisconsin and La Crosse Substation in La Crosse, Wisconsin. In 2016, this project was first identified as Major Line Refurbishment project due to the age and condition of certain elements of the line. However, during the 2019 annual transmission planning analysis, this line was identified as being close to the thermal limits under contingency conditions. As a result, it was recommended that the conductor of the line be upgraded. In the 2020 annual transmission planning analysis, this line was identified as exceeding thermal limits in the 2024 summer peak and light load cases under multiple contingencies in the area and as requiring mitigation under NERC's TPL-001-4 reliability standard requirements. As a result, the scope of the project was expanded to include upgrading the conductor size and all terminal end switches to meet NERC's TPL-001-4 reliability standard requirements. Upgrading the conductor will also require all of the existing poles to be replaced in order to accommodate the new conductor. This project is in the final design and engineering phase with construction scheduled to begin in 2022. This project will have $8.6 million in capital additions during the term of this MYRP ($5.3 million in 2023 and $3.3 million in 2024).

2. *Reliability Requirement Projects*

Q. WHAT IS DRIVING THE COMPANY'S INVESTMENTS IN RELIABILITY REQUIREMENT PROJECTS?

A. NERC develops and enforces reliability standards on all transmission owners, operators, and users. The Company performs transmission planning studies to identify necessary upgrades to the system to ensure compliance with NERC reliability standards. Through these studies, transmission planners evaluate all various alternatives to meet the identified electrical needs for the system and select the option that considers the incremental impact of the project for future needs in the area and best meets the long-term electrical needs of the area in a cost effective- manner. This category of projects also includes transmission improvements that are needed to improve the reliability in our system where the operating voltage of the system being improved is below NERC regulation; these projects would typically be adding operational redundancy to our 34.5 kV, 69 kV and 88 kV transmission systems.

Q. WHAT WOULD BE THE IMPACT OF EITHER FORGOING OR DEFERRING A RELIABILITY REQUIREMENT PROJECT?

A. Deferring or forgoing a necessary Reliability Requirement project could impact system reliability. Further, if the project is needed to meet a NERC reliability standard, the Company could be found to be in violation of a NERC reliability standard requirement.

Q. WHAT ARE THE KEY RELIABILITY REQUIREMENT PROJECTS THAT TRANSMISSION WILL PLACE IN-SERVICE DURING THE MYRP PERIOD?

A. The key Reliability Requirement projects and programs that will be placed in-service in 2022 through 2024 are:

- Bayfield Loop Project,
- South Washington Electric Reliability,
- Jim Falls – Holcombe,
- Hurley Norrie 115 kV,
- TACT program,
- Elm Creek TR10,
- Western Wisconsin/E. Metro Upgrade,
- Elmwood Substation,

- Long Lake Baytown Ln0801 Uprate,
- Bayfront to Ironwood 88 kV, and
- Rogers Lake 115 kV Bus Expansion.

Q. PLEASE DESCRIBE THE BAYFIELD LOOP PROJECT.

A. The Bayfield Loop Project, which is also referred to as the Bayfield Second Circuit Transmission Project, is needed to improve system reliability by adding redundancy to the system by constructing a second 34.5 kV transmission line and two new substations in the Bayfield Peninsula area of Wisconsin. The proposed new transmission line would extend approximately 19 miles, and would connect the two new substations: the Fish Creek Substation, located approximately four miles west of Ashland, Wisconsin, and Pikes Creek Substation, located approximately two miles west of Bayfield, Wisconsin.[5] The project will increase electric reliability and reduce power outages across the Bayfield Peninsula by providing voltage support and a second source of power to the east side of the Bayfield Peninsula. The proposed 34.5 kV transmission line is called the "second circuit" or "second source" because there is an existing 34.5 kV line extending to Bayfield. The Public Service Commission of Wisconsin granted a Certificate of Authority for the Bayfield Loop Project on February 7, 2020.[6]

Grading for the new Fish Creek Substation began in 2020 and construction of the Pikes Creek Substation and the transmission line are planned to commence

[5] *Application of N. States Power Co.-Wisc. for a Certificate of Auth. to Construct the Bayfield Second Circuit Transmission Project, to be Located in Bayfield Cnty., Wisc.*, PSCW Docket No. 4220-CE-182, APPLICATION FOR A CERTIFICATE OF AUTHORITY (Mar. 8, 2019).

[6] *Application of N. States Power Co.-Wisc. for a Certificate of Auth. to Construct the Bayfield Second Circuit Transmission Project, to be Located in Bayfield Cnty., Wisc.*, PSCW Docket No. 4220-CE-182, FINAL DECISION (Feb. 7, 2020).

in 2021. This project is currently scheduled to be placed in service in 2022. The project has total plant additions of approximately $44.7 million ($44.0 million in 2022 and $0.7 million in 2023).

Q. PLEASE DESCRIBE THE SOUTH WASHINGTON ELECTRIC RELIABILITY PROJECT.

A. This project involves replacing and upgrading key pieces of substation equipment at the Red Rock Substation in Newport, Minnesota. For instance, Transmission will replace the existing 48VDC battery system with a new 125VDC battery system. This replacement is needed to comply with FERC Order 754 which requires substation owners to identify and address deficiencies in their protection and control systems that could pose a risk to the backup response in case a failure occurs. This includes eliminating opportunities for a single point of failure across multiple breakers. This project is currently scheduled to be placed in service in 2024. The project has total plant additions of approximately $13.2 million ($0.5 million in 2023; and $12.8 million in 2024).

Q. PLEASE DESCRIBE THE JIM FALLS – HOLCOMBE PROJECT.

A. This project involves rebuilding approximately 15 miles of the Jim Falls – Holcombe 115 kV transmission that is located north of Eau Claire, Wisconsin. As part of this rebuild, this conductor will be replaced with a higher capacity conductor and the structures will be built to be double-circuit capable. This project is needed to address line overloads under certain contingencies. This project is currently scheduled to be placed in service in 2024 with total plant additions of approximately $10.9 million.

Q. PLEASE DESCRIBE THE HURLEY NORRIE 115 KV PROJECT.

A. This project involves the construction of a new 3-mile 115 kV transmission from the Hurley Substation in Wisconsin to the Norrie Substation in Ironwood, Michigan. This project also includes substation upgrades at the existing Hurley and Norrie substations. This project is needed to alleviate transient voltage issues under certain contingencies conditions. This project is currently scheduled to be placed in service in 2024 with total plant additions of approximately $10.7 million ($10.6 million in 2023 and $0.1 million in 2024).

Q. PLEASE DESCRIBE THE TACT PROGRAM.

A. NERC requires utilities to perform annual assessments of their transmission system and to demonstrate plans to keep the transmission system within specified voltage, thermal, and stability limits throughout the 10-year planning period. The Company performs this annual assessment by participating in the MISO MTEP process, which is an RTO-led reliability study effort. MISO MTEP participants work together to analyze the transmission system for deficiencies (high voltage, low voltage, lines or transformers beyond their rated capability, etc.) and to ensure compliance with the NERC TPL-001-4 reliability standard. Generally speaking, the NERC TPL-001-4 reliability standard requires that transmission systems be designed and constructed to operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies such as loss of one or more elements of the system. The MISO MTEP studies the performance of the system using 1-year, 5-year, and 10-year future models. When deficiencies are identified, MISO transmission owners create a plan to manage the transmission system to stay within the specified limits. The MISO MTEP typically finalizes its annual study in December of each year.

The Company established the TACT program to allocate resources necessary to address reliability issues on the NSP Transmission System that are identified in the annual MISO MTEP studies.

For both NSPM and NSPW the TACT program has total plant additions of approximately $9.5 million ($1.0 million in 2022; $5.0 million in 2023; $3.5 million in 2024).

Q. PLEASE DESCRIBE THE ELM CREEK TR10 UPRATE PROJECT.

A. This project will install a new 345/115/34.5 kV, 448 MVA transformer at the Elm Creek Substation in Maple Grove, Minnesota. As part of this project, Transmission will also connect the existing 345 kV Sherburne County – Coon Creek 345 kV line to the Elm Creek Substation and expand the existing 345 kV "in and out" configuration to a six-position ring bus. This project is needed to provide additional load serving capability in this fast-growing portion of the metro. This project is currently scheduled to be placed in service in 2023 with total plant additions of approximately $9.3 million.

Q. PLEASE DESCRIBE THE WESTERN WI/E. METRO UPGRADE PROJECT.

A. This project involves replacing the existing transformer at the existing Pine Lake Substation in Prior Lake, Minnesota and adding a capacitor bank at the existing Willow River Substation in Hudson, Wisconsin. These upgrades are needed to address thermal overload conditions that result from the loss of the 345/115 kV transformer at the A.S. King Substation in Bayport, Minnesota as well as a 115 kV line in the area. This project is currently scheduled to be placed in service in 2024 with total plant additions of approximately $7.4 million.

Q. PLEASE DESCRIBE THE ELMWOOD SUBSTATION PROJECT.

A. This project involves the construction of a new substation, the Elmwood Substation, in Elmwood, Wisconsin. This new substation will be built to accommodate three new transmission line terminations. This project is needed to provide additional redundancy and reduce outage exposure to provide greater reliability in this area. This project is currently scheduled to be placed in service in 2022 with total plant additions of approximately $6.5 million.

Q. PLEASE DESCRIBE THE LONG LAKE BAYTOWN LINE 0801 UPRATE PROJECT.

A. This project involves installing new 115 kV conductor on the existing double circuit capable structures of the Baytown – Long Lake 115 kV line. As part of this project, Transmission will install new OPGW shield wire on this line. This project is needed to address overload conditions on the Long Lake – Baytown 115 kV line that occur when there is a loss of the 345/115 kV transformer at A.S. King Substation in Bayport, Minnesota and the loss of the Red Rock – Afton 115 kV line. This project is currently scheduled to be placed in service in 2022 with total plant additions of approximately $4.9 million.

Q. PLEASE DESCRIBE THE BAYFRONT TO IRONWOOD PROJECT.

A. This project includes the purchase of land rights that are needed for the relocation of the Company's 88 kV W3351 line located on the Bad River Indian Reservation in Northern Wisconsin. Construction of this relocation project will not begin until 2023 and is planned to be placed in-service in 2028. During the term of this MYRP, $4.8 million in land rights will be placed in service to accommodate this planned relocation ($2.5 million in 2022 and $2.2 million in 2023).

Q. PLEASE DESCRIBE THE ROGERS LAKE 115 KV BUS EXPANSION PROJECT.

A. This project involves expanding and reconfiguring the current Rogers Lake Substation in Mendota Heights, Minnesota. Specifically, this project includes terminating the existing double-circuit 115/115 kV transmission line from the Highbridge Substation into two separate substation bays and relocating the Airport – East Bloomington 115 kV line into a new breaker and a half scheme at this substation. This project is needed to provide additional system area reliability and resiliency to this substation. This project is currently scheduled to be placed in service in 2022 with total plant additions of approximately $4.7 million.

3. Communication Infrastructure Projects

Q. WHY ARE INVESTMENTS IN COMMUNICATION INFRASTRUCTURE NECESSARY?

A. Communication circuits are required at substations for SCADA, remote engineering access, and teleprotection. In the past, the Company has relied on third-party telecommunication providers for the infrastructure necessary for our SCADA and teleprotection circuits (*i.e.*, communication circuits between our substations and between our substations and our control center). However, many of the telecommunication companies are phasing out their dedicated analog wide area network (WAN) technology and replacing it with Ethernet over fiber optics or other broadband services. These new services, while capable of carrying large volumes of data, are not able to carry the data that we transmit within acceptable performance requirements for the teleprotection of our transmission system. As a result, we need to invest in Company-owned and controlled communication infrastructure using fiber optic cable that will serve our operational and system protection needs without the reliance on and vulnerability to exposure from a publicly available third-party network.

Similarly, cyberattacks pose a credible threat to the reliability of our transmission system as hackers could cause system outages by disabling telecommunications or key pieces of equipment. Every day there are coordinated attempts to infiltrate communication systems and disrupt the transmission grid. Federal regulatory agencies have responded to these growing threats by adopting cybersecurity standards for transmission facilities. The Company-owned telecommunications network we are investing in enables the Company to reduce our exposure to cybersecurity threats from the publicly available service provided by third-party telecommunication providers.

Q. DO THESE INVESTMENTS PROVIDE ANY OTHER BENEFITS?

A. Yes, an additional benefit of these investments is that they will also support the Advanced Grid and Information System (AGIS) initiative and enterprise-wide initiatives by enabling connectivity between all of our substations and corporate offices.

Q. WHAT ARE THE KEY COMMUNICATION INFRASTRUCTURE PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN-SERVICE DURING THE MYRP PERIOD?

A. The key Communication Infrastructure projects that will be placed in service between 2022 and 2024 will arise out of the Communication Network program.

Q. DESCRIBE THE COMMUNICATIONS NETWORK PROGRAM.

A. The Communication Network program aims to privatize Xcel Energy's communication network infrastructure across the NSPM and NSPW service territories, wherever possible, at all transmission and distribution substations for SCADA, teleprotection, and remote engineering access. Specifically, the program addresses aging analog circuit technology and other technology that is anticipated to become obsolete within five years. The Company will then build secure communication architecture for physically isolated operational technology (OT) and information technology (IT) networks from each other to support islanding of the energy management system (EMS) for further cyber security resilience. The program will enable the Company to reduce dependency on third-party circuit providers, which will improve the Company's troubleshooting response time and reduce circuit down time.

The Company has budgeted $80.9 million for the NSPM Communication Network program ($31.0 million in 2022; $24.3 million in 2023; and $25.6 million in 2024). The Company has budgeted $47.8 million for the NSPW Communication Network program ($16.9 million in 2022; $14.9 million in 2023; and $16.0 million in 2024).

Q. CAN YOU PROVIDE AN EXAMPLE OF ONE OF THESE COMMUNICATION NETWORK PROJECTS?

A. Yes, one example is the installation of approximately 17 miles of OPGW between the Company's Ellsworth Area Substation and Prescott Substation in western Wisconsin. Another is at Company's Red Rock Substation in Newport, Minnesota, where we will be installing upgraded telecommunication equipment and installing a private communication network path (fiber optic cable) from the substation to a leased fiber optic cable located outside the substation that will only be utilized by the Company for communication within our network.

Q. HOW DID THE COMPANY DEVELOP THE BUDGETS FOR THE COMMUNICATIONS NETWORK PROGRAM?

A. The budget is based on Communication Network infrastructure projects identified and prioritized by our substation communication engineering group for consideration in the capital budget. Communication projects are prioritized based on technical need and proximity to exiting private network infrastructure that is deliberately built out from a reliable core network. These projects are vetted and prioritized against all Transmission projects; and rebalanced and reprioritized across the entire portfolio of projects based on corporate budget requirements. Project costs are estimated using historic costs from prior projects.

4. *Physical Security and Resiliency Projects*

Q. WHAT ARE THE MAJOR ISSUES FACING TRANSMISSION WITH REGARD TO PHYSICAL SECURITY AND RESILIENCY?

A. Transmission is focused on maintaining the security of our assets. High voltage transformers comprise less than 3 percent of transformers in U.S. electric power substations, but they carry 60 to 70 percent of the nation's electric load. Since they serve as vital nodes and carry bulk volumes of electricity, these transformers are critical elements of the nation's electric power grid. They are also the most vulnerable to intentional damage from malicious acts. In April 2013, for example, a substation in California was subject to a coordinated military-type sniper attack that disabled 17 high voltage transformers, rendering this substation useless.

Federal regulatory agencies have since responded to these growing threats by adopting physical security standards for transmission facilities. On March 7, 2014, FERC issued an Order on Reliability Standards for Physical Security Measures, which ultimately led to NERC CIP-014 addressing risks due to physical security threats and vulnerabilities. To address these threats and meet this NERC standard, we are making necessary investments to make our grid more resilient so that we can respond quickly to physical security threats.

Q. WHAT ARE THE KEY PHYSICAL SECURITY AND RESILIENCY PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN-SERVICE DURING THE MYRP PERIOD?

A. The Physical Security and Resiliency projects that will be placed in-service between 2022 and 2024 will arise out of two programs: (1) the NSPM/NSPW Physical Security program and (2) the NERC Circuit Protection program.

Q. PLEASE DESCRIBE THE NSPM/NSPW PHYSICAL SECURITY PROGRAM.

A. The NSPM/NSPW Physical Security program was developed to ensure the Company's compliance with NERC CIP-014. Additionally, the program aims to improve substation site security where the Company's Protection Services department has identified ongoing theft issues. The purpose of this program is to improve the physical security of the Company's substations. The Company is developing site-specific security plans for specific substations and is obtaining third-party verification of the effectiveness of these plans. These site-specific security plans may include the following security measures: cameras, fencing/barrier improvements, ballistic shielding of identified key substation equipment, site access controls, ground sensory monitoring, and radar technology. This program is planned for 36 discrete substation sites in 2022 and 2023; additional sites will be identified and evaluated against the most current NERC security standards for inclusion in this program as the risk assessments are updated every two years in accordance with NERC CIP-014.

The Company has budgeted $84.8 million for the Physical Security program over the term of the MYRP ($37.8 million in 2022; $30.8 million in 2023; and $16.2 million in 2024).

Q. HOW DID THE COMPANY DEVELOP THE BUDGET FOR THE PHYSICAL SECURITY PROGRAM?

A. Our Substation Compliance team and our Protection Services department have identified sites that are highly likely to either a) need to be brought up to NERC CIP-014 requirements or b) have been targets of ongoing theft. As changes to the transmission system regularly occur, those changes may impact a substation location that was not previously required to have the physical security controls as defined under NERC CIP-014. This is because whether or not security controls are required under NERC CIP-014 is dependent on the impact the loss of that substation may have on the bulk electric system. As new transmission projects come forward, Xcel Energy reviews the associated impacted substations to determine whether these locations must now meet the heightened physical security requirements outlined in NERC CIP-014. A similar reevaluation is performed for sites that have been a target of theft.

The budget for each of the identified sites are estimated at a high level based on existing as-built and record drawings. Each site is then prioritized within the program based on the level of protection required to bring it up to NERC CIP-014 or discourage theft. Each site requires an on-site evaluation by the project team to validate the existing conditions, determine if there are other site conditions that were not identified in the record drawings and update/validate the estimate. This site evaluation is typically done in the year prior to the specific site's in-service date.

Q. DOES TRANSMISSION'S BUDGET FOR ITS PHYSICAL SECURITY PROGRAM INCLUDE ANY ACCELERATED WORK ASSOCIATED WITH THE COVID-19 RELIEF & RECOVERY DOCKET?

A. Yes. Table 12 below outlines the Physical Security projects that will be accelerated and in-serviced in 2021, 2022, 2023, and 2024. Consistent with the Commission's March 12, 2021 Order,[7] the Company has been tracking its spending related to these COVID-19 Relief & Recovery projects and the Company has been providing this information to the Commission as part of its quarterly compliance filings in that docket.[8]

Table 12
NSPM Physical Security Projects for COVID-19 Relief & Recovery Capital Additions
($ millions)

Project Name	2021 Forecast	2022 Budget	2023 Budget	2024 Budget
Physical Security program	$22.2	$32.9	$28.6	$13.8

[7] *In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery form the COVID-19 Pandemic*, ORDER DETERMINING THAT PROPOSALS HAVE THE POTENTIAL TO BE CONSISTENT WITH COVID-19 ECONOMIC RECOVERY, Docket No. E,G999/CI-20-492 (March 12, 2021).

[8] *In the Matter of an Inquiry into Utility Investments that May Assist in Minnesota's Economic Recovery form the COVID-19 Pandemic*, 2021 SECOND QUARTER REPORT COVID-19 RELIEF & RECOVERY, Docket No. E,G999/CI-20-492 (July 30, 2021).

Q. HOW DO CUSTOMERS BENEFIT FROM THE ACCELERATION OF THESE PHYSICAL SECURITY PROJECTS?

A. Our Physical Security projects improve security at the Company's substations. By accelerating these security projects, customers will see benefits in terms of improved security measures at more substation locations. Substations are essential to a reliable transmission system and these security projects will prevent theft and unauthorized access to these sites. Acceleration of these projects will also ensure the Company's compliance with NERC CIP-014.

Q. PLEASE DESCRIBE THE NERC CIRCUIT PROTECTION PROGRAM.

A. The NERC Circuit Protection program was initiated to comply with FERC Order 754. Under FERC Order 754, the Company must identify single point failures at critical substations with voltages of 200 kV or above and report the results to NERC. The Company has studied the relevant substations and identified certain required modifications to eliminate these single point failures. This program includes capital projects related to separating primary and secondary relaying and adding redundant direct current circuits at several Company-owned substation facilities. This separation allows a back-up battery to continue to provide protection services in the case the primary battery at the substation fails.

The Company has budgeted $10.7 million for the NERC Circuit Protection program ($2.3 million in 2022; and $8.3 million in 2022). Under FERC Order 754, substation owners must identify and address deficiencies in their protection and control systems that could pose a risk to the backup response in case a failure occurs. This includes eliminating opportunities for a single point of failure across multiple breakers. FERC Order 754 requires compliance by 2024 so Transmission started this work in 2017 and will ramp up this work in 2022 and 2023 to ensure that we complete all required work prior to 2024.

Q. CAN YOU PROVIDE AN EXAMPLE OF A PROJECT WITHIN THE NERC CIRCUIT PROTECTION PROGRAM?

A. One of the projects that the Company will be completing to comply with FERC Order 754 is at the Chisago Substation where the Company will be adding auxiliary relays to trip the breakers of other transformers in the event that a failure occurs on another substation breaker. This improvement will ensure compliance with FERC Order 754 and will improve the reliability of the Chisago Substation. This project will be in service in 2023 and has associated capital additions of $2.4 million.

5. Interconnection Projects

Q. WHAT IS DRIVING TRANSMISSION'S INTERCONNECTION INVESTMENTS?

A. Under our tariff, we are required to make the necessary transmission upgrades to accommodate interconnection requests. There are three general types of Interconnection projects that drive our interconnection investments: transmission interconnections, load interconnections, and generation interconnections. Transmission interconnections are where one utility is requesting to interconnect a transmission line to our transmission system. Load interconnections are where a new substation serving electric load is needed and is requesting to interconnect to our transmission system, or an existing load serving substation is being modified. Generation interconnections are where a new generator is requesting to interconnect to our transmission system.

Q. WHAT IS DRIVING THE INCREASE IN INTERCONNECTION PROJECTS IN 2022 THROUGH 2024?

A. The increase in Interconnection projects is driven primarily by the number of interconnection requests currently pending in the MISO queue. These new generation facilities require certain transmission upgrades in order to interconnect to the transmission system, and as a result, the Company is making increasing investments to complete these necessary upgrades.

Q. WHAT ARE THE KEY INTERCONNECTION PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN-SERVICE DURING THE MYRP PERIOD?

A. From 2022 through 2024, the key Interconnection programs/projects are: (1) NSPM/NSPW self-funded network upgrade (SFNU) projects; (2) Interconnection Agreement (IA) Tariff Fund Program; and (3) Sherco Solar Substation Interconnection Upgrade.

Q. PLEASE DESCRIBE THE NSPM/NSPW SFNU PROJECTS.

A. The SFNU are a group of projects to support network upgrades necessary to accommodate generation interconnections. Specifically, network upgrades are defined as the additions, modifications, and upgrades to the transmission system that are required at or beyond the point at which the generation interconnection facilities connect to the transmission system. Generally, these network upgrades are either new facilities, such as transmission lines or substations, or occasionally modifications and/or additions to existing transmission substations or to transmission lines connecting to an existing substation.

Q. WHY ARE THE COSTS FOR THESE SFNU PROJECTS INCLUDED IN THIS RATE CASE RATHER THAN BEING RECOVERED FROM THE INTERCONNECTION CUSTOMERS?

A. The MISO tariff allows transmission owners like Xcel Energy the option to unilaterally choose to self-fund network upgrades without requiring interconnection customers to make upfront payments for these upgrades. Prior to the in-service date of the network upgrades, Xcel Energy will enter into a Facilities Service Agreement (FSA) with the interconnection customer to repay the actual cost for the network upgrade that allows Xcel Energy to earn a return, typically over a period of twenty (20) years, with payments beginning the month after the network upgrades are placed into service. Xcel Energy has decided to exercise the self-funding option for all network upgrades associated with MISO generation interconnection projects. The payments that will be made by generators in accord with these FSAs over the term of the MYRP are included in the transmission revenues budget in this case, which reduce the retail revenue requirement and keep retail customers whole. As such, these Interconnection projects essentially pay for themselves, although the timing of these reimbursements may differ depending on the project.

Q. WHAT IS THE BUDGET FOR SFNU PROJECTS OVER THE TERM OF THE MYRP?

A. The Company has budgeted $22.2 million for the NSPM SFNU Project ($0.4 million in 2022; $5.6 million in 2023; and $16.2 million in 2024). The Company has budgeted $3.8 million for the NSPW SFNU Project ($0.03 million in 2022; $0.7 million in 2023; and $3.0 million in 2024).

Q. HOW DID THE COMPANY DEVELOP THE BUDGET FOR THE NSPM/NSPW SFNU PROJECTS?

A. Currently, there are approximately 25 renewable generation interconnection projects in the MISO queue that will require network upgrades to accommodate their interconnection to the MISO transmission system. The budget for these potential projects is developed by a facilities study performed by Xcel Energy engineers at the request of MISO. These facilities studies include high-level cost estimates of the potential network upgrades required based on general location of the renewable generation source and proposed output of the renewable generation. We relied on the cost estimates from these facilities studies to develop the budget for the NSPM/NSPW SFNU projects.

Q. PLEASE DESCRIBE THE IA TARIFF FUND PROGRAM.

A. This program is used to fund generation interconnection related transmission capital investments. The specific transmission upgrades in this program have not yet reached the level of specificity to be defined as specific capital projects but nonetheless are expected based on generator's announced plans or interconnection requests in the MISO queue. The Company has budgeted $13.4 million for the NSPM IA Tariff Fund Program ($5.3 million in 2022; $4.0 million in 2023; and $4.0 million in 2024). The Company has budgeted $8.7 million for the NSPW IA Tariff Fund ($2.6 million in 2022; $3.0 million in 2023; and $3.1 million in 2024).

Q. CAN YOU PROVIDE AN EXAMPLE OF A PROJECT WITHIN THE IA TARIFF FUND PROGRAM?

A. One example is our Arkansaw Tap Interconnection project. This project is needed because Dairyland Power Cooperative is retiring a section of their N-5 line, which is currently interconnected to the Company's Arkansaw Substation. To prevent our Arkansaw Substation from being served by a radial 69 kV line, we plan to acquire a section of Dairyland's 69 kV and rebuild it to provide an additional source to this substation. This new tap line will provide a backup source to the Arkansaw Substation for maintenance and unplanned system outages. This project will be placed in service in 2022 and has plant additions of $0.9 million.

Q. HOW DID THE COMPANY DEVELOP THE BUDGET FOR THE IA TARIFF FUND PROGRAM?

A. As noted above, the budget for this program is based on historical averages and known Interconnection project requests.

Q. PLEASE DESCRIBE THE SHERCO SOLAR SUBSTATION INTERCONNECTION UPGRADE PROJECT.

A. The Sherco Solar Substation Interconnection project is needed to interconnect the Company's proposed 460 MW Sherco Solar Project, that is currently pending before the Commission, to the Sherburne County Substation. The Sherco Solar Project is being proposed by the Company to partially replace the energy generation of the Sherco Unit 2 coal generating facility, which will cease operations by the end of 2023. This interconnection project will require construction of two collector substations near the solar facility and two 345 kV generation-tie (gen-tie) lines, which will connect the collector substations to the point of interconnection at the existing Sherburne County Substation. This project is currently scheduled to be placed in service in 2024. The project has total plant additions of approximately $4.9 million during the term of this MYRP ($4.2 million in 2023 and $0.7 million in 2024). The Company plans to seek recovery for the Sherco Solar Project through the Renewable Energy Standard (RES) Rider should the project be approved by the Commission.

6. Regional Expansion Projects

Q. WHAT ARE THE KEY REGIONAL EXPANSION PROJECTS THAT TRANSMISSION ANTICIPATES PLACING IN SERVICE DURING THE MYRP PERIOD?

A. There is one key Regional Expansion projects that will be placed in-service between 2022 and 2024 – the Google Data Center Project.

Q. DESCRIBE THE GOOGLE DATA CENTER PROJECT.

A. The Company has negotiated several agreements with Honeycrisp, LLC, an affiliate of Google LLC, that are intended to help bring a new data center to the City of Becker, Minnesota. If the project moves forward, it could generate $600 million in capital investment and presents an opportunity to be one of the largest private economic development endeavors in central Minnesota. To facilitate the development of the possible new data center, the Company sought and received approval from the Commission for several agreements, associated cost recovery, and certain tariff amendments and waivers that would enable the Company to provide retail electric service at transmission voltage to the possible new data center.[9]

Among the several agreements, the Company executed an IA for Retail Electric Service at Transmission Voltage, which provides the terms and conditions for the Company's build-out of certain transmission voltage facilities to support interconnection of the data center. The IA provides different transmission

[9] *In the Matter of the Pet. by N. States Power Co. d/b/a Xcel Energy for Approval of Contracts and Ratemaking Treatment for Provision of Elec. Serv. to Google's Data Center Project*, Docket Nos. E002/M-19-39 and E002/M-19-60, ORDER APPROVING PETITION WITH CONDITIONS (July 15, 2019).

voltage configurations to support varying amounts of data center load in line with the customer's issuance to the Company of a "Notice to Proceed," after which the Company is obligated to construct the necessary facilities at its cost. Should the IA be terminated prior to the conclusion of the 10-year IA period, Honeycrisp, LLC would make a termination payment to the Company equivalent to the net book value of the transmission facilities as of the date of termination.

The Company also requested and received approval of a one-time waiver from the Company's General Time-of-Day Service Tariff requiring that a customer bear the cost of interconnection upgrades required to serve the customer. Rather than recover these costs directly from Honeycrisp, LLC via a contribution in aid of construction (CIAC), the Company requested – and the Commission granted – authorization to seek recovery of these costs in a future rate case.[10] The project has forecasted total plant additions of approximately $16.3 million ($1.7 million in 2022 and $13.6 million in 2024).

Q. WHY IS THE DATA CENTER PROJECT CLASSIFIED AS A REGIONAL EXPANSION PROJECT?

A. In addition to large regional infrastructure, our Regional Expansion projects also include those projects driven by economic development needs, which is the primary driver for the Data Center project.

[10] *Id.* at 23.

Q. WHAT DO YOU CONCLUDE WITH RESPECT TO THE OVERALL LEVEL OF TRANSMISSION CAPITAL COSTS THE COMPANY IS SEEKING TO RECOVER IN THIS RATE CASE?

A. I conclude that our capital forecasts represent an accurate and reasonable projection of our investments over these years and, as shown by the above discussion, are necessary to provide reliable and resilient transmission service for our customers. Finally, the costs included in our 2022 through 2024 capital budgets are representative of the types of work we must and will do year over year. Therefore, these capital forecasts can be relied on to set just and reasonable rates for our customers.

IV. O&M BUDGET

A. O&M Overview and Trends

Q. WHAT IS INCLUDED IN THE TRANSMISSION O&M BUDGET?

A. The Transmission O&M budget includes costs associated with the operation and maintenance of our transmission system. This includes internal and contract labor, employee expenses, fees, and materials. The majority of Transmission's O&M budget is related to internal labor costs as these employees are necessary to plan, construct, operate, and maintain the transmission system on a daily basis.

Q. WHAT ARE THE TRANSMISSION O&M BUDGET CATEGORIES?

A. The Transmission business unit O&M budget consists of six main cost categories: (1) internal labor; (2) contract labor and consulting; (3) employee expenses; (4) fees; (5) materials; and (6) other. I describe these categories in detail later in my testimony.

Q. HOW ARE THE TRANSMISSION BUSINESS UNIT LONG-TERM O&M COSTS TRENDING?

A. From 2018 to 2020, the Transmission business unit has engaged in productivity improvement initiatives, which have reduced O&M expenses over these years. These efforts include improved scheduling and field productivity that have resulted in more efficient and effective ways for Transmission crews to schedule and complete their work, thus reducing O&M expenditures. Additionally, the Company has improved its repair versus replacement decision-making to promote replacement over repair for assets that required repeated costly repairs. These initiatives, and the resulting reductions in O&M expense, have offset ongoing inflationary pressures. Some examples of the efforts that led to the increased efficiency include locking in work schedules a week prior, more detailed scheduling, formalized job readiness checklists, minimization of schedule changes, and daily huddles with leadership and crews to discuss daily work plans.

Q. WHAT IS TRANSMISSION'S O&M FORECAST FOR 2021?

A. Transmission's forecasted O&M for 2021 is $30.8 million which is lower than our historical actuals for 2018 to 2020. Transmission's 2021 O&M is lower due to continued efficiencies and on-going impacts from the COVID-19 pandemic. In response to the impact that COVID-19 had on our communities, customers, and operations in 2020, Transmission adjusted our operations to maintain financial flexibility as the Company faced uncertainties about the depth and duration of the impacts of COVID-19. Specifically, Transmission reduced O&M expenses in 2020 by reducing contractor hours, reducing employee travel, delaying hiring open positions, and scaling back on overtime, where possible without impacting safety and reliability. Some of these reductions due to COVID-19 have continued into 2021.

Q. WHAT ARE THE TRANSMISSION O&M BUDGETS FOR 2022 TO 2024?

A. As shown in Table 13, we have budgeted $31.6 million for Transmission O&M in 2022, $32.2 million in 2023, and $32.8 million in 2024. Table 10 also provides our actual O&M costs for 2018 to 2020 and the 2021 forecast for O&M spend (half year actuals and half year forecast). Table 14 provides this same information but allocated to the State of Minnesota Electric Jurisdiction. Exhibit___(IRB), Schedule 4 also provides the Transmission O&M costs by cost category for 2018 to 2020.

Table 13

Transmission O&M Budget by Cost Category

NSPM-Electric

($000,000)

Cost Category	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Budget**	**2023 Budget**	**2024 Budget**
Internal Labor	$22.0	$20.4	$18.1	$18.1	$18.8	$19.4	$20.0
Contract Labor and Consulting	$4.5	$4.5	$4.1	$3.8	$3.5	$3.5	$3.5
Employee Expenses	$2.9	$2.7	$1.8	$1.8	$2.0	$2.0	$2.0
Fees*	$3.5	$3.4	$3.5	$3.6	$3.6	$3.6	$3.6
Materials	$3.3	$2.5	$2.1	$1.8	$2.3	$2.3	$2.3
Other	$4.1	$2.6	$1.2	$1.7	$1.4	$1.4	$1.4
Total	**$40.3**	**$36.1**	**$30.8**	**$30.8**	**$31.6**	**$32.2**	**$32.8**

Table 14

Transmission O&M Budget by Cost Category

State of Minnesota Electric Jurisdiction

(New of Interchange Billings to NSPW)

($000,000)

Cost Category	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2021 Forecast**	**2022 Budget**	**2023 Budget**	**2024 Budget**
Internal Labor	$16.2	$14.9	$13.2	$13.2	$13.7	$14.2	$14.6
Contract Labor and Consulting	$3.3	$3.3	$3.0	$2.8	$2.6	$2.5	$2.5
Employee Expenses	$2.2	$2.0	$1.3	$1.3	$1.5	$1.5	$1.5
Fees*	$2.6	$2.5	$2.5	$2.6	$2.6	$2.6	$2.6
Materials	$2.5	$1.8	$1.5	$1.3	$1.6	$1.6	$1.6
Other	$3.0	$1.9	$0.9	$1.2	$1.0	$1.0	$1.0
Total	**$29.9**	**$26.4**	**$22.5**	**$22.4**	**$23.1**	**$23.5**	**$23.9**

Q. DO TRANSMISSION'S O&M EXPENSES FOR 2022 TO 2024 CONTINUE THIS DECLINING TREND FROM 2018 TO 2020?

A. Yes. The Transmission O&M budget for 2022 to 2024 trends lower than 2018 to 2020 actuals. This continued decrease is primarily driven by productivity improvement initiatives that have been implemented by Transmission that I discussed earlier. These decreases are partially offset by base pay increases for internal labor in 2022 to 2024.

Q. HOW DOES THE TRANSMISSION O&M BUDGET FOR 2022 TO 2024 COMPARE TO 2020 ACTUALS?

A. Transmission's O&M budget for 2022 is less than 2020 actuals by 3 percent whereas 2023 and 2024 budgets are higher than 2020 actuals by an average of 6 percent. The overall increase from 2020 actuals to the 2022 to 2024 O&M

budget is driven by increases in base pay for internal labor and employee expenses.

Q. WHAT IS DRIVING THE INCREASE IN BASE PAY DURING THE TERM OF THE MYRP?

A. Transmission has budgeted a 3 percent annual increase in base pay for employees. Annual base pay increases are discussed in greater detail by Company witness Ms. Ruth K. Lowenthal.

Q. ARE THERE ANY OTHER REASONS WHY THE TRANSMISSION O&M BUDGET FOR 2022 IS HIGHER THAN 2020 ACTUAL O&M EXPENSES?

A. Employee expenses are assumed to increase by $0.2 million due to a partial return to normal training and travel as compared to 2020. In addition, the Operational Technology (OT) Security program will drive an additional $0.6 million increase costs. The OT Security program provides cyber-security to Company assets. Efforts will include Security Monitoring and Logging, Vulnerability and Patch Management, and Information Management/Password Management and Asset Management. This program is an extension of the work that we perform today for the NERC CIP Medium Impact Rated Assets across a broader asset base. A portion of these increases have been offset by productivity improvement initiatives that have been implemented by Transmission. Table 15 summarizes the impacts of these items on Transmission's O&M budget.

Table 15

Transmission 2022-2024 Budget vs. 2020 Actual O&M Expenditures

NSPM-Electric

(Dollars in Millions)

Cost Drivers	Amount of Increase/Decrease	Total
2020 Actual		**$30.7**
Base Pay	$1.1	
OT Security	$0.6	
Employee Expenses	$0.2	
Continuous Improvements	($1.0)	
2022 Budget		**$31.6**
Base Pay	$0.6	
2023 Budget		**$32.2**
Base Pay	$0.6	
2024 Budget		**$32.8**

Q. How do the 2022 to 2024 O&M budgets compare with the 2021 forecast?

A. Transmission's O&M budget for each of these three years is higher than the 2021 forecast by an average of 2 percent. The overall increase from the 2021 forecast to the 2022 to 2024 O&M budget is driven by increases in: 1) base pay; 2) employee expenses; and 3) OT Security program.

Q. How does the 2023 O&M budget compare to the 2022 budget?

A. The 2023 O&M budget is 2 percent higher than the 2022 budget. This is due to the annual increases in base pay.

Q. HOW DOES THE 2024 O&M BUDGET COMPARE TO THE 2023 BUDGET?

A. The 2024 O&M budget is 2 percent higher than the 2023 budget. This is due to the annual increase in base pay.

B. O&M Budgeting Process

Q. HOW DOES THE COMPANY SET THE O&M BUDGET FOR THE TRANSMISSION BUSINESS UNIT?

A. As with our capital budget, the O&M budget for the Transmission business unit is built using a bottom-up approach. Each budget manager reviews their needs, factoring in work plans as well as any anticipated efficiency gains for the coming years, and develops budgets in accordance with those needs and anticipated efficiency improvements. As part of this bottom-up process, the field operations and construction units review those facilities that need repairs to extend their asset life, addressing issues like broken insulators, loose hardware, woodpecker damage, broken or damaged guy wires, etc. In this way, Asset Renewal projects are a driver of the O&M budgeting process. The individual manager budgets are then consolidated for a total Transmission O&M budget and analyzed for reasonableness and accuracy as compared to recent actual trends. This process includes normalizing the actual spend for those expenses that are not expected to continue into the budget year due to changes in business conditions or one-time events. The total Transmission business unit budget is compared to the overall Company targets, which are discussed further in Ms. Ostrom's Direct Testimony. If the budget is greater than the overall Company targets provided to Transmission, the needs are prioritized with the most critical needs funded first and the least critical needs funded last.

Q. PLEASE EXPLAIN HOW TRANSMISSION MONITORS ITS O&M EXPENDITURES.

A. The Transmission business unit is supported by a dedicated finance team. The finance team prepares monthly reporting for the Transmission business unit that includes reviews of the current month actual versus budget, year-to-date actual versus budget, and year-end forecast versus target. This reporting is reviewed on a monthly basis with the Transmission leadership team, where concerns or issues are also discussed.

Q. HOW DOES THE TRANSMISSION BUSINESS UNIT O&M BUDGET PROCESS AND GOVERNANCE COMPARE TO INDUSTRY PRACTICE?

A. The process the Transmission business unit uses in the development of the O&M budget is consistent with the practices used in the other business units across the Company. As discussed above, the budget development is accomplished through a bottom-up approach where each budget manager develops their budget based on identified work plans and efficiency gains for the budget year and prioritized based on the most critical activities to ensure the Company targets are met. During the year, governance is accomplished through the monthly reporting and monitoring of performance as well as formal tracking of changes to the year-end targets by director within an operating company, as discussed above. Any changes to the year-end targets within the Transmission business unit are approved by the Senior Vice President of Transmission. Any changes to the overall Transmission business unit targets are brought forward to senior management for consideration. Further discussion of the overall Company budget process and governance is discussed in the Direct Testimony of Ms. Ostrom.

C. O&M Budget Detail

1. Internal Labor

Q. WHAT INTERNAL LABOR COSTS ARE INCLUDED IN THE TRANSMISSION BUSINESS UNIT'S O&M BUDGET?

A. This category represents the O&M portion of salaries, straight time labor, and overtime for internal employees. An attrition factor of 4 percent is applied, which reduces labor costs to account for retirements, hiring delays, and other employee transfers. These amounts include costs for both NSPM employees and the appropriate allocation of Xcel Energy Services employees. For capital construction-focused positions, the vast majority of the labor costs are allocated to capital; however, some labor costs are charged to O&M like employee meetings, training, and administrative functions.

Q. WHAT CHANGES IN INTERNAL LABOR COSTS DO YOU ANTICIPATE FOR 2022 THROUGH 2024?

A. We are expecting an average annual increase of 3 percent in internal labor costs from 2022 through 2024.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND THE INCREASE IN INTERNAL LABOR COSTS FROM 2022 TO 2024?

A. The increase in internal labor costs from 2022 to 2024 budgets is primarily due to annual base pay increases for both bargaining and non-bargaining employees. These annual base pay increases and the historical trends for base pay increases are discussed more fully in the Direct Testimony of Ms. Lowenthal. In 2022, there are also increases in internal labor costs due to OT Security program costs.

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE INCREASES IN INTERNAL LABOR COSTS.

A. The Transmission business unit closely monitors our overall headcount numbers, ensuring that any increases in headcount above the budgeted levels are prudent and fully reviewed. In addition, we closely monitor the amount of time spent on capital activities on a monthly basis as part of the overall monthly reporting to manage the amount of internal labor being charged to O&M.

2. *Contract Labor and Consulting*

Q. WHAT COSTS ARE INCLUDED IN THE TRANSMISSION O&M BUDGET FOR CONTRACT LABOR AND CONSULTING?

A. This category represents our use of contract labor and consultants, which allows the Company to increase and decrease its staffing levels as workloads require rather than bringing on more full-time staff. Using contract labor also allows us the ability to retain the services of experts, as needed, for specific tasks or project efforts. We believe utilizing contractors and consultants in this way is an efficient and cost-effective way to complete required work while ensuring the cost for the resources is only incurred during time it is needed.

Q. WHAT CHANGES IN CONTRACT LABOR AND CONSULTING COSTS DO YOU ANTICIPATE FOR 2022 THROUGH 2024?

A. We are expecting contract labor and consulting costs to be 20 percent less than the average actual costs for 2018 to 2020 ($4.4 million vs. $3.5 million) and to remain constant at that lower level.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND THIS DECREASE IN CONTRACT LABOR AND CONSULTING COSTS?

A. The decrease in contract labor and consulting costs is driven by productivity improvement initiatives, which have been implemented by the business. These efforts have resulted in improved scheduling and field productivity, resulting in more efficient and effective ways for transmission crews to spend their time, thus reducing the need for contractor support and the outsourcing of certain O&M activities.

Q. WHAT STEPS HAS TRANSMISSION TAKEN TO MINIMIZE CONTRACT LABOR COSTS?

A. While utilizing contractors and consultants can be a cost-effective method of managing labor costs on projects with variable workloads, the Transmission business unit continues to take steps to minimize the cost of contract labor and consulting costs. This includes increasing the reliance on workload planning to ensure the staffing levels, including both internal and external resources, are at the minimum required levels. Furthermore, the Transmission business unit utilizes strategic sourcing and the competitively bid Master Service Agreement program to obtain qualified and cost-effective contract labor. The Master Service Agreement program creates supply agreements with several preferred vendors to obtain bulk discounts and better service.

3. Employee Expenses

Q. WHAT COSTS ARE INCLUDED IN THE O&M BUDGET FOR EMPLOYEE EXPENSES?

A. This category represents expenses incurred by employees when traveling to remote locations to perform field work or traveling to required trainings, personal communication device expenses, and necessary (non-capital) safety equipment. Travel expenses incurred include per diem, mileage, lodging, airfare, travel meals, and other travel-related expenditures.

Q. WHAT CHANGES IN EMPLOYEE EXPENSE COSTS DO YOU ANTICIPATE FOR 2022 THROUGH 2024?

A. We are expecting an average decrease of 19 percent in employee expenses for 2022 to 2024, as compared to the average of the 2018 to 2020 actual costs ($2.5 million vs. $2.0 million) and for costs to remain constant at that lower level. This is based on the assumption that technology utilized during the pandemic will continue to be utilized in 2022-2024 to decrease employee expenses.

4. Fees

Q. WHAT FEES ARE INCLUDED IN THE TRANSMISSION BUSINESS UNIT BUDGET?

A. This category consists of fees we are required to pay to the NERC and MRO for the operation of the transmission system. As a regulated utility, the Company is required to pay fees for each of those organization's operating costs. It also includes professional and utility association dues, as well as land and railroad permits and license fees, and other similar fees necessary for the operation of our business. As shown in Table 10, fees are budgeted to remain flat from 2022 through 2024.

5. Materials

Q. WHAT MATERIALS ARE INCLUDED IN THE TRANSMISSION BUSINESS UNIT BUDGET?

A. This category consists primarily of consumables, hardware, and refurbished materials used in substation maintenance and repair operations. Additionally, tools, small equipment, and supporting supplies are included.

Q. WHAT CHANGES IN MATERIALS COSTS DO YOU ANTICIPATE FOR 2022 TO 2024 AS COMPARED TO 2020 ACTUALS?

A. We are expecting an average decrease of 15 percent in material costs for 2022 to 2024, as compared to the average of the 2018 to 2020 actual material costs ($2.6 million vs. $2.3 million), and for costs to remain constant at that level.

Q. WHAT ARE THE MAJOR DRIVERS BEHIND THIS DECREASE IN MATERIAL COSTS?

A. This decrease in material costs is driven by policy reviews conducted by the Company that resulted in, among other things, changes in how the Company determined whether to repair versus replace certain assets. Specifically, this resulted in Transmission replacing more assets as opposed to repairing them which led to a reduction in O&M expenditures for materials. In addition, the Transmission business unit continues to take advantage of the Master Service Agreement program, utilizing negotiated supply agreements with several preferred vendors to obtain bulk discounts and better service. We are also continuing to look for opportunities to optimize the sourcing for materials through efficiencies gained within the supply chain organization as well as an increased focused on improving adherence to capital policy guidelines.

6. Miscellaneous

Q. WHAT COSTS ARE INCLUDED IN THE MISCELLANEOUS CATEGORY?

A. The miscellaneous category is primarily fleet costs. This category consists of costs for the internal fleet assets as directed to O&M accounts on an hourly basis by Transmission operations. This is an aggregate cost of all fleet equipment charged to Transmission O&M, including cars, trucks, construction equipment, and trailers. In addition to fleet costs, the miscellaneous budget for

2022 to 2024 includes anticipated reductions in O&M as a result of productivity enhancements expected to be implemented by the Company.

Q. WHAT CHANGES IN MISCELLANEOUS COSTS DO YOU ANTICIPATE FOR 2022 TO 2024 AS COMPARED TO 2020 ACTUALS?

A. We are expecting an average decrease of 46 percent in miscellaneous costs for 2022 to 2024, as compared to the 2018 to 2020 average ($2.6 million vs. $1.4 million), and for costs to remain constant at that lower level. Efforts to reduce per unit expense for transportation costs have resulted in decreased total fleet expenditures. Additionally, improvements in vehicle utilization tracking have resulted in fleet time and dollars being more accurately assigned to capital versus O&M projects, resulting in reduced O&M spending. Lastly, certain anticipated O&M reductions resulting from efficiency efforts initiated by the Company are captured in the miscellaneous cost category for the 2022 to 2024 budget.

V. THIRD-PARTY TRANSMISSION EXPENSES AND WHOLESALE TRANSMISSION REVENUES

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

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I discuss the Company's third-party transmission revenues and expenses and the impact that pending FERC proceedings have on those revenues and expenses.

Q. GENERALLY SPEAKING, WHAT ARE THIRD-PARTY TRANSMISSION EXPENSES?

A. While NSP Transmission System loads and transmission facilities are primarily located within the NSP pricing zone, the NSP Companies serve loads in four other MISO pricing zones and a small load outside MISO. The NSP Companies also collect revenue for transmission facilities located in the GRE pricing zone, and several other utilities collect revenue for transmission facilities located in the NSP pricing zone.

As a result, the NSP Companies incur third-party transmission expenses to serve their native load customers, either in other zones or under Joint Pricing Zone (JPZ) arrangements developed to compensate other utilities for their facilities in the NSP pricing zone consistent with the MISO Transmission Owners Agreement. The NSP Companies also receive revenues for transmission and ancillary services provided to other utilities with load in pricing zones where NSP owns transmission assets or as otherwise provided under the MISO Tariff.

Q. WHAT IS THE RELATIONSHIP OF THIRD-PARTY TRANSMISSION EXPENSES AND WHOLESALE TRANSMISSION REVENUES TO THE COMPANY'S COST OF SERVICE?

A. Third-party transmission expenses and wholesale transmission revenues can either serve as a credit or debit to the Transmission business unit's O&M costs.

Q. PLEASE DESCRIBE THE HISTORICAL DEVELOPMENT OF THE 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 Twin Cities, several major cities including St. Cloud, Mankato, and Winona, and about 400 other communities in Minnesota, while other utilities serve areas between the Company's territories. This is because electric utilities in Minnesota and the upper Midwest (investor-owned, cooperatives, and 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 THE HISTORY OF COOPERATION AFFECT THE COSTS TO MINNESOTA CUSTOMERS?

A. As designed and implemented, the jointly developed multi-owner transmission grid in Minnesota has resulted in less duplication of facilities and increased system efficiency. This has resulted in lower costs to customers throughout Minnesota.

Today, access to that multi-owner transmission grid is available under the MISO Tariff. Essentially, the Company receives revenue from other entities that use our transmission system and incurs an expense for using the transmission systems of other entities.

B. Third-Party Transmission Expenses and Revenues

Q. PLEASE EXPLAIN HOW THE WHOLESALE REVENUES AND THIRD-PARTY EXPENSES ARE RECOVERED.

A. The MISO Tariff recovers the costs of transmission facilities through rates established and billed by "pricing zones," which 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. HOW DOES THE BILLING WORK?

A. The Company is party to JPZ agreements for both the NSP pricing zone and the GRE pricing zone. Under these agreements, 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. Since the NSP Companies are both transmission owners and load serving entities in both pricing zones, the

NSP Transmission System (1) receives revenues for its facilities in the NSP and GRE pricing zone and (2) incurs expenses for its loads in the NSP and GRE pricing zones.

Furthermore, as a MISO transmission owner, the NSP Companies collect third-party wholesale transmission service revenues for others' use of the NSP Transmission System under both the MISO Tariff and other wholesale transmission agreements. The NSP Transmission System also incurs transmission and/or ancillary expenses for its loads in other MISO pricing zones.

Q. PLEASE DESCRIBE THE TRANSMISSION THIRD-PARTY EXPENSES AND WHOLESALE REVENUES FOR 2022 TO 2024.

A. The NSP Transmission 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 NSP Transmission System loads, including NSPM retail native loads in Minnesota, and thus the costs should be included in rates. However, those costs are offset by various transmission service revenues, thereby reducing total costs to NSPM customers in Minnesota. Table 16 summarizes the 2022 to 2024 budgets for MISO third-party transmission revenues and expenses and administrative charges for the total NSP Transmission System, compared to 2020 actual and 2021 forecast amounts.

Table 16

NSP Transmission System

Third Party Transmission Expenses and Revenues

($000)

Description					
Third Party Transmission Expenses	**2020 Actual**	**2021 Forecast**	**2022 Budget**	**2023 Budget**	**2024 Budget**
JPZ Payments (NSP and GRE Zones)	47,798	60,894	59,738	60,079	61,247
MISO Network Service, Point to Point, and Ancillary Services	20,857	22,900	22,021	22,349	22,593
MISO Admin Charges (Sch 10)	11,141	12,639	13,117	13,464	13,797
Other (Transmission Facilities/Other Native Load Deliveries, etc.)	209	274	514	518	520
TOTAL Third-Party Expenses	80,004	96,707	95,390	96,409	98,158
Wholesale Transmission Revenues	**2020 Actual**	**2021 Forecast**	**2022 Budget**	**2023 Budget**	**2024 Budget**
JPZ Revenues (NSP and GRE Zones)	48,635	55,467	58,624	60,198	61,917
MISO Network Service	31,983	30,145	30,974	31,903	32,859
MISO Point to Point	6,706	7,807	6,152	6,158	6,163
GFAs	426	2,101	437	438	440
Self-Funded Network Upgrades	201	1,666	5,214	5,453	5,660
Transmission Owner Interconnection Facilities - O&M	0	0	501	501	501
Other (Ancillary Services/LBA Services, etc.)	1,818	1,857	1,921	1,959	1,998
TOTAL Third-Party Revenues	89,770	99,042	103,822	106,610	109,538
Net Expense (Revenue)	(9,766)	(2,334)	(8,432)	(10,200)	(11,380)

**2021 Forecast is based on 2021 Actuals Jan-Jul with 06.08.21 forecast for Aug and 9.07.21 forecast for Sep - Dec

***2022-2024 budget is based on the MN approved state ROE of 9.06%

Since NSPM and NSPW operate the NSP Transmission System as an integrated system, the table above reflects NSP Transmission System revenues and expenses. The third-party transmission expenses and revenues are described in more detail later in my testimony and in Exhibit___(IRB-1), Schedules 5 and 6. The 2022, 2023, and 2024 budget shows net revenue which serves to decrease to the Company's overall retail cost of service.

Q. DO THE TRANSMISSION EXPENSES YOU DESCRIBE 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 an MVP. The Company includes MISO Schedule 26 and 26A charges, as well as an offset for Schedule 26 and 26A revenues, in the TCR Rider.

Q. PLEASE DESCRIBE THE 2022, 2023, AND 2024 NSP TRANSMISSION SYSTEM THIRD-PARTY TRANSMISSION EXPENSES.

A. There are several types of third-party costs, which are summarized in Exhibit ___(IRB-1), Schedule 5. These are NSP Transmission System transmission costs necessary to serve NSP Transmission System loads, including NSP retail native loads in Minnesota, pursuant to rate schedules accepted for filing by FERC. My testimony provides the NSP Transmission System costs; Mr. Halama's cost of service reflects the portion allocated to the Minnesota jurisdiction.

- *JPZ Costs* – As I previously discussed, the NSP Transmission System incurs costs for serving its native loads within the NSP Joint Pricing Zone and in the GRE Joint Pricing Zone. The Company, GRE, Southern Minnesota Municipal Power Agency, Central Minnesota Municipal Power Agency, Northwestern Wisconsin Electric Company, Minnesota Municipal Power Agency, Missouri River Energy Services, East River Electric Power Cooperative and Rochester Public Utilities (collectively the "NSP Zone Transmission Owners") each own transmission facilities and serve loads in the NSP pricing zone. The 2022 to 2024 expense is for our use of the NSP Transmission Owners transmission facilities to serve the NSP Transmission System loads in the NSP pricing zone. The revenue reflects use of the NSP Transmission System facilities by other utilities to serve their respective loads in the NSP zone. The NSP Transmission System 2022, 2023, and 2024 net payment under the NSP-JPZ arrangement is forecast to be \$2.5 million, \$1.3 million, and \$0.7 million, respectively, based on the JPZ expense and JPZ revenue summarized in Table 17 below.

Table 17

Joint Pricing Zone – NSP Zone

(Dollars in Millions)

	Revenue	Expense	Net Payment
2022	$53.2	$55.7	$2.5
2023	$54.6	$55.9	$1.3
2024	$56.2	$56.9	$0.7

Similarly, the NSP Transmission System has both native load and transmission facilities located in the GRE pricing zone, which is also a multi-utility zone. The Company pays GRE a net payment consisting of expense and revenue components: the expense of using other parties' facilities to serve the Company's native load, and the revenue paid by other parties for their use of NSP's facilities in the GRE zone. The NSP Transmission System 2022, 2023, and 2024 net receipt for the GRE JPZ is forecast to be $1.4 million annually, based on the JPZ expense and JPZ revenue summarized in Table 18 below.

Table 18
Joint Pricing Zone - GRE Zone
(Dollars in Millions)

	Revenue	Expense	Net Receipt
2022	$5.4	$4.0	$1.4
2023	$5.6	$4.2	$1.4
2024	$5.7	$4.3	$1.4

Thus, the combined 2022 impact of both the NSP JPZ and GRE JPZ is a net payment of $1.1 million. The combined 2023 and 2024 impact of both the NSP JPZ and GRE JPZ is a net receipt of $0.1 million and $0.7 million on total expense and revenue summarized in Table 19 below and in Exhibit ___(IRB-1), Schedule 7.

Table 19

Joint Pricing Zone - NSP and GRE Zones

(Dollars in Millions)

	Revenue	Expense	Net (Receipt) Payment
2022	$58.6	$59.7	$1.1
2023	$60.2	$60.1	($0.1)
2024	$61.9	$61.2	($0.7)

- *Network Integration Transmission Service (NITS), Point to Point, and Ancillary Service Costs* – All NSP Transmission System native loads located within MISO are required to pay either a JPZ charge, as described above, or to purchase NITS under Schedule 9 of the MISO Tariff. Accordingly, the NSP Companies incur such charges with respect to their native loads in the Dairyland Power Cooperative, and ITC Midwest pricing zones. The NSP Companies' load in the Otter Tail Power pricing zone is treated as being in the NSP pricing zone for JPZ/NITS purposes. In addition to the base transmission (JPZ/NITS) charge, each load is also ascribed charges, as applicable, under the MISO Tariff for ancillary services, such as Schedule 1 – Scheduling, System Control and Dispatch Services, Schedule 2 – Reactive Supply and Voltage Control From Generation or Other Sources Service, and Schedule 33 – Blackstart Service. Finally, the Company serves a small native load in Berthold, North Dakota, that is connected to the Southwest Power Pool (SPP) system outside the MISO region. Under the MISO Tariff, the Company is required to purchase point-to-point (PTP) transmission service and associated ancillary services to export power supply resources from the MISO region. The

NSP Transmission System 2022, 2023, and 2024 payments to MISO for these services are forecasted to be $22.0 million, $22.3 million, and $22.6 million, respectively.

- *MISO Administrative Charges* – MISO charges its transmission service customers, such as the Company, its Schedule 10 administrative charges to recover the costs of administering its Tariff and providing other transmission functions. The 2022, 2023, and 2024 charges of $13.1 million, $13.5 million, and $13.8 million, respectively, are based on MISO's forecast of its Schedule 10 rates.
- *Other Transmission Expense/Facility Charges.* The NSP Companies incur these costs to secure delivery rights for the integration of NSP Transmission System loads. This cost consists of payments to Dairyland Power Cooperative, Minnkota Power Cooperative, McLeod Cooperative Power Association, Verendrye Electric Cooperative, Southwest Power Pool, and Stearns Electric Association for use of their respective facilities to enable the Company to serve certain native loads. The NSP Transmission System 2022, 2023, and 2024 payments to these entities are forecast to be $514,000; $518,000; and $520,000, respectively.

Q. WHAT ARE THE 2022, 2023, AND 2024 WHOLESALE TRANSMISSION REVENUES?

A. As shown in Table 15, the total NSP Transmission System 2022 test year wholesale revenues are estimated to be $103.8 million. The NSP Transmission System wholesale revenues for the 2023 and 2024 plan years are estimated to be $106.6 million and $109.5 million, respectively. Exhibit___(IRB-1), Schedule 6 provides more detailed information on the various transmission service revenues by type of service for 2020, 2022, 2023, and 2024. The revenues from these wholesale services are reflected as revenue credits in the cost of service supported by Mr. Halama, thereby offsetting some of the third-party transmission expenses and reducing total costs to our Minnesota customers.

Q. HOW ARE THE WHOLESALE TRANSMISSION REVENUES KEPT ACCURATE AND CURRENT?

A. The NSP Companies update their MISO Attachment O ATRR every year. This update is required by the MISO Tariff and coordinated with MISO Tariff Administration staff to reflect current year projected costs and the true-up of prior period costs and loads.

C. Pending FERC ROE Proceedings

Q. PLEASE EXPLAIN THE BACKGROUND OF THE PENDING FERC ROE PROCEEDINGS IN FERC DOCKET NOS. EL14-12 AND EL15-45.

A. On November 12, 2013, a group of industrial customers in the MISO region filed a complaint (FERC Docket No. EL14-12, or the "First Complaint") asking FERC to reduce the base rate of ROE used in the transmission formula rates of jurisdictional MISO transmission owners (MISO TOs), including the NSP Companies, from 12.38 percent to 9.15 percent. On September 28, 2016, FERC issued Opinion 551, granting a 10.32 percent base rate ROE, effective November 12, 2013 to February 10, 2015 and prospectively from the date of the Order. Per Opinion 551, refunds were issued during the first half of 2017; however, multiple parties requested rehearing of Opinion 551, as discussed further below.

In February 2015, due to the impending expiration of the 15-month statutory limit on refund periods for complaints under section 206 of the Federal Power Act, a second Complaint (FERC Docket No. EL15-45, the "Second

Complaint", or, together with the First Complaint, the "MISO ROE Complaints") was filed proposing to reduce the base ROE from 12.38 percent to 8.67 percent. The Second Complaint created a period of potential refunds from February 12, 2015 to May 11, 2016. In June 2016, based on the Opinion 531 methodology, an ALJ recommended a base ROE of 9.70 percent ("Second Complaint Initial Decision").[11] However, multiple parties filed exceptions to the Second Complaint Initial Decision, and the complaint continues to be subject to ongoing litigation, as discussed further below.

On April 14, 2017, the United States Court of Appeals, D.C. Circuit (D.C. Circuit Court) vacated and remanded Opinion 531, finding that FERC had not properly established that the existing ROE was unjust and unreasonable and also failed to adequately support the newly approved base ROE.[12] As Opinion 551 and the Second Complaint Initial Decision both cited Opinion 531 as the basis for the respective decisions, Opinion 531's vacatur also invalidated those decisions.

On November 21, 2019, FERC issued Opinion 569, an order on rehearing of Opinion 551 and FERC's initial order on the Second Complaint. Opinion 569 adopted a new ROE methodology and set a new base ROE of 9.88 percent, effective for the 15-month refund period from November 12, 2013, to February 11, 2015, and prospectively from September 28, 2016. Opinion 569 also dismissed the Second Complaint on the basis that the "existing rate" to be evaluated in that complaint was the 9.88 percent base ROE ordered in the First Complaint, which continued to be just and reasonable through the Second

[11] 155 FERC ¶ 63,030 (2016).
[12] *Emera Maine*, 854 F.3d at 22-23.

Complaint period. This dismissal drew a strongly worded dissent from Commissioner Richard Glick, who, like the Complainant-Aligned Parties (CAPs), contended FERC should evaluate the Second Complaint not against the outcome of the First Complaint, but against the 12.38 percent base ROE inherent in rates paid by customers during the Second Complaint's refund period. Various parties requested rehearing of Opinion 569 on multiple grounds, including which models should be used to evaluate and set a new base ROE, how the models should be applied, FERC's use of judgment, and the dismissal of the Second Complaint.

On May 21, 2020, FERC issued Opinion 569-A, which granted rehearing in part of Opinion 569, adopting a new ROE methodology which includes the risk premium model in addition to the discounted cash flow (DCF) and capital asset pricing model (CAPM), and established yet another new base ROE of 10.02 percent, effective for the First Complaint refund period (November 12, 2013 to February 11, 2015), and prospectively beginning September 28, 2016. The MISO TOs did not request rehearing but did appeal the decision to the D.C. Circuit Court, as discussed below.

On June 30, 2020, the D.C. Circuit Court issued an opinion in an unrelated case, *Allegheny Defense Project v. FERC,* finding FERC's practice of issuing "tolling orders," which previously had the effect of allowing FERC unlimited time to act on requests for rehearing, to be unlawful, and requiring FERC to act on requests for rehearing within 30 days.[13] On July 22, 2020, in response to the *Allegheny* decision, FERC issued an order denying the requests for rehearing as

[13] *Allegheny Defense Project v. Federal Energy Regulatory Commission*, 964 F.3d 1, 18-19 (D.C. Cir. 2020).

a matter of law, though FERC also indicated its intention to set aside its previous decision and issue a new order on rehearing at a future date.

Between June 1, 2020 and July 20, 2020, seven different groups, including the MISO TOs, filed petitions for review of Opinions 551, 569, and 569-A with the D.C. Circuit Court. On August 5, 2020, FERC filed a motion to hold the appeals in abeyance pending FERC's intended action on rehearing.

On November 19, 2020 the FERC issued Opinion 569-B, which reaffirmed its conclusions reached in Opinion 569-A, denying requests for rehearing on most items while making minor technical corrections on others without changing the conclusions.

On March 9, 2021, the MISO TOs filed an initial joint brief with the D.C. Circuit citing FERC exceeded its statutory limits by (1) ordering retroactive refunds for 2016-2020, and (2) setting the Second Complaint for hearing rather than dismissing and thus served to only double the length of the First Complaint. Complainants and other intervenors also filed briefs, largely focused on refunds for the second complaint and technical challenges to FERC's derivation of the new ROE. Also, in March 2021, complainant-aligned petitioners filed reply briefs which closely aligned with Commissioner Glick's dissent of Opinion 569-A and 569-B.

In June 2021, the FERC filed its respondent brief, defending the decisions reached in Opinion 569-A and 569-B. Also, in June 2021, parties filed various reply briefs with the final briefs filed in August 2021. The oral arguments have been scheduled for November 18, 2021 but it is uncertain as to when the D.C. Circuit will make a decision or what the ultimate outcome will be.

Q. WHAT IS THE NSP COMPANIES' MOST RECENT FERC-APPROVED ROE AT THIS TIME?

A. The most recent FERC order establishing a new base ROE for the NSP Companies is FERC Opinion 569-A, which set the base ROE at 10.02 percent. Although that Order remains subject to change from ongoing litigation, billed rates are currently based on that order and use a total ROE of 10.52 percent (10.02 percent base ROE, plus a 50 basis point incentive adder for RTO participation).

Q. DOES THE COMPANY HAVE CERTAINTY AT THIS POINT AS TO THE FINAL MISO ROE THAT WILL BE ADOPTED BY FERC?

A. Not at this time. As evidenced by the multiple appeals at the D.C. Circuit Court there is still quite a bit of uncertainty as to the final ROE that will be adopted.

Q. WHAT HAS BEEN THE IMPACT OF THE MISO ROE COMPLAINTS ON NSPM'S FINANCIAL RESULTS FOR ITS MINNESOTA ELECTRIC JURISDICTION?

A. In previous Minnesota rate cases, the transmission revenue credit, which represents the pass-through to retail customers of revenues received for providing transmission service to other utilities, resulting in a reduction to the cost of service, has been calculated using the previously effective MISO ROE of 12.38 percent. The Company has issued initial refunds for Opinion 569B for the time period from November 2013 through February 2015, September 2016 through December 2016, 2019, and 2020 as of June 2021. As a result, the transmission revenues actually earned have fallen short of the level credited to

Minnesota retail customers, causing financial loss to the Company that I discuss in more detail below.

Q. IS THERE A TRUE-UP MECHANISM TO PROTECT THE COMPANY AND RETAIL CUSTOMERS FROM THE FINANCIAL IMPACTS RESULTING FROM CHANGES TO THE MISO ROE DUE TO THE MULTIPLE PENDING FERC PROCEEDINGS?

A. No, at least not for transmission revenues credited to customers through base rates. Certain types of transmission revenue are credited to customers through the TCR Rider, which includes a true-up to ensure customers are credited with the actual amount, no more and no less, of the revenues received. However, for items included in base rates, there has been no true-up mechanism in place.

Q. CAN YOU QUANTIFY THE AMOUNT OF LOSSES EXPERIENCED BY THE COMPANY AS A RESULT OF THE DIFFERENCE BETWEEN THE ULTIMATE FERC ROE AND THE ROE USED TO CALCULATE THE MINNESOTA REVENUE CREDIT?

A. As I discussed previously, the ultimate outcome of the MISO ROE Complaints, including refunds for the time period since November 2013, is uncertain at this time. However, Table 20 below estimates the difference, on a Minnesota jurisdictional basis, between the level of the Company's transmission revenues included as a revenue credit in its previous rate cases, based on the 12.38 percent previously effective base ROE and what that revenue credit would have been had the 10.02 percent base ROE from Opinion 569-B been known at the time those cases were filed.[14]

[14] An incentive adder of 50 basis points for RTO participation is applicable to periods on or after January 6, 2016; thus, for those periods, the 12.38 percent previous ROE is compared against a new ROE of 10.52 percent.

Table 20

Estimated Impact of ROE on Transmission Revenues

(State of MN Electric Jurisdiction)

Year	**12.38% vs. 10.02% base ROE *($000s)***
2013	$323
2014	$5,210
2015	$4,547
2016	$2,998
2017	$4,738
2018	$4,064
2019	$4,266
2020	$4,452
2021	$4,875
Total	**$35,473**

Thus, the Minnesota jurisdiction has received excess revenue credits of approximately $35.5 million from 2013 to 2021.

Q. WHAT DOES THE COMPANY RECOMMEND WITH RESPECT TO THE TRANSMISSION REVENUE CREDIT IN THIS CASE?

A. As discussed by Mr. Halama, the Company believes a determination at FERC on this matter should not impact the retail jurisdiction, and the cost of capital should be treated consistently across our rate base. Therefore, the transmission revenue credit has been calculated using the Company's most recently approved TCR Rider ROE of 9.06 percent approved by the Commission in the Company's latest TCR Rider proceeding.[15]

[15] *In the Matter of the Petition of Northern States Power Company for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2017 and 2018, and Revised Adjustment Factor*, Docket No. E002/M-17-797, ORDER

Q. WHAT IS THE IMPACT OF A LOWER FERC AUTHORIZED ROE?

A. For the 2022 test year, a 10 basis point (0.1 percentage point) reduction in the FERC authorized ROE is estimated to result in a reduction in wholesale transmission revenues, net of third-party transmission expenses, of approximately $0.4 million. This amount excludes revenues and expenses under MISO Schedules 26 and 26A, which are excluded from base rates and instead included in the TCR Rider.

VI. TRANSMISSION SYSTEM LINE LOSS ANALYSIS

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In its June 12, 2017 Order in our 2015 electric rate case, the Commission determined that the consideration of line losses—the amount of energy that is lost through the process of transmission and distribution—may further enhance the accuracy of the Class Cost of Service Study.[16] As a result, the Commission directed the Company in its next rate case to report on methods to conduct loss studies to measure line losses. The two general categories of losses on the Xcel Energy system are transmission losses and distribution losses. I will discuss the methods for measuring transmission losses, while Company witness Ms. Kelly A. Bloch discusses the methods for measuring distribution losses in her Direct Testimony.

AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS (Sept. 27, 2019).

[16] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-15-826, FINDINGS OF FACT, CONCLUSIONS, AND ORDER, at 49 (June 12, 2017).

Q. WHAT ARE ELECTRIC LOSSES?

A. The Edison Electric Institute (EEI) defines electric losses as the general term applied to energy (measured in kilowatt-hours) and power (demand losses measured in kilowatts) lost in the operation of an electric system. Losses occur when energy is converted into waste heat in conductors and apparatus. Demand loss is power loss and is the normal quantity that is conveniently calculated because of the availability of equations and data. Demand loss is coincident when occurring at the time of system peak, and non-coincident when occurring at the time of equipment or subsystem peak. Class peak demand occurs at the time when that class's total peak is reached.

Q. HOW DOES THE COMPANY CALCULATE LOSSES ON THE TRANSMISSION SYSTEM?

A. The Company uses NSP hourly State Estimator data to calculate both the demand and energy losses on the NSP Transmission System.

Q. WHAT IS THE STATE ESTIMATOR?

A. The State Estimator is basically an on-line power flow program that creates a complete complex voltage solution for the network model. The State Estimator solution is based on real-time measurements, scheduled load and generation, and dispatcher/operator entries. The State Estimator is performed several times per hour and provides a continuous snapshot of the transmission network.

Q. HOW DOES THE STATE ESTIMATOR OBTAIN THE REAL-TIME MEASUREMENTS FROM THE TRANSMISSION SYSTEM?

A. The State Estimator uses real-time data from the Company's EMS. The EMS is an integrated set of computer hardware, software, and computer programs which aid Company transmission system operators in viewing, monitoring, and operating the transmission system. The EMS receives real-time measurements from the field through telemetry. These real-time measurements are imperfect but redundant. This redundancy permits the State Estimator to determine an estimate for the voltage magnitude and angles for the observable portion of the network model which best matches the information given by the unfiltered measurements.

Q. ARE REAL-TIME MEASUREMENTS AVAILABLE FOR ALL OF PORTIONS OF THE TRANSMISSION SYSTEM?

A. No. Portions of the network are not observable with real-time measurements. For those portions of the system, the State Estimator uses data from key nodal points on the system from which we have telemetry data to determine the overall system status. That system status, which includes load and generation values along with voltages and amperage, also reflects the overall losses on the system.

Q. HOW DOES THE STATE ESTIMATOR UTILIZE THIS NETWORK DATA?

A. The State Estimator utilizes all of the collected data to create a real-time snapshot of the transmission network. This solved real-time network snapshot can be used for several applications including calculating transmission system losses.

Q. HOW CAN THIS REAL-TIME NETWORK BE USED TO CALCULATE TRANSMISSION SYSTEM LOSSES?

A. The State Estimator has the ability to provide over 8,000 states of data for calculating losses. The demand losses are the losses that occur on the NSP

Transmission System during the monthly peak hourly load. Energy losses will be the summation of all hourly losses in each month.

To calculate the required percentages, these losses will then be divided by NSP's local balancing authority (LBA) load. In the case of demand losses, the load will be the peak hour load while the energy loss will be the summation of MWh loads in the given month.

Not all the loads in NSP's LBA are NSP's native load. Loads from GRE and Dairyland Power Cooperative are within NSP's LBA. GRE is an electric cooperative based in Minnesota while Dairyland Power Cooperative is an electric cooperative based in Wisconsin. These loads also create losses on the transmission system and need to be added to NSP's load to obtain the correct loss percentages.

Q. WHAT ARE THE LIMITATIONS OF USING THE STATE ESTIMATOR CALCULATIONS OF TRANSMISSION SYSTEM LOSSES?

A. At the end of the day, any transmission system losses calculated by the State Estimator is an estimate based on collected data and may not necessarily reflect actual line losses at any given point in time. This is because the loss calculations created by the State Estimator rely on estimates for the portions of the system where we do not have real-time telemetry and are averaged into hourly time intervals.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Transmission organization constructs and maintains the transmission components for the NSP Transmission System that are necessary to enable the safe, reliable, and efficient delivery of energy from generating resources to customers. We anticipate completing $412.9 million of capital additions in 2022, $418.4 million in 2023, and $361.4 million in 2024. These capital projects are needed to maintain the health of transmission facilities, meet reliability requirements, add capacity to support increasing amounts of new generation, interconnect new generators, and enable communication between our facilities.

We have budgeted $31.6 million for Transmission O&M in 2022, $32.2 million in 2023, and $32.8 million in 2024. The three-year average for these years ($32.2 million) is below the most recent three-year historical average (2018 to 2020) of $35.7 million.

These capital and O&M budgets are a reasonable representation of the work that Transmission will complete during the term of this MYRP and I recommend that the Commission approve Transmission's capital and O&M budget as presented in this rate case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications
Ian R. Benson

Current Responsibilities

My responsibilities include: supervising engineers in planning the electric transmission systems for the four Xcel Energy Inc. operating companies, NSPM, Northern States Power Company, a Wisconsin corporation (together the NSP Companies), Public Service Company of Colorado (PSCo), and Southwestern Public Service Company (SPS); overseeing the development of local and regional transmission system plans, including coordinated joint planning with the Midcontinent Independent Transmission System Operator, Inc. (MISO), and other utilities to ensure reliable transmission service; recommending the construction of such plans to Xcel Energy Inc. management and MISO; participating in and supporting MISO sponsored transmission service studies, generation interconnection studies, long range regional plan development, load service planning and other transmission planning activities required by MISO to perform its obligations under the MISO Tariff and the MISO Transmission Owner's Agreement; and providing technical support for regulatory aspects of transmission system planning activities and contract development for the NSP Companies, PSCo, and SPS.

Education:

Bachelor of Geological Engineering - 1984
University of Minnesota

Bachelor of Science, Mathematics – 1991
University of Minnesota

Master of Business Administration – 2010
University of St Thomas

Previous Employment (1991 to 2010):

Senior Engineer - Northern States Power Company (1991 – 1994)
Lead Sales Representative - Northern States Power Company (1994 – 1998)
Mid-Term Marketing Representative - Northern States Power Company (1998 – 1999)
Manager, Mid-Term Markets - Northern States Power Company (1999 – 2000)
Director, Origination - Xcel Energy Services Inc. (XES) (2000 – 2004)
Director, Transmission Access - XES (2004 – 2009)
Director, Transmission Investment Development - XES (2009 – 2010)
Director, Transmission Business Relations and Asset Management - XES (2010 – 2013)
Director, Transmission Planning and Business Relations - XES (2013 – 2016)
Area Vice President, Transmission Strategy and Planning – XES (2016 – present)

U.S. Navy

Active Duty: 1984 to 1989
Naval Reserve: 1989 to 2006

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2022		2023		2024		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	Date
NSPM Additions										
Asset Renewal	NSPM Major Line Rebuild	A.0000351.004	NSPM Major Line Rebuild,Line	0	0	52,129	38,070	56,238	41,070	1/1/2027
Asset Renewal	NSPM Major Line Rebuild	A.0000351.058	0761 LAK ZUM Rebuild	8,468	6,185	0	0	0	0	12/15/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.037	NSM0703 FRM PKN Rebuild	7,711	5,631	0	0	0	0	12/15/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.055	0723 Atwater - Cosmos (GRE)	0	0	0	0	7,380	5,390	12/13/2024
Asset Renewal	NSPM Major Line Rebuild	A.0000351.026	NSM0730 - West Sioux Falls - Line 729	304	222	6,500	4,747	0	0	12/15/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.030	NSM0752 Belgrade - Paynesville Rebuild	6,796	4,963	0	0	0	0	5/16/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.054	0723 Bird Island - Lake Lillian	0	0	5,609	4,096	0	0	2/28/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.043	NSM0790 Dassel-Cokato Rebuild	5,460	3,987	0	0	0	0	12/15/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.065	NSPM 0795 Wobegon Trail - Albany	0	0	4,699	3,432	66	48	12/15/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.044	NSM0790 Cokato - Howard Lake Rebuild	0	0	0	0	4,654	3,399	12/15/2024
Asset Renewal	NSPM Major Line Rebuild	A.0000351.048	NSM0790 Victor - Winsted Rebuild	0	0	4,538	3,314	0	0	6/15/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.049	NSM0790 Victor - 4N185 Rebuild	0	0	4,231	3,090	0	0	12/15/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.033	NSPM 0795 Avon - Albany	4,206	3,072	0	0	0	0	2/15/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.053	0723 Cosmos (GRE) - Lake Lillian	0	0	3,906	2,853	0	0	7/28/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.062	NSPM 0795 St. John's - Watab River	3,278	2,394	0	0	0	0	6/15/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.036	NSM0794 BLD DGC Rebuild	2,779	2,029	0	0	0	0	6/15/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.040	NSM0752 Belgrade - Paynesville PH2	2,683	1,959	0	0	0	0	12/15/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.039	NSM5401 MLK WAK Rebuild	2,425	1,771	0	0	0	0	5/15/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.064	NSPM 0795 Avon - Brockway Tap	0	0	1,837	1,342	0	0	1/15/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.035	NSM0779 - Canisota Juntion - Salem,Line	1,791	1,308	0	0	0	0	2/16/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.050	NSM0893 BCK RRK REBLD STRS 14 TO 20	0	0	1,606	1,173	0	0	12/5/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.060	NSPM 0795 St. Joseph - Westwood Tap	0	0	1,287	940	0	0	6/15/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.051	NSM0892 BCK RRK REBLD STRS 14 TO 20	0	0	1,056	771	0	0	12/5/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.038	NSM0703 FRM NOF Rebuild	884	645	0	0	0	0	8/15/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.061	NSPM 0795 Watab River - St. Joseph	0	0	737	538	0	0	6/15/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.063	NSPM 0795 Brockway Tap - St. John's	0	0	555	405	0	0	1/15/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.059	NSPM 0795 Westwood Tap - West St. Cloud	0	0	550	402	0	0	6/15/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.031	NSPM0729 CEN LCO 69kV Rebuild	510	372	0	0	0	0	12/15/2021
Asset Renewal	NSPM Major Line Rebuild	A.0000351.066	NSPM 0795 Riverview - Wobegon Trail	0	0	432	316	8	6	12/15/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.057	NSM0779 STR 231 - Salem Rebuild	0	0	267	195	0	0	12/15/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.068	0726 Pipestone-Rock Ck-Wdstk rebuild	0	0	77	56	0	0	5/15/2023
Asset Renewal	NSPM Major Line Rebuild	A.0000351.067	NSM0754 Becker - Linn Street Rebuild	36	26	0	0	0	0	12/15/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.072	0741 Litchfield city tap-Atwater	23	17	0	0	0	0	12/15/2022
Asset Renewal	NSPM Major Line Rebuild	A.0000351.073	0741 Big Swan - Litchfield city tap	17	13	0	0	0	0	5/15/2022
Asset Renewal	S&E - NSP Line	A.0000177.043	NSPM S&E 69kV, Line	7,209	5,265	8,210	5,996	7,209	5,265	12/31/2026
Asset Renewal	S&E - NSP Line	A.0000177.056	NSPM Priority Defects 69kV Line	8,011	5,850	6,007	4,387	6,007	4,387	12/30/2026
Asset Renewal	S&E - NSP Line	A.0000177.055	SD S&E B 69kV, Line	100	73	100	73	100	73	11/1/2026
Asset Renewal	S&E - NSP Line	A.0000177.050	ND S&E B 69kV, Line	100	73	100	73	100	73	12/31/2026
Asset Renewal	ELR - Breakers - NSPM	A.0000394.009	NSPM ELR Breakers	4,003	2,923	14,724	10,753	9,826	7,176	10/31/2026
Asset Renewal	ELR - Breakers - NSPM	A.0000394.031	Arlington-Replace Bkrs 4S191,4S192,4S199	0	0	2,451	1,790	0	0	3/31/2023
Asset Renewal	ELR - Breakers - NSPM	A.0000394.026	Fifth St-Replace Bkrs 5M760,5M765,5M770	1,131	826	0	0	0	0	2/28/2022
Asset Renewal	ELR - Breakers - NSPM	A.0000394.027	Hugo-Replace Bkrs 5P196 & 5P197	888	648	0	0	0	0	12/15/2022
Asset Renewal	ELR - Breakers - NSPM	A.0000394.029	Minnesota Valley-Replace 69 kV & 115 kV Bkrs	0	0	881	644	0	0	12/15/2023
Asset Renewal	ELR - Breakers - NSPM	A.0000394.028	Inver Grove-Replace 4P8,4P9	877	641	0	0	0	0	12/15/2022
Asset Renewal	ELR - Breakers - NSPM	A.0000394.030	Prairie-Replace Bkrs 4G8 & 4G9	0	0	631	461	0	0	12/15/2023
Asset Renewal	ELR - Breakers - NSPM	A.0000394.045	St Cloud - Replace Gas Bkr - TR1 34.5	488	356	0	0	0	0	12/15/2022
Asset Renewal	ELR - Breakers - NSPM	A.0000394.044	BLUE LAKE - OIL BREAKER - TR2 13.8	488	356	0	0	0	0	12/15/2022
Asset Renewal	ELR - Breakers - NSPM	A.0000394.036	Wilmarth-Replace Bkr 5S19	0	0	411	300	0	0	12/15/2023
Asset Renewal	ELR - Breakers - NSPM	A.0000394.016	Souris - Repalce Breaker 5T70	309	225	0	0	0	0	10/31/2022

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2022		2023		2024		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	Date
NSPM Additions										
Asset Renewal	ELR - Breakers - NSPM	A.0000394.032	Rogers Lake-Replace Bkr 5P69	287	210	0	0	0	0	12/15/2021
Asset Renewal	ELR - Breakers - NSPM	A.0000394.043	Arlington Line Bypass	0	0	79	57	0	0	3/31/2023
Asset Renewal	ELR - Breakers - NSPM	A.0000394.034	Wakefield-Replace Bkr 5N28	0	0	20	14	0	0	12/15/2023
Asset Renewal	ELR - Breakers - NSPM	A.0000394.037	Westgate-Replace Bkrs 4M3 & 4M5	0	0	20	14	0	0	12/15/2023
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.004	NSPM Major Line Refurbishment	3,275	2,392	9,848	7,192	9,849	7,193	12/31/2026
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.025	NSM0734 West gate Excelsor Line	4,564	3,333	0	0	0	0	5/15/2022
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.041	NSM5400 ALB-PAT-WAK Refurb	3,489	2,548	0	0	0	0	10/15/2022
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.040	NSM0701 CRO to GFD Refurb	2,651	1,936	0	0	0	0	8/15/2022
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.052	NSM0701 CRO VCT Crow River - Greenfield	855	624	0	0	0	0	8/15/2022
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.039	NSM0735 DLO STB Refurb	509	372	0	0	0	0	3/15/2022
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.038	NSM0735 CAR YAM Refurb	197	144	0	0	0	0	3/15/2022
Asset Renewal	NSPM - Major Line Refurbishment	A.0000498.037	NSM0735 CAR STB Refurb	197	144	0	0	0	0	3/15/2022
Asset Renewal	ELR Nuclear NSPM	A.0001014.001	NSPM - ELR - Nuclear	7,280	5,316	9,321	6,807	4,906	3,583	12/30/2024
Asset Renewal	ELR Nuclear NSPM	A.0001014.007	Monticello TR6 - 336MVA	0	0	0	0	4,996	3,649	9/30/2024
Asset Renewal	ELR Nuclear NSPM	A.0001014.004	Monticello Breakers 5N5,5N6, 7N1	1,931	1,410	0	0	0	0	12/1/2022
Asset Renewal	ELR Nuclear NSPM	A.0001014.006	Monticello Breakers 5N7,5N8, 5N9	0	0	1,798	1,313	0	0	12/15/2023
Asset Renewal	ELR Nuclear NSPM	A.0001014.005	Prairie Island Breakers 6H2, 6H5	1,189	868	0	0	0	0	12/15/2022
Asset Renewal	NSPM Metro Steel pole Rplmnt	A.0000743.010	NSM0810 MST RIV Triple CKT Pole Rplmt	9,559	6,981	5,911	4,317	4,536	3,313	12/15/2025
Asset Renewal	ELR - Relay - NSPM	A.0000395.016	NSPM - 2016 - ELR - Relays	0	0	1,478	1,079	4,236	3,094	12/31/2026
Asset Renewal	ELR - Relay - NSPM	A.0000395.099	Wilmarth LZOP 115kV 5S8, 5S9, 5S10, 5S19	0	0	1,741	1,271	0	0	6/15/2023
Asset Renewal	ELR - Relay - NSPM	A.0000395.076	Riverside Relaying-ELP,FST,MST	1,043	762	0	0	0	0	3/31/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.064	Elliot Park Relaying-MST,RIV	1,029	752	0	0	0	0	3/31/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.101	Prairie LZOP 115kV 5G4, 5G9	0	0	878	641	0	0	6/30/2023
Asset Renewal	ELR - Relay - NSPM	A.0000395.074	Prairie Relaying - NOR1,NOR2	0	0	820	599	0	0	12/15/2023
Asset Renewal	ELR - Relay - NSPM	A.0000395.062	Black Dog Relaying-BLL,BRV,CDV	0	0	765	559	0	0	5/15/2023
Asset Renewal	ELR - Relay - NSPM	A.0000395.075	Riverside Relaying - MOL,TWL	704	514	0	0	0	0	12/15/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.069	Main St Relaying - ELP,RIV	660	482	0	0	0	0	3/31/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.077	Rogers Lake Relaying-AIR	443	323	0	0	0	0	11/15/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.100	Black Dog LZOP 115kV 5M251	439	320	0	0	0	0	12/15/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.102	Riverside LZOP 115kV 5M314	439	320	0	0	0	0	12/15/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.103	Wakefield LZOP WAK 5N27	0	0	438	320	0	0	6/15/2023
Asset Renewal	ELR - Relay - NSPM	A.0000395.105	RED ROCK - LZOP - 115KV_0888_BCK_NSS1	0	0	0	0	436	318	6/30/2024
Asset Renewal	ELR - Relay - NSPM	A.0000395.104	RED ROCK - LZOP - 115KV_0892_BCK2	0	0	0	0	435	318	6/30/2024
Asset Renewal	ELR - Relay - NSPM	A.0000395.061	Airport Relaying - RLK	403	294	0	0	0	0	11/15/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.073	Paynesville Relaying - WAK	0	0	394	288	0	0	11/15/2023
Asset Renewal	ELR - Relay - NSPM	A.0000395.090	Cedarvale Replace Relaying to BDS	369	270	0	0	0	0	12/15/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.071	Moore Lake Relaying - RIV	358	262	0	0	0	0	12/15/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.067	Koch Relaying - JNC	0	0	352	257	0	0	12/31/2023
Asset Renewal	ELR - Relay - NSPM	A.0000395.072	Osseo Relaying - Bus1 TT	0	0	343	250	0	0	12/15/2023
Asset Renewal	ELR - Relay - NSPM	A.0000395.081	Twin Lakes Relaying - RIV	328	239	0	0	0	0	12/15/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.082	Wakefield Relaying - PAT	0	0	291	213	0	0	11/30/2023
Asset Renewal	ELR - Relay - NSPM	A.0000395.083	West Coon Rapids Relaying-ECK	0	0	291	213	0	0	11/30/2023
Asset Renewal	ELR - Relay - NSPM	A.0000395.068	Lincoln Co Relaying - CHC,CEN	141	103	0	0	0	0	12/15/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.106	CHC - GPL New Relay at CHC SD	0	0	0	0	0	0	10/15/2022
Asset Renewal	ELR - Relay - NSPM	A.0000395.107	WSF - GPL New Relay at WSF SD	0	0	0	0	0	0	10/15/2022
Asset Renewal	Line ELR - NSPM	A.0000504.025	NSPM T-Line ELR 2016 69kV, Line	5,029	3,673	5,828	4,256	4,577	3,343	12/15/2026
Asset Renewal	Line ELR - NSPM	A.0000504.043	SD 69kV T-line ELR, Line	101	74	102	74	102	75	12/31/2025
Asset Renewal	Line ELR - NSPM	A.0000504.039	ND 69kV T-line ELR, Line	101	73	100	73	101	73	12/31/2025
Asset Renewal	S&E - NSP Sub	A.0000585.009	NSPM S&E, Sub	4,145	3,027	4,210	3,075	4,154	3,034	12/31/2026

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2022		2023		2024		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	Date
NSPM Additions										
Asset Renewal	S&E - NSP Sub	A.0000585.050	Red Rock Cap 2 115KV BKR	383	280	0	0	0	0	5/1/2022
Asset Renewal	S&E - NSP Sub	A.0000585.013	SD S&E, Sub	64	47	64	47	64	47	12/31/2024
Asset Renewal	S&E - NSP Sub	A.0000585.008	ND S&E, Sub	64	47	64	47	64	47	12/31/2024
Asset Renewal	ELR - Transformers NSPM	A.0000506.002	NSPM ELR Transformers	5,726	4,182	4,009	2,928	2,981	2,177	12/15/2025
Asset Renewal	0953 Replace OPGW	A.0001299.002	NSM0953 NOB SPK REPL OPGW MN	4,211	3,075	0	0	0	0	9/15/2022
Asset Renewal	0953 Replace OPGW	A.0001299.004	NSM0953 NOB LAJ REPL OPGW	0	0	3,663	2,675	0	0	9/1/2023
Asset Renewal	0953 Replace OPGW	A.0001299.003	NSM0953 NOB SPK REPL OPGW (SD)	0	0	987	721	0	0	7/15/2023
Asset Renewal	Tools Line Field Ops	A.0006059.453	Civil Dept Tool B Line	2,000	1,461	2,000	1,461	2,000	1,461	10/30/2026
Asset Renewal	Tools Line Field Ops	A.0006059.085	Tools MN Sub	300	219	300	219	350	256	12/31/2026
Asset Renewal	Tools Line Field Ops	A.0006059.445	Tool Blanket MN, Line	230	168	237	173	245	179	12/31/2026
Asset Renewal	Tools Line Field Ops	A.0006059.496	EPZ Mats MN	250	183	50	37	50	37	12/31/2026
Asset Renewal	Tools Line Field Ops	A.0006059.452	Survey Group Tool B Line	50	37	50	37	50	37	12/31/2026
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.006	NSPM Switch Replacements, Line	491	359	1,576	1,151	2,363	1,726	12/31/2025
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.031	NSM0789 Wells Ck 4H21, 4H22, 4H23, Line	438	320	0	0	0	0	11/30/2022
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.022	NSM0755 Bush Park Muni 4N41, 4N42, & 4N43	416	304	0	0	0	0	11/15/2022
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.056	NSM0793 Villard 4N33 4N34	0	0	354	258	0	0	11/30/2023
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.048	NSM0719 Sleepy Eye City switch #290,291& 292,Li	346	253	0	0	0	0	11/30/2022
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.041	NSPM GRE Switch Replacements 69kV, Line	99	72	98	72	98	72	12/15/2025
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.068	0721 FAX-CAI - REPL STR 198 SW 449 454	240	175	0	0	0	0	12/15/2022
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.066	0721 FAX CAI REPL STR 170 SW 450 453	240	175	0	0	0	0	12/15/2022
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.020	NSM0782 Gleason Lake 4M17	0	0	227	166	0	0	11/30/2023
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.019	NSM0737 Gleason Lake 4M58	0	0	227	166	0	0	11/30/2023
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.035	NSM0733 Reynolds Rpl SW 130 131	63	46	0	0	0	0	4/30/2022
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.070	Avon Line Switch MOD Install - Sub Equip	61	45	0	0	0	0	2/18/2022
Asset Renewal	NSPM Group 1 Switch Replacements	A.0000705.069	Avon Line Switch MOD Install	13	9	0	0	0	0	2/18/2022
Asset Renewal	NSP Reloc B	A.0000276.026	NSPM Reloc B 69kV, Line	1,477	1,079	1,477	1,078	1,477	1,078	12/21/2026
Asset Renewal	NSP Reloc B	A.0000276.033	NSPM Reloc B 115kV, Line	773	564	0	0	0	0	11/15/2023
Asset Renewal	NSP Reloc B	A.0000276.035	ND Reloc B 69kV Line	50	37	50	37	50	37	12/15/2026
Asset Renewal	NSP Reloc B	A.0000276.056	SD Reloc B 69kV, Line	50	37	50	37	50	37	12/15/2026
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.005	NSPM ELR - RTU,Comm	986	720	990	723	985	720	12/31/2026
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.034	Twin Lakes RTU upgrade	408	298	0	0	0	0	4/25/2022
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.035	Red River RTU upgrade	392	286	0	0	0	0	5/13/2022
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.043	Airport RTU upgrade	356	260	0	0	0	0	11/15/2022
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.039	Rogers lake RTU upgrade	355	260	0	0	0	0	11/15/2022
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.032	Indiana RTU upgrade	288	210	0	0	0	0	5/15/2022
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.040	Arlington Comm upgrade	0	0	279	204	0	0	3/31/2023
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.054	Riverside RTU upgrade	71	52	0	0	0	0	12/15/2022
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.046	Carver County RTU upgrade	8	6	0	0	0	0	12/15/2022
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.049	Northfield RTU upgrade	6	5	0	0	0	0	12/15/2022
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.048	Faribault RTU upgrade	6	5	0	0	0	0	12/15/2022
Asset Renewal	RTU - EMS Upgrade - NSPM	A.0000657.047	Aden Hills RTU upgrade	5	4	0	0	0	0	12/15/2022
Asset Renewal	Fault Recorders - NSPM	A.0000393.013	Eden Prairie DFR Shelves	1,159	847	0	0	0	0	5/16/2022
Asset Renewal	Fault Recorders - NSPM	A.0000393.015	Kohlman Lake DFR Shelves	1,123	820	0	0	0	0	6/15/2022
Asset Renewal	Fault Recorders - NSPM	A.0000393.016	Inver Hills DFR Shelves	862	630	0	0	0	0	6/15/2022
Asset Renewal	Fault Recorders - NSPM	A.0000393.014	Elm Creek DFR Shelves	837	611	0	0	0	0	3/30/2022
Asset Renewal	Wilmarth-TC Thru Flow Mitigation	A.0000385.001	Line 0717 GRI to CAR Rbld, Line	0	0	0	0	3,817	2,788	1/6/2024
Asset Renewal	NSPM, Hugo Training Center	A.0000912.002	Hugo Training Center Outside Sub	0	0	3,678	2,686	0	0	12/15/2023
Asset Renewal	Eau Claire 345kV Upgrade	A.0002058.008	0981 King - St Croix River Refb	0	0	3,482	2,543	29	21	12/31/2023
Asset Renewal	Tools COM Substation	A.0006059.449	NSP COM Tool Sub	1,000	730	1,000	730	1,200	876	12/31/2026

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2022		2023		2024		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	Date
NSPM Additions										
Asset Renewal	Tools COM Substation	A.0006059.451	NSPM COM Tools (BU 8640)	135	99	140	102	0	0	12/31/2023
Asset Renewal	Unserviceable Brkr Rplmt Program	A.0000287.018	MN Unserviceable Breaker Replacement, Sub	566	414	567	414	763	557	12/31/2026
Asset Renewal	Unserviceable - Relays - NSPM	A.0000751.003	MN Unserviceable Relay	492	359	493	360	493	360	12/31/2026
Asset Renewal	Pole Treatment Program	A.0001485.008	Pole Treatment Program 69kV MN	410	299	410	299	410	299	12/31/2026
Asset Renewal	Transmission UAV Flights	A.0000855.001	NSPM Transmission UAV	1,045	763	0	0	0	0	12/30/2022
Asset Renewal	MN Subs Capacity - Discrete	A.0010133.086	Elm Creek TR4	611	446	0	0	0	0	6/1/2022
Asset Renewal	Tools System Protection Comm Eng	A.0006059.087	NSPM Sys Protect Comm Eng Testing Eq	100	73	100	73	100	73	12/31/2025
Asset Renewal	Tools, Training Center	A.0006059.447	NSPM Training Center Tools	75	55	75	55	75	55	12/31/2026
Asset Renewal	Tools - Engineering	A.0006059.450	NSP Ops Engineering Tools	60	44	60	44	60	44	12/31/2025
Asset Renewal	Canistota Cap Bank Retirement	A.0001738.001	Canistota Cap Bank Retirement	100	73	0	0	0	0	12/15/2022
Asset Renewal	Sleepy Eye Cap Bank Retirement	A.0001737.001	Sleepy Eye Cap Bank Retirement	100	73	0	0	0	0	12/15/2022
Asset Renewal	Tools STAC	A.0001019.001	NSPM Tools STAC	12	9	12	9	12	9	12/31/2025
Asset Renewal	Tools STAC	A.0001019.003	NSPM STAC Tools	12	9	12	9	12	9	12/31/2025
Asset Renewal	NSPM Solar Gardens	A.0005566.037	0724 Strs. 322-330 Reimb Relocation	10	7	0	0	0	0	2/15/2022
Asset Renewal	Facility Upgrade Ancillary Equip	A.0001273.024	Lafayette Grounding	3	2	0	0	0	0	5/15/2022
Asset Renewal	General Furniture	A.0005014.117	Gen Plt Furniture MN	0	0	0	0	0	0	12/31/2023
Asset Renewal Total				**152,317**	**111,237**	**195,343**	**142,659**	**147,715**	**107,876**	
Reliability Requirement	So Wash Elec Reliab SWERU	A.0000895.004	RRK Sub TR9 & TR10 Replacement	0	0	0	0	12,770	9,326	12/1/2024
Reliability Requirement	So Wash Elec Reliab SWERU	A.0000895.006	Temp By-Pass BCK-RRK	0	0	382	279	0	0	12/1/2023
Reliability Requirement	So Wash Elec Reliab SWERU	A.0000895.003	SWERU Permiting Activities	0	0	76	55	0	0	12/31/2023
Reliability Requirement	Elm Creek TR10	A.0001659.001	Elm Creek TR10	0	0	9,336	6,818	0	0	6/1/2023
Reliability Requirement	TACT	A.0000943.008	2021 NSPM NERC TPL (MN-TACT)	1,001	731	5,006	3,656	0	0	1/1/2027
Reliability Requirement	TACT	A.0000943.007	2020 NSPM NERC TPL(MN-TACT)	4	3	4	3	1,001	731	1/1/2027
Reliability Requirement	Long Lake-Baytown Ln #0801 Uprate	A.0001438.001	LN #0801 Baytown - Long Lake Reconductor	4,912	3,588	0	0	0	0	6/1/2022
Reliability Requirement	Rogers Lake 115 kV Bus Expansion	A.0001666.001	RLK 115 kV Bus Expansion	0	0	3,315	2,421	0	0	5/15/2023
Reliability Requirement	Rogers Lake 115 kV Bus Expansion	A.0001666.002	HBR new 115 kV line terminal	0	0	928	678	0	0	5/15/2023
Reliability Requirement	Rogers Lake 115 kV Bus Expansion	A.0001666.003	5577 HBR-RLK establish new circuit	0	0	416	304	0	0	5/15/2023
Reliability Requirement	Rogers Lake 115 kV Bus Expansion	A.0001666.004	0808 HBR-RLK de-bifurcation	0	0	94	69	0	0	5/15/2023
Reliability Requirement	Lincoln County Capacitor Bank	A.0001184.001	Lincoln Co 30MVAR Cap Bank Sub	1,968	1,437	1,500	1,095	0	0	12/15/2022
Reliability Requirement	Lincoln County Capacitor Bank	A.0001184.003	Lincoln County 30MVAR Cap Bank Comm SD	377	275	0	0	0	0	12/15/2022
Reliability Requirement	DCP Daytons Bluff Sub	A.0001471.005	Daytons Bluff Transmission BKR SW Repl	0	0	0	0	3,007	2,196	12/15/2024
Reliability Requirement	Falls Capacitor Bank	A.0001185.001	Falls 40MVAR Cap Bank Sub	0	0	2,544	1,858	0	0	6/1/2023
Reliability Requirement	DCP Great Plains	A.0010174.004	Great Plains 5503 Line	2,179	1,592	0	0	0	0	12/15/2022
Reliability Requirement	DCP Great Plains	A.0010174.005	Great Plains Sub TAM	0	0	189	138	0	0	5/15/2023
Reliability Requirement	DCP Great Plains	A.0010174.006	Great Plains Comm TAM	3	2	0	0	0	0	5/1/2022
Reliability Requirement	0714:MDE(ITC)MDL(City)Tap Rbld	A.0000727.001	Line 714 rebuild, Line	1,611	1,176	0	0	0	0	12/1/2022
Reliability Requirement	Stockyards Sub	A.0000718.001	Stockyards DCP TR3, Sub	0	0	1,315	960	0	0	10/15/2023
Reliability Requirement	Stockyards Sub	A.0000718.002	0818/5529 Tap Relo, Line	0	0	241	176	0	0	10/15/2023
Reliability Requirement	Elm Creek TR9 Reactor	A.0001677.001	Elm Creek TR9 Reactor	0	0	1,262	921	0	0	6/1/2023
Reliability Requirement	Wilmarth/Mankato Energy Center Trans. Pr	A.0000660.001	ARL Main Bus Reconfig(USE), Sub	0	0	0	0	1,232	900	1/6/2024
Reliability Requirement	Aldrich DCP	A.0000986.001	Aldrich DCP Upgrade Feeders, Sub	0	0	1,045	763	0	0	12/15/2023
Reliability Requirement	PRC-002-2 NERC Compliance	A.0001157.010	Red Rock DFR Shelves	730	533	0	0	0	0	4/15/2022
Reliability Requirement	Larimore Substation Conversion	A.0001129.001	0776 Reterm LAR, Line	0	0	0	0	225	165	11/15/2024
Reliability Requirement	Hatton Sub	A.0000744.001	DCP - Hatton TR, Line	0	0	0	0	153	112	10/31/2024
Reliability Requirement Total				**12,785**	**9,337**	**27,653**	**20,195**	**18,388**	**13,429**	

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2022		2023		2024		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	Date
NSPM Additions										
Comm Infrastructure	Comm Network Program	A.0001320.007	NSPM Comm Network Program Comm	5,922	4,325	23,482	17,149	25,406	18,554	12/15/2026
Comm Infrastructure	Comm Network Program	A.0001320.118	0978 (MNN - ECK) Private Comm Network	2,172	1,586	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.112	0865 (AFT - OPK) Private Comm Network	1,163	849	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.106	0841 (CDV - SOU) Private Comm Network	1,128	824	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.107	0844 (PIK - SCO) Private Comm Network	974	711	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.117	0978 (ECK - PML) Private Comm Network	936	683	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.108	0844 (SAV - PIK) Private Comm Network	875	639	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.125	0782 (GNL - GSL) Private Comm Network	824	602	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.116	0895 (WCR - OSS) Private Comm Network	772	564	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.130	0806 (SLP - ALD) Private Comm Network	711	519	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.110	0845 (WES - TER) Private Comm Network	711	519	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.103	0838 (TLK - OAD) Private Comm Net	635	464	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.100	0822 (0526 tap - IVG) Private Comm Net	622	454	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.124	0734 (BLC - EXC) Private Comm Network	609	445	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.121	5516 (SCO - BLC) Private Comm Network	608	444	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.128	0802 (RPL - RAM) Private Comm Network	521	380	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.119	0978 (PML - PKL) Private Comm Network	494	361	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.126	0782 (WSG - GNL) Private Comm Network	458	334	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.102	0830 (OAD - LLK) Private Comm Net	445	325	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.104	0838 (WDY - TLK) Private Comm Network	432	316	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.133	0821 (MPK - HBR) Private Comm Network	430	314	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.135	0821 (TER - PRR) Private Comm Network	407	297	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.021	Red Rock - Private Comm Network	409	298	0	0	0	0	6/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.105	0841 (BDS - CDV) Private Comm Network	394	288	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.115	0894 (MEL - CEL) Private Comm Network	381	278	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.129	0802 (TER - RPL) Private Comm Network	357	260	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.033	Kohlman Lake - Private Comm Network	362	265	1	1	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.027	0802 RAM KOL Private Comm Network	348	255	0	0	0	0	10/1/2021
Comm Infrastructure	Comm Network Program	A.0001320.111	0846 (HBR - DBL) Private Comm Network	330	241	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.132	0814 (PKL - BCR) Private Comm Network	310	227	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.037	Terminal - Private Comm Network	302	221	10	7	0	0	10/14/2022
Comm Infrastructure	Comm Network Program	A.0001320.109	0845 (DBL - WES) Private Comm Network	281	205	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.036	Rogers Lake - Private Comm Network	271	198	0	0	0	0	4/29/2022
Comm Infrastructure	Comm Network Program	A.0001320.032	Elliot Park - Private Comm Network	263	192	0	0	0	0	3/31/2022
Comm Infrastructure	Comm Network Program	A.0001320.069	Goose Lake - Private Comm Network	256	187	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.072	Long Lake - Private Comm Network	256	187	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.076	Parkers Lake - Private Comm Network	256	187	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.068	Edina - Private Comm Network	256	187	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.078	Scott County - Private Comm Network	256	187	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.070	Gleason Lake - Private Comm Network	256	187	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.073	Midtown - Private Comm Network	256	187	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.080	Westgate - Private Comm Network	256	187	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.074	Nine Mile Creek - Private Comm Network	256	187	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.071	Hiawatha West - Private Comm Network	256	187	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.075	Pike Lake - Private Comm Network	256	187	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.031	Chisago County - Private Comm Network	0	0	261	190	0	0	6/1/2023
Comm Infrastructure	Comm Network Program	A.0001320.123	0526 (LOK - 0822 tap) Private Comm Net	248	181	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.120	5507 (IGV - IVH) Private Comm Network	242	177	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.114	0894 (CEL - SLP) Private Comm Network	230	168	10	7	0	0	12/1/2022

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2022		2023		2024		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	Date
NSPM Additions										
Comm Infrastructure	Comm Network Program	A.0001320.162	Osseo - Private Comm Network	234	171	0	0	0	0	2/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.113	0871 (CNC - WCR) Private Comm Network	204	149	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.131	0814 (BCR - MEL) Private Comm Network	185	135	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.134	0821 (PRR - MPK) Private Comm Network	172	126	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.034	Main Street - Private Comm Network	155	113	0	0	0	0	3/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.101	0827 (OSS - ECK) Private Comm Net	142	103	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.077	Riverside - Private Comm Network	138	100	0	0	0	0	2/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.127	0800 (ASK - W3309 tap) Private Comm Net	96	70	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.019	Prairie Island - Private Comm Network	60	44	0	0	0	0	11/1/2021
Comm Infrastructure	Comm Network Program	A.0001320.017	AS King - Private Comm Network	36	26	0	0	0	0	12/15/2021
Comm Infrastructure	Comm Network Program	A.0001320.020	Rosemount - Private Comm Network	20	15	0	0	0	0	11/15/2021
Comm Infrastructure	Comm Network Program	A.0001320.065	0803 APA-AHI - Private Comm Network	12	9	0	0	0	0	12/1/2021
Comm Infrastructure	Comm Network Program	A.0001320.056	0896 (SLP-EDA) - Private Comm Network	11	8	0	0	0	0	12/1/2021
Comm Infrastructure	Comm Network Program	A.0001320.035	Southtown - Private Comm Network	10	7	0	0	0	0	11/15/2021
Comm Infrastructure	Comm Network Program	A.0001320.039	Wilson - Private Comm Network	10	7	0	0	0	0	11/15/2021
Comm Infrastructure	Comm Network Program	A.0001320.038	Twin Lakes - Private Comm Network	10	7	0	0	0	0	11/15/2021
Comm Infrastructure	Comm Network Program	A.0001320.030	Arden Hills - Private Comm Network	10	7	0	0	0	0	11/15/2021
Comm Infrastructure	Comm Network Program	A.0001320.066	High Bridge - Private Comm Network	5	4	0	0	0	0	12/1/2021
Comm Infrastructure	Comm Network Program	A.0001320.025	0838 RRK-WDY - Private Comm Network	0	0	0	0	0	0	12/1/2021
Comm Infrastructure	Comm Network Program	A.0001320.028	0865 AFT WDY Private Comm Network	0	0	0	0	0	0	12/1/2021
Comm Infrastructure	Comm Network Program	A.0001320.029	5562 LLK KOL Private Comm Network	0	0	0	0	0	0	12/1/2021
Comm Infrastructure	Comm Network Program	A.0001320.026	0801 BYT OPK Private Comm Network	0	0	0	0	0	0	12/1/2021
Comm Infrastructure	NSPM COMM Circuit Upgrades	A.0001357.002	NSPM 2017 COMM Circuit Upgrades	170	124	170	124	170	124	12/31/2025
Communication Infrastructure Total				**31,074**	**22,693**	**24,297**	**17,744**	**25,576**	**18,678**	
Security\Resiliency	Physical Security	A.0000710.004	NSPM Physical Security Sub Infrstruc	0	0	15,496	11,317	9,138	6,674	12/31/2026
Security\Resiliency	Physical Security	A.0000710.010	NSPM Physical Security Comm	3,738	2,730	4,612	3,368	4,612	3,368	12/30/2026
Security\Resiliency	Physical Security	A.0000710.057	Roseau Phy Sec Subs INFRA	4,133	3,018	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.056	Monticello Physical Security Subs INFRA	0	0	2,768	2,022	0	0	12/15/2023
Security\Resiliency	Physical Security	A.0000710.058	Sheyenne Physical Security Subs INFRA	0	0	2,768	2,022	0	0	12/15/2023
Security\Resiliency	Physical Security	A.0000710.085	Souris Physical Security Subs INFRA	2,766	2,020	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.078	Airport Physical Security Subs INFRA	2,766	2,020	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.054	Helena Phy Sec Subs INFRA	2,765	2,019	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.051	Byron Physical Security Subs INFRA	2,758	2,014	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.053	Hampton Phy Sec Subs INFRA	1,394	1,018	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.052	Cottage Grove Phy Security Subs INFRA	880	643	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.083	Rosemount Phy Sec Subs INFRA	853	623	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.080	East Bloomington Phy Security Subs INFRA	853	623	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.081	Farmington Physical Sec Subs INFRA	853	623	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.055	Koch Refinery Phy Sec Subs INFRA	0	0	853	623	0	0	12/15/2023
Security\Resiliency	Physical Security	A.0000710.064	Koch Refinery Phy Sec COMM	0	0	851	622	0	0	12/15/2023
Security\Resiliency	Physical Security	A.0000710.066	Roseau Physical Security COMM	829	606	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.079	Dome Pipeline Phyl Security Subs INFRA	811	592	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.084	Wescott Propane Plt Phy Sec Subs INFRA	811	592	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.065	Monticello Physical Security COMM	0	0	651	475	0	0	12/15/2023
Security\Resiliency	Physical Security	A.0000710.063	Helena Physical Security COMM	648	473	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.060	Byron Physical Security COMM	648	473	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.067	Sheyenne Physical Security COMM	0	0	605	442	0	0	12/15/2023
Security\Resiliency	Physical Security	A.0000710.072	Farmington Physical Sec COMM	599	438	0	0	0	0	12/15/2022

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2022		2023		2024		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPM	MN Jur	NSPM	MN Jur	NSPM	MN Jur	Date
NSPM Additions										
Security\Resiliency	Physical Security	A.0000710.076	Souris Physical Security COMM	599	438	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.074	Rosemount Phy Sec COMM	599	438	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.071	East Bloomington Phy Security COMM	599	438	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.069	Airport Physical Security COMM	599	438	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.075	Wescott Propane Plt Phy Sec COMM	557	407	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.073	Minnesota Pipeline Phy Sec COMM	557	407	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.070	Dome Pipeline Phyl Security COMM	557	407	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.011	NSPM ND Physical Security Comm	453	331	0	0	0	0	9/30/2022
Security\Resiliency	Physical Security	A.0000710.062	Hampton Physical Security COMM	284	208	0	0	0	0	12/15/2022
Security\Resiliency	NERC Order 754 NSPM	A.0000738.015	Chisago 500kV NERC Order 754	0	0	2,373	1,733	0	0	2/28/2023
Security\Resiliency	NERC Order 754 NSPM	A.0000738.009	Parkers Lake 115kV NERC Order 754	0	0	1,522	1,112	0	0	4/30/2023
Security\Resiliency	NERC Order 754 NSPM	A.0000738.013	Red Rock 345kV NERC Order 754 Upgrade	1,394	1,018	0	0	0	0	12/15/2022
Security\Resiliency	NERC Order 754 NSPM	A.0000738.014	Sherco 345kV NERC Order 754	0	0	1,233	901	0	0	12/15/2023
Security\Resiliency	NERC Order 754 NSPM	A.0000738.006	Terminal NERC 754 Add Batteries	0	0	1,208	882	0	0	12/15/2023
Security\Resiliency	NERC Order 754 NSPM	A.0000738.011	Blue Lake 345kV NERC Order 754 Upgrade	0	0	1,005	734	0	0	12/15/2023
Security\Resiliency	NERC Order 754 NSPM	A.0000738.016	Chisago 345kV NERC Order 754	0	0	973	711	0	0	2/28/2023
Security\Resiliency	NERC Order 754 NSPM	A.0000738.010	Parkers Lake 345kV NERC Order 754	569	416	0	0	0	0	12/30/2022
Security\Resiliency	NERC Order 754 NSPM	A.0000738.008	Forbes 500kV NERC Order 754	425	310	0	0	0	0	12/15/2022
Security\Resiliency	OT Cyber Security NSPM	A.0001456.001	Monitoring Logging RTAC MN	1,868	1,364	1,866	1,363	1,180	861	10/31/2024
Security\Resiliency	OT Cyber Security NSPM	A.0001456.002	Asset Management Software MN	748	546	1,028	751	1,862	1,360	12/31/2025
Security\Resiliency	NSPM Physical Security	A.0000745.002	NSPM SD Physical Security Infrsturc	2,896	2,115	0	0	0	0	12/15/2022
Security\Resiliency	NSPM Physical Security	A.0000745.004	NSPM (ND) Physical Security Infrsturc	2,616	1,910	0	0	0	0	12/15/2022
Security\Resiliency	NSPM Electro Mag Pulse (EMP)	A.0000957.005	NSPM Electro Mag Pulse (EMP)	0	0	292	213	0	0	12/31/2023
Physical Security and Resiliency Total				**43,427**	**31,714**	**40,105**	**29,289**	**16,792**	**12,263**	
Interconnection	SFNU MTEP18 NSPM	A.0001378.002	SNFU Development Pre Con	421	307	5,636	4,116	16,170	11,809	1/1/2027
Interconnection	IA Tariff Fund	A.0000076.002	IA Tariff Fund NSP	5,349	3,906	4,005	2,925	4,019	2,935	12/31/2026
Interconnection	Sherco Solar Interconnection*	A.0001769.001	Sherco Solar Sub Inter Sub Upgr	0	0	4,175	3,049	719	525	12/15/2023
Interconnection	G621 Wind Int.	A.0000898.001	G621 Chanarambie Wind Interc Sub Direct	129	94	0	0	0	0	10/15/2022
Interconnection	G621 Wind Int.	A.0000898.002	G621 Chanarambie Wind Interc Sub Network	-45	-33	0	0	0	0	10/15/2022
Interconnection Total				**5,854**	**4,275**	**13,816**	**10,090**	**20,907**	**15,269**	
Regional Expansion	Google Data Center	A.0001365.005	Snuffys Landing Sub	0	0	0	0	12,506	9,133	6/1/2024
Regional Expansion	Google Data Center	A.0001365.001	0827 SCL SNL	1,675	1,224	0	0	0	0	6/15/2022
Regional Expansion	Google Data Center	A.0001365.003	5573 SNL SHC	0	0	0	0	1,255	917	6/1/2024
Regional Expansion	Google Data Center	A.0001365.002	0827 SNL LIB	0	0	0	0	527	385	6/1/2024
Regional Expansion	Google Data Center	A.0001365.004	5574 SNL SHC	0	0	0	0	353	258	6/1/2024
Regional Expansion	Huntley Wilmarth 345*	A.0000835.003	Huntley Wilmarth 345 ROW N/S	1,822	1,331	0	0	0	0	12/31/2021
Regional Expansion	Huntley Wilmarth 345*	A.0000835.004	Huntley Wilmarth 345 Line N/S	1,396	1,019	0	0	0	0	12/31/2021
Regional Expansion Total				**4,893**	**3,574**	**0**	**0**	**14,641**	**10,692**	
NSPM Total				**250,349**	**182,830**	**301,214**	**219,977**	**244,020**	**178,208**	

These capital additions to be recovered in the Transmission Cost Recovery Rider or Renewable Energy Standard Rider but will be moving into base rates with the implementation of final rates in this case.

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2022		2023		2024		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPW	MN JUR	NSPW	MN JUR	NSPW	MN JUR	Date
NSPW Additions										
Asset Renewal	NSPW Major Line Rebuild	A.0000689.004	NSPw Major Line Rebuild, Line	0	0	14,848	10,844	3,094	2,260	12/31/2026
Asset Renewal	NSPW Major Line Rebuild	A.0000689.058	W3441 Rice Lake to Birchwood	0	0	0	0	6,452	4,712	12/15/2024
Asset Renewal	NSPW Major Line Rebuild	A.0000689.030	W3604 Port Wing Rebuild for DIST Sub	0	0	4,820	3,520	0	0	11/1/2023
Asset Renewal	NSPW Major Line Rebuild	A.0000689.041	W3604 STRS 670 to 837	0	0	0	0	3,806	2,779	12/13/2024
Asset Renewal	NSPW Major Line Rebuild	A.0000689.050	W3320 Hawkins to Catawba Rebuild	0	0	3,761	2,746	0	0	4/15/2023
Asset Renewal	NSPW Major Line Rebuild	A.0000689.051	W3320 Catawba to Str 211 Rebuild	0	0	0	0	3,495	2,553	3/29/2024
Asset Renewal	NSPW Major Line Rebuild	A.0000689.047	W3320 STR 54 to Hawkins Rebuild	3,440	2,512	0	0	0	0	11/20/2022
Asset Renewal	NSPW Major Line Rebuild	A.0000689.036	W3408 STR 563 to Nelson	0	0	3,421	2,498	0	0	9/15/2023
Asset Renewal	NSPW Major Line Rebuild	A.0000689.023	W3477 STR 368 MFD 69kV Rebuild Line	3,312	2,419	0	0	0	0	6/13/2022
Asset Renewal	NSPW Major Line Rebuild	A.0000689.035	W3408 GMN Tap to STR 563	2,855	2,085	0	0	0	0	8/20/2022
Asset Renewal	NSPW Major Line Rebuild	A.0000689.065	W3629 STR 84 to Indianhead Rebuild	2,367	1,729	0	0	0	0	7/1/2022
Asset Renewal	NSPW Major Line Rebuild	A.0000689.055	W3205 LaCrosse-Coulee Swamp	0	0	2,138	1,561	0	0	1/15/2023
Asset Renewal	NSPW Major Line Rebuild	A.0000689.040	W3604 STRS 401 to 470	0	0	0	0	1,868	1,364	12/13/2024
Asset Renewal	NSPW Major Line Rebuild	A.0000689.059	W3502 DPC Tap to Barron	0	0	976	713	0	0	12/15/2023
Asset Renewal	NSPW Major Line Rebuild	A.0000689.066	W3629 Berglund Tap to W3630 Rebuild	294	215	0	0	0	0	12/31/2021
Asset Renewal	NSPW Major Line Rebuild	A.0000689.043	W3321 STR 140 to Phillips Tap Rebuild	0	0	0	0	0	0	11/19/2021
Asset Renewal	Eau Claire 345kV Upgrade	A.0002058.006	W3101 St. Croix River - Eau Claire Refb	14,401	10,517	8,544	6,240	8,083	5,903	12/31/2025
Asset Renewal	Eau Claire 345kV Upgrade	A.0002058.007	W3102 Eau Claire - Arpin Refb	6,997	5,110	4,308	3,146	7,751	5,660	12/15/2025
Asset Renewal	NSPW Major Line Refurbishment	A.0000583.003	NSPW Major Line Refurbishment,Line	3,506	2,560	2,396	1,750	2,956	2,159	12/31/2026
Asset Renewal	NSPW Major Line Refurbishment	A.0000583.054	W3304 Three Lakes to Willow River Tap	3,163	2,310	0	0	0	0	2/15/2022
Asset Renewal	NSPW Major Line Refurbishment	A.0000583.053	W3304 Pine Lake to Three Lakes Rebuild	2,941	2,148	0	0	0	0	2/11/2022
Asset Renewal	NSPW Major Line Refurbishment	A.0000583.055	W3309 Willow River to King	0	0	1,709	1,248	0	0	12/9/2023
Asset Renewal	NSPW Major Line Refurbishment	A.0000583.049	W3207 LAX River Swamp	0	0	0	0	1,547	1,130	5/15/2024
Asset Renewal	NSPW Major Line Refurbishment	A.0000583.051	W3201 LAX River Swamp	0	0	0	0	1,516	1,107	5/15/2024
Asset Renewal	S&E - NSPW Line	A.0000495.021	NSPW S&E 69kV, Line	3,463	2,529	3,461	2,527	3,465	2,531	12/31/2026
Asset Renewal	S&E - NSPW Line	A.0000495.026	NSPW Priority Defects 69kV Line	1,552	1,133	1,552	1,133	1,552	1,133	12/15/2026
Asset Renewal	S&E - NSPW Line	A.0000495.024	MI S&E 34.5kV, Line	50	37	50	37	50	37	12/15/2026
Asset Renewal	ELR - Transformers NSPW	A.0000398.006	ELR - ECL TR10 Replacement	3,717	2,715	0	0	0	0	2/15/2022
Asset Renewal	ELR - Transformers NSPW	A.0000398.007	ELR - LAX TR1 Replacement	0	0	3,656	2,670	0	0	5/15/2023
Asset Renewal	ELR - Transformers NSPW	A.0000398.008	ELR - LAX TR2 Replacement	3,516	2,568	0	0	0	0	11/15/2022
Asset Renewal	ELR - Transformers NSPW	A.0000398.009	Marshland TR02	0	0	2,164	1,580	0	0	12/15/2023
Asset Renewal	ELR - Transformers NSPW	A.0000398.002	NSPW ELR Transformers	0	0	0	0	1,900	1,388	12/15/2026
Asset Renewal	ELR - Breakers - NSPW	A.0000397.010	NSPW - 2016 - ELR - Breakers	120	88	2,751	2,009	2,957	2,159	12/31/2026
Asset Renewal	ELR - Breakers - NSPW	A.0000397.027	Marshland-Replace Bkrs	2,906	2,122	3	2	0	0	10/15/2022
Asset Renewal	ELR - Breakers - NSPW	A.0000397.029	Prentice-Replace Bkr 4R6	1,400	1,023	0	0	0	0	8/15/2022
Asset Renewal	ELR - Breakers - NSPW	A.0000397.022	Jackson Co-Replace Bkrs 4L6,4L7,4L8,4L9	1,275	931	0	0	0	0	12/15/2022
Asset Renewal	ELR - Breakers - NSPW	A.0000397.044	Couleee Avenue Oil Breaker 4L3, 4L5	957	699	0	0	0	0	12/15/2022
Asset Renewal	ELR - Breakers - NSPW	A.0000397.023	Lacrosse-Replace Bkrs 4L44,4L45	0	0	819	598	0	0	2/15/2023
Asset Renewal	ELR - Breakers - NSPW	A.0000397.031	T-Corners-Replace Bkr 4E22	712	520	0	0	0	0	3/15/2022
Asset Renewal	ELR - Breakers - NSPW	A.0000397.025	Menomonie-Replace Bkrs 4E63,4E64	670	489	0	0	0	0	6/1/2022
Asset Renewal	ELR - Breakers - NSPW	A.0000397.045	Viroqua Oil Breaker 4L177	355	259	0	0	0	0	12/15/2022
Asset Renewal	ELR - Breakers - NSPW	A.0000397.026	Monroe Co-Replace Bkrs 4L76,4L77	0	0	20	14	0	0	11/15/2023
Asset Renewal	ELR - Breakers - NSPW	A.0000397.041	TRM -Replace Brk 758	3	2	0	0	0	0	11/15/2021
Asset Renewal	ELR - Relay - NSPW	A.0000503.002	NSPW - 2016 - ELR - Relays	98	72	1,962	1,433	2,948	2,153	12/31/2026
Asset Renewal	ELR - Relay - NSPW	A.0000503.024	Cotton School-Relaying ALC,SPL,SEV,Bus1	1,402	1,024	0	0	0	0	5/15/2022
Asset Renewal	ELR - Relay - NSPW	A.0000503.036	T-Corners-Relaying SPE,WIT,MFD,SPL	1,243	908	0	0	0	0	3/15/2022
Asset Renewal	ELR - Relay - NSPW	A.0000503.045	Marshland Relay-LAX,GVW-WIN,WIN,CTV,TR1	1,010	737	3	2	0	0	12/15/2022
Asset Renewal	ELR - Relay - NSPW	A.0000503.028	Jackson Co-Relaying ALC,HAF,MLE	950	694	0	0	0	0	12/15/2022
Asset Renewal	ELR - Relay - NSPW	A.0000503.030	Park Falls-Relaying FLB1,FLB2	0	0	623	455	0	0	11/15/2023
Asset Renewal	ELR - Relay - NSPW	A.0000503.044	Menomonie - Relaying CEF, RLM	379	277	0	0	0	0	6/15/2022
Asset Renewal	ELR - Relay - NSPW	A.0000503.046	VIR -Relaying BLC-GNO,HLB, MOC	54	40	0	0	0	0	12/15/2022
Asset Renewal	ELR - Relay - NSPW	A.0000503.037	Tremval-Relaying ALC,IDP,MLE	7	5	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay - NSPW	A.0000503.029	Jim Falls-Relaying RCL,HYD,HLC	7	5	0	0	0	0	12/15/2021
Asset Renewal	ELR - Relay - NSPW	A.0000503.033	Seven Mile-Relaying ECL,ELS,LON,CTS,SEM	5	4	0	0	0	0	11/15/2021

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2022		2023		2024		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPW	MN JUR	NSPW	MN JUR	NSPW	MN JUR	Date
NSPW Additions										
Asset Renewal	ELR - Relay - NSPW	A.0000503.035	Spokesville-Relaying CTS,TCN,TCN	5	4	0	0	0	0	11/15/2021
Asset Renewal	ELR - Relay - NSPW	A.0000503.023	Cedar Falls-Relaying CLL,ECL,MEN,RCD	3	2	0	0	0	0	11/15/2021
Asset Renewal	ELR - Relay - NSPW	A.0000503.026	Holcombe-Relaying COR-JIM	3	2	0	0	0	0	12/31/2021
Asset Renewal	ELR - Relay - NSPW	A.0000503.042	HYD - Relaying JIM Carrier	2	1	0	0	0	0	10/15/2021
Asset Renewal	Line ELR - NSPW	A.0000327.017	NSPW 69kV Line ELR 2016	3,251	2,374	3,445	2,516	2,954	2,157	12/15/2026
Asset Renewal	Line ELR - NSPW	A.0000327.022	MI 34.5kV TLine ELR Line	50	37	50	37	50	37	12/15/2026
Asset Renewal	W3203 Briggs-LaCrosse Upgrade	A.0002030.002	W3203 Briggs Mayfair Rebuild	0	0	5,322	3,887	0	0	3/15/2023
Asset Renewal	W3203 Briggs-LaCrosse Upgrade	A.0002030.003	W3203 Mayfair-LaCrosse Rebuild	0	0	0	0	3,289	2,402	1/15/2024
Asset Renewal	RTU - EMS Upgrade - NSPW	A.0000423.003	NSPW ELR - RTU,Comm	491	358	981	717	1,963	1,433	12/31/2026
Asset Renewal	RTU - EMS Upgrade - NSPW	A.0000423.017	JAC - RTU Replacement	408	298	0	0	0	0	12/15/2022
Asset Renewal	RTU - EMS Upgrade - NSPW	A.0000423.015	COU - RTU Replacement	376	275	0	0	0	0	6/15/2022
Asset Renewal	RTU - EMS Upgrade - NSPW	A.0000423.016	PNL - RTU Replacement	338	246	0	0	0	0	6/15/2022
Asset Renewal	W3432 LaCrosse-Coulee 69 kV rebuild	A.0001239.001	W3432 LaCrosse-Coulee 69 kV rebuild	0	0	0	0	4,265	3,115	5/15/2024
Asset Renewal	S&E - NSPW Sub	A.0000075.009	NSPW S&E, Sub	1,178	860	1,177	860	1,178	860	12/31/2026
Asset Renewal	S&E - NSPW Sub	A.0000075.008	MI S&E, Sub	49	36	49	36	49	36	12/31/2024
Asset Renewal	NSPW Group 1 Switch Replacements	A.0000444.005	NSPW Switch Rplmts, Line	1,083	791	1,085	792	1,086	793	12/31/2026
Asset Renewal	Unserviceable - Relays - NSPW	A.0000396.003	WI Unserviceable Relay	493	360	491	358	786	574	12/31/2026
Asset Renewal	Unserviceable Brkr Rplmt Program	A.0000287.014	Unserviceable Breaker Replmnts, Sub MI	468	342	467	341	663	484	12/31/2026
Asset Renewal	Unserviceable Brkr Rplmt Program	A.0000287.047	W3612 Pole for Bkr 3R230	0	0	0	0	0	0	3/15/2022
Asset Renewal	NSPW Reloc B	A.0000496.024	NSPW Reloc B 69kV Line	384	281	384	281	384	281	12/15/2026
Asset Renewal	NSPW Reloc B	A.0000496.022	MI Reloc B 34.5kV Line	50	37	50	37	50	37	12/15/2026
Asset Renewal	Ironwood EEE	A.0001692.001	IRW EEE	0	0	996	727	0	0	12/15/2023
Asset Renewal	Tools COM Substation	A.0006059.431	NSPW Com Tool	313	229	268	196	256	187	12/31/2026
Asset Renewal	Pole Treatment Program	A.0001485.014	Pole Treatment Program 69kV WI	230	168	230	168	230	168	12/31/2025
Asset Renewal	Transmission UAV Flights	A.0000855.002	NSPW Transmission UAV	629	459	0	0	0	0	10/15/2022
Asset Renewal	Unserviceable - Breakers - NSPW	A.0000287.046	Park Falls RPLC 3R230 Reg & Bkr	520	380	0	0	0	0	3/15/2022
Asset Renewal	ELR - Reactors	A.0001461.002	Briggs TR09 Reactor	436	318	0	0	0	0	3/15/2022
Asset Renewal	Tools Line Field Ops	A.0006059.430	Tool Blanket WI, Line	77	56	91	66	85	62	12/31/2026
Asset Renewal	Tools Line Field Ops	A.0006059.497	EPZ Mats NSPW	50	37	50	37	50	37	12/31/2026
Asset Renewal	WI Subs Asset Health - Discrete	A.0010128.016	W3442 at Genoa Sub DCP	302	220	0	0	0	0	10/14/2022
Asset Renewal	Tools STAC	A.0001019.004	NSPW STAC Tools	12	9	12	9	15	11	12/31/2025
Asset Renewal Total				**80,328**	**58,664**	**79,134**	**57,792**	**70,794**	**51,701**	
Reliability Requirement	Bayfield Loop	A.0000193.014	Bayfield Second Circ W3601 Rebuild	14,893	10,877	0	0	0	0	2/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.009	Bayfield Second Circuit-W3603 Rebld	13,587	9,922	532	389	0	0	12/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.007	Bayfield Second Circuit-FSC TAM	7,543	5,508	0	0	0	0	2/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.006	Bayfield Second Circuit-PKC TAM	4,502	3,288	80	58	0	0	12/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.013	Bayfield Second Circ Tie Switch PKC	991	724	34	25	0	0	12/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.012	Bayfield Second Circ FSC-Tie Switch	965	705	0	0	0	0	2/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.021	Bayfield Second Circuit - BFT-STS Reterm	652	476	0	0	0	0	2/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.010	Bayfield Second Circuit-W3604 Reterm	199	145	8	6	0	0	12/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.008	Bayfield Second Circuit-W3602 Reterm	195	143	8	6	0	0	12/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.020	Bayfield Second Circ-FSC Comm	179	131	0	0	0	0	2/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.019	Bayfield Second Circ-PKC Comm	119	87	42	30	0	0	12/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.022	Bayfield Second Circuit - W3648 Str Rpl	72	53	0	0	0	0	2/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.016	Bayfield Second Circ-W3604 ROW	55	40	0	0	0	0	5/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.017	Bayfield Second Circ-W3602 ROW	55	40	0	0	0	0	5/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.024	Bayfield Second Circuit - IRR	15	11	0	0	0	0	2/15/2022
Reliability Requirement	Bayfield Loop	A.0000193.023	Bayfield Second Circuit - BFT	12	9	0	0	0	0	2/15/2022
Reliability Requirement	Jim Falls-Holcombe	A.0001690.001	W3301 Jim Falls-Holcombe	0	0	0	0	10,916	7,972	12/31/2024
Reliability Requirement	Hurley Norrie 115kV	A.0001169.004	HUR 115kV Yard Improvements	0	0	4,098	2,993	65	48	12/15/2023
Reliability Requirement	Hurley Norrie 115kV	A.0001169.003	NRR 115kV Yard Improvements	0	0	2,854	2,084	59	43	12/15/2023
Reliability Requirement	Hurley Norrie 115kV	A.0001169.001	Hurley - Norrie 115kV	0	0	2,258	1,649	0	0	12/15/2023
Reliability Requirement	Hurley Norrie 115kV	A.0001169.002	Hur NRR 115kV MI 1.2 Miles	0	0	1,398	1,021	0	0	12/15/2023

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2022		2023		2024		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPW	MN JUR	NSPW	MN JUR	NSPW	MN JUR	Date
NSPW Additions										
Reliability Requirement	Western WI / E. Metro Upgrade	A.0001437.002	Willow River Sub 20 MVAR CAP	0	0	0	0	7,431	5,427	12/30/2024
Reliability Requirement	DCP Elmwood Substation	A.0010163.003	DCP Elmwood Substation	4,091	2,988	0	0	0	0	5/16/2022
Reliability Requirement	DCP Elmwood Substation	A.0010163.005	W3415 Reterm to ELM Sub	1,308	955	0	0	0	0	5/15/2022
Reliability Requirement	DCP Elmwood Substation	A.0010163.007	W3466 RLM to ELM Sub	532	389	0	0	0	0	5/15/2022
Reliability Requirement	DCP Elmwood Substation	A.0010163.006	W3466 MEN to ELM Sub	355	259	0	0	0	0	5/15/2022
Reliability Requirement	DCP Elmwood Substation	A.0010163.004	W3466 In Out at ELM Sub	128	93	0	0	0	0	12/15/2022
Reliability Requirement	DCP Elmwood Substation	A.0010163.009	Elmwood Substation 69kV Sub COMM	115	84	0	0	0	0	5/15/2022
Reliability Requirement	Bayfront to Ironwood 88 kV	A.0000567.006	W3351 BFT - IRW ROW	1,775	1,296	2,225	1,625	0	0	12/15/2023
Reliability Requirement	Bayfront to Ironwood 88 kV	A.0000567.009	BFT IRW Permit Line SAP	819	598	0	0	0	0	12/31/2022
Reliability Requirement	TACT	A.0000943.023	NSPW NERC TPL (TACT)	0	0	0	0	2,504	1,829	1/1/2027
Reliability Requirement	Boyd Sub Removal DCP	A.0000057.002	Boyd Sub Cap Bank Replacement	1,452	1,061	0	0	0	0	10/15/2022
Reliability Requirement	Boyd Sub Removal DCP	A.0000057.001	W3418 Boyd Sub Rem DCP	185	135	0	0	0	0	10/15/2022
Reliability Requirement	MAF - TR3 Addition	A.0005523.001	MAF - TR3 Addition - DCP	0	0	1,517	1,108	0	0	12/15/2023
Reliability Requirement	Rest Lake-Presque Isle	A.0001198.001	Rest Lake Presque Isle ROW	150	110	400	292	120	88	4/15/2024
Reliability Requirement	Install Turtle Lake Area Substation	A.0001395.004	W3429 Pine Street to Twin Town	0	0	308	225	0	0	8/15/2023
Reliability Requirement	ROW by Permit	A.0000879.002	NSPW USDA F S Ottawa MI 22 26 ROW	80	58	0	0	0	0	1/15/2022
Reliability Requirement	NSPW Galloping Conductors	A.0000762.001	NSPW 2019 Galloping Mitigation	49	36	0	0	0	0	12/15/2022
Reliability Requirement	Spare Breakers	A.0001487.004	NSPW_Spare Breakers	5	4	0	0	0	0	12/31/2021
Reliability Requirement	Twin Town Area Upgrades	A.0001159.002	Turtle Lake - Almena Line	-470	-343	0	0	0	0	11/15/2021
Reliability Requirement Total				**54,610**	**39,882**	**15,762**	**11,511**	**21,095**	**15,406**	
Comm Infrastructure	Comm Network Program	A.0001320.010	NSPW Comm Network Program Comm	246	179	14,555	10,630	15,806	11,543	1/1/2027
Comm Infrastructure	Comm Network Program	A.0001320.087	W3410 (ELL - PRE) - Private Comm Network	2,226	1,626	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.095	W3431 (RIC - PNL) - Private Comm Network	2,036	1,487	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.083	W3309 (WLR-0800 tap) - Private Comm	1,266	924	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.081	W3304 (THL - WLR) - Private Comm Network	1,253	915	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.082	W3304 (PNL-THL) - Private Comm Network	1,195	872	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.091	W3412 (BAY - HSS) - Private Comm Network	1,089	795	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.093	W3429 (CLL - LKC) - Private Comm Network	1,064	777	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.084	W3408 (SHW - LFN) - Private Comm	874	638	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.088	W3410 (HSS - ELL) - Private Comm Network	798	583	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.097	W3484 (OTC - ECL) - Private Comm Network	690	504	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.094	W3429 (LKC - TUR) - Private Comm Network	622	454	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.098	W3485 (ELS - OTC) - Private Comm Network	470	343	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.086	W3408 (WAB - NEL) - Private Comm Network	344	251	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.047	Wheaton - Private Comm Network	342	250	0	0	0	0	6/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.048	Red Cedar - Private Comm Network	338	247	0	0	0	0	6/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.049	Eau Claire - Private Comm Network	323	236	0	0	0	0	6/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.050	Clear Lake - Private Comm Network	323	236	0	0	0	0	6/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.051	Cedar Falls - Private Comm Network	318	232	0	0	0	0	6/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.092	W3428 (SNN - RIC) - Private Comm Network	306	223	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.090	W3412 (0759 tap - BAY) - Private Comm	205	149	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.099	W3485 (SHW - ELS) - Private Comm Network	147	107	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.096	W3453 (ECL - STE) - Private Comm Network	122	89	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.085	W3408 (SYP - W3408 tap) - Private Comm	40	30	10	7	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.052	W3428 (CLL-SNN) - Private Comm Network	49	36	0	0	0	0	11/1/2021
Comm Infrastructure	Comm Network Program	A.0001320.089	W3410 (PRE - 0704 tap) - Private Comm	20	15	5	4	0	0	12/1/2022
Comm Infrastructure	Comm Network Program	A.0001320.057	W3213 (RCD-WHT) - Private Comm Network	11	8	0	0	0	0	12/1/2021
Comm Infrastructure	Comm Network Program	A.0001320.053	W3408 (MAD-SHW) - Private Comm Network	10	7	0	0	0	0	11/5/2021
Comm Infrastructure	Comm Network Program	A.0001320.122	W3215 (CRY-RCD) - Private Comm Network	10	7	0	0	0	0	12/1/2021
Comm Infrastructure	NSPW COMM Circuit Upgrades	A.0000487.001	NSPW 2017 COMM Circuit Upgrades	171	125	170	124	170	124	12/31/2025
Comm Infrastructure	Cedar Falls Relaying - COMM	A.0001481.001	Cedar Falls Relaying - COMM	3	2	0	0	0	0	11/15/2021
Comm Infrastructure	Spokesville Relaying - COMM	A.0001482.001	Spokesville Relaying - COMM	2	1	0	0	0	0	11/15/2021
Communications Infrastructure Total				**16,911**	**12,350**	**14,892**	**10,876**	**15,976**	**11,667**	

Transmission Capital Plant Additions

Addition Amounts Represent Total Project Costs Including AFUDC

				Addition Amount ($000s)						
				2022		2023		2024		In-Service
Capital Budget Groupings	Project Name	WBS Level 2 #	Description	NSPW	MN JUR	NSPW	MN JUR	NSPW	MN JUR	Date
NSPW Additions										
Security\Resiliency	Physical Security	A.0000710.002	NSPW Physical Security Sub Infrstruc	1,115	814	2,011	1,468	2,323	1,697	12/15/2026
Security\Resiliency	Physical Security	A.0000710.086	Camp McCoy Physical SEC Subs INFRA	1,815	1,326	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.059	Eau Claire Phy Sec Subs INFRA	1,210	884	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.006	NSPW Physical Security Comm	202	148	150	110	150	110	12/25/2026
Security\Resiliency	Physical Security	A.0000710.077	Camp McCoy Physical Sececurity COMM	303	221	0	0	0	0	12/15/2022
Security\Resiliency	Physical Security	A.0000710.068	Eau Claire Physical Security COMM	206	150	0	0	0	0	12/15/2022
Security\Resiliency	OT Cyber Security NSPW	A.0001457.001	Monitoring Logging RTAC WI	485	354	485	354	307	224	10/31/2024
Security\Resiliency	OT Cyber Security NSPW	A.0001457.002	Asset Management Software WI	241	176	332	242	601	439	12/31/2025
Security\Resiliency	OT Cyber Security NSPW	A.0001457.006	EAU CLAIRE 345 RTAC Install	44	32	0	0	0	0	3/15/2022
Security\Resiliency	OT Cyber Security NSPW	A.0001457.014	PINE LAKE RTAC Install	44	32	0	0	0	0	2/15/2022
Security\Resiliency	OT Cyber Security NSPW	A.0001457.005	EAU CLAIRE RTAC Install	43	32	0	0	0	0	3/15/2022
Security\Resiliency	OT Cyber Security NSPW	A.0001457.009	MARSHLAND RTAC Install	43	32	0	0	0	0	4/15/2022
Security\Resiliency	OT Cyber Security NSPW	A.0001457.010	PARK FALLS RTAC Install	43	32	0	0	0	0	4/15/2022
Security\Resiliency	OT Cyber Security NSPW	A.0001457.007	JEFFERS ROAD RTAC Install	43	32	0	0	0	0	3/15/2022
Security\Resiliency	OT Cyber Security NSPW	A.0001457.008	LA CROSSE RTAC Install	43	32	0	0	0	0	3/15/2022
Security\Resiliency	OT Cyber Security NSPW	A.0001457.011	RED CEDAR RTAC Install	43	32	0	0	0	0	2/15/2022
Security\Resiliency	OT Cyber Security NSPW	A.0001457.012	WHEATON RTAC Install	43	31	0	0	0	0	2/15/2022
Physical Security and Resiliency Total				**5,967**	**4,357**	**2,977**	**2,174**	**3,381**	**2,469**	
Interconnection	IA Tariff Fund	A.0000076.003	IA Tariff Fund NSPW	2,584	1,887	3,039	2,219	3,106	2,268	12/31/2026
Interconnection	SFNU WI	A.0001463.001	SFNU WI Pre Con	34	25	728	532	3,046	2,225	10/31/2026
Interconnection	DPC Arkansaw Tap Interconnection	A.0001177.001	W3415 Tap to DPC at Arkansaw Sub	944	690	0	0	0	0	4/15/2022
Interconnection	DPC Switch Interconnections	A.0000873.008	DPC W3408 Interconnection	336	245	0	0	0	0	2/25/2022
Interconnection Total				**3,898**	**2,846**	**3,767**	**2,751**	**6,152**	**4,493**	
Regional Expansion	LaCrosse - Madison 345kv*	A.0000306.008	3104 Lax-Mad 345 N/S ROW	1,032	753	696	508	0	0	12/31/2019
Regional Expansion	LaCrosse - Madison 345kv*	A.0000306.002	LAX-MAD New 345kV Non Shared,Line	-222	-162	0	0	0	0	12/31/2018
Regional Expansion Total				**810**	**591**	**696**	**508**	**0**	**0**	
NSPW Total				**162,523**	**118,691**	**117,229**	**85,612**	**117,398**	**85,736**	

Major Line Rebuild Projects (NSPM and NSPW)
Capital Additions (Includes AFUDC)
(Dollars in Millions)

Project Name	2022	2023	2024
NSPM Major Line Rebuild,Line	$0.0	$52.1	$56.2
NSPW Major Line Rebuild, Line	$0.0	$14.8	$3.1
0761 LAK ZUM Rebuild	$8.5	$0.0	$0.0
NSM0703 FRM PKN Rebuild	$7.7	$0.0	$0.0
0723 Atwater - Cosmos (GRE)	$0.0	$0.0	$7.4
NSM0730 - West Sioux Falls - Line 729	$0.3	$6.5	$0.0
NSM0752 Belgrade - Paynesville Rebuild	$6.8	$0.0	$0.0
W3441 Rice Lake to Birchwood	$0.0	$0.0	$6.5
0723 Bird Island - Lake Lillian	$0.0	$5.6	$0.0
NSM0790 Dassel-Cokato Rebuild	$5.5	$0.0	$0.0
W3604 Port Wing Rebuild for DIST Sub	$0.0	$4.8	$0.0
NSPM 0795 Wobegon Trail - Albany	$0.0	$4.7	$0.1
NSM0790 Cokato - Howard Lake Rebuild	$0.0	$0.0	$4.7
NSM0790 Victor - Winsted Rebuild	$0.0	$4.5	$0.0
NSM0790 Victor - 4N185 Rebuild	$0.0	$4.2	$0.0
NSPM 0795 Avon - Albany	$4.2	$0.0	$0.0
0723 Cosmos (GRE) - Lake Lillian	$0.0	$3.9	$0.0
W3604 STRS 670 to 837	$0.0	$0.0	$3.8
W3320 Hawkins to Catawba Rebuild	$0.0	$3.8	$0.0
W3320 Catawba to Str 211 Rebuild	$0.0	$0.0	$3.5
W3320 STR 54 to Hawkins Rebuild	$3.4	$0.0	$0.0
W3408 STR 563 to Nelson	$0.0	$3.4	$0.0
W3477 STR 368 MFD 69kV Rebuild Line	$3.3	$0.0	$0.0
NSPM 0795 St. John's - Watab River	$3.3	$0.0	$0.0
W3408 GMN Tap to STR 563	$2.9	$0.0	$0.0
NSM0794 BLD DGC Rebuild	$2.8	$0.0	$0.0
NSM0752 Belgrade - Paynesville PH2	$2.7	$0.0	$0.0
NSM5401 MLK WAK Rebuild	$2.4	$0.0	$0.0
W3629 STR 84 to Indianhead Rebuild	$2.4	$0.0	$0.0
W3205 LaCrosse-Coulee Swamp	$0.0	$2.1	$0.0
W3604 STRS 401 to 470	$0.0	$0.0	$1.9
NSPM 0795 Avon - Brockway Tap	$0.0	$1.8	$0.0
NSM0779 - Canisota Juntion - Salem,Line	$1.8	$0.0	$0.0
NSM0893 BCK RRK REBLD STRS 14 TO 20	$0.0	$1.6	$0.0
NSPM 0795 St. Joseph - Westwood Tap	$0.0	$1.3	$0.0
NSM0892 BCK RRK REBLD STRS 14 TO 20	$0.0	$1.1	$0.0
W3502 DPC Tap to Barron	$0.0	$1.0	$0.0
NSM0703 FRM NOF Rebuild	$0.9	$0.0	$0.0
NSPM 0795 Watab River - St. Joseph	$0.0	$0.7	$0.0
NSPM 0795 Brockway Tap - St. John's	$0.0	$0.6	$0.0
NSPM 0795 Westwood Tap - West St. Cloud	$0.0	$0.6	$0.0
NSPM0729 CEN LCO 69kV Rebuild	$0.5	$0.0	$0.0
NSPM 0795 Riverview - Wobegon Trail	$0.0	$0.4	$0.0
W3629 Berglund Tap to W3630 Rebuild	$0.3	$0.0	$0.0
NSM0779 STR 231 - Salem Rebuild	$0.0	$0.3	$0.0
0726 Pipestone-Rock Ck-Wdstk rebuild	$0.0	$0.1	$0.0
NSM0754 Becker - Linn Street Rebuild	$0.0	$0.0	$0.0
0741 Litchfield city tap-Atwater	$0.0	$0.0	$0.0
0741 Big Swan - Litchfield city tap	$0.0	$0.0	$0.0
W3321 STR 140 to Phillips Tap Rebuild	$0.0	$0.0	$0.0
Total	**$59.6**	**$120.0**	**$87.1**

Transmission's O&M Costs by Category: 2018-2024

Transmission's O&M Costs by Category: 2018-2024 NSPM-Electric ($000,000)								
Cost Category	**2018 Actual**	**2019 Actual**	**2020 Actual**	**2018 – 2020 Average**	**2021 Forecast**	**2022 Budget**	**2023 Budget**	**2024 Budget**
Internal Labor	$22.0	$20.4	$18.1	$20.1	$18.1	$18.8	$19.4	$20.0
Contract Labor and Consulting	$4.5	$4.5	$4.1	$4.4	$3.8	$3.5	$3.5	$3.5
Employee Expenses	$2.9	$2.7	$1.8	$2.5	$1.8	$2.0	$2.0	$2.0
Fees	$3.5	$3.4	$3.5	$3.5	$3.6	$3.6	$3.6	$3.6
Materials	$3.3	$2.5	$2.1	$2.6	$1.8	$2.3	$2.3	$2.3
Other	$4.1	$2.6	$1.2	$2.6	$1.7	$1.4	$1.4	$1.4
Total	**$40.3**	**$36.1**	**$30.8**	**$35.7**	**$30.8**	**$31.6**	**$32.2**	**$32.8**

NSP System Transmission Expenses ($000's)

Description	2020 ACTUALS (000's)	2022 BUDGET (000's)	2023 BUDGET (000's)	2024 BUDGET (000's)
NSP JPZ payments and GRE JPZ charges	$ 47,798	$ 59,738	$ 60,079	$ 61,247
MISO Network Service	$ 10,832	$ 12,106	$ 12,430	$ 12,712
MISO Transmission Expansion Plan (RECB)	$ 125,205	$ 131,747	$ 127,481	$ 125,414
Schedule 2 (Reactive Supply)	$ 9,318	$ 9,497	$ 9,489	$ 9,440
MISO Schedules 10, 10-FERC	$ 11,394	$ 13,415	$ 13,770	$ 14,111
MISO Schedules 16 and 17	$ 9,140	$ 8,023	$ 8,235	$ 8,418
MISO Schedule 24	$ 1,246	$ 1,168	$ 1,203	$ 1,239
Schedule 1 (Sch, Sys Ctrl & Disp)	$ 595	$ 285	$ 292	$ 299
Sch 33 - Blackstart	$ 30	$ 31	$ 32	$ 33
Sch 45 - NREAC Recovery	$ 2	$ 2	$ 2	$ 2
Other native load deliveries	$ 70	$ 191	$ 191	$ 190
SPP Point-to-Point	$ 58	$ 75	$ 78	$ 80
MISO Point-to-Point	$ 80	$ 100	$ 103	$ 107
MISO System Studies	$ 80	$ 31	$ 32	$ 33
Self-Funded Network Upgrades	$ 518	$ 4,678	$ 4,814	$ 4,814
Courtenay Wind Project - Point-to-Point and Interconnection Upgrades	$ 1,708	$ 1,708	$ 1,708	$ 1,708
Total Expense	**$ 218,075**	**$ 242,796**	**$ 239,940**	**$ 239,847**
Less:				
MISO Schedules 10, 10-FERC - Regional Markets portion	$ 254	$ 298	$ 306	$ 313
MISO Schedules 16 and 17	$ 9,140	$ 8,023	$ 8,235	$ 8,418
MISO Schedule 24	$ 1,246	$ 1,168	$ 1,203	$ 1,239
Note: Regional Markets Items [See Note #1]	**$ 10,639**	**$ 9,489**	**$ 9,744**	**$ 9,970**
MISO Transmission Expansion Plan (RECB)	$ 125,205	$ 131,747	$ 127,481	$ 125,414
Note: Items Collected through TCR	**$ 125,205**	**$ 131,747**	**$ 127,481**	**$ 125,414**
Blazing Star 2 Wind Project	**$ -**	**$ 2,317**	**$ 2,442**	**$ 2,442**
Blazing Star 1 Wind Project	**$ 12**	**$ 34**	**$ 46**	**$ 46**
Dakota Range 1 & 2 Wind Project	**$ 331**	**$ 920**	**$ 920**	**$ 920**
Fox Tail Wind Farm	**$ 176**	**$ 790**	**$ 790**	**$ 790**
Freeborn Wind Farm	**$ -**	**$ 400**	**$ 400**	**$ 400**
Courtenay Wind Project - Point-to-Point and Interconnection Upgrades	**$ 1,708**	**$ 1,708**	**$ 1,708**	**$ 1,708**
Note: Items Collected through RES	**$ 2,227**	**$ 6,169**	**$ 6,306**	**$ 6,306**
Net Base Rate Transmission Expense	**$ 80,004**	**$ 95,390**	**$ 96,409**	**$ 98,158**

Note #1
MISO energy and ancillary services market administration charges are reflected in Commercial Operations portion of Energy Supply budget and included in base rates.

NSP System Transmission Revenues ($000's)

Description	2020 ACTUALS (000's)	2022 BUDGET (000's)	2023 BUDGET (000's)	2024 BUDGET (000's)
Network JPZ - GRE/SMMPA/MRES	$ 48,635	$ 58,624	$ 60,198	$ 61,917
Network Service - Midwest ISO Tariff	$ 31,983	$ 30,974	$ 31,903	$ 32,859
MISO Transmission Expansion Plan (RECB)	$ 132,962	$ 137,424	$ 135,072	$ 133,558
Point-to-Point Firm, Point-to-Point Non Firm	$ 6,706	$ 6,152	$ 6,158	$ 6,163
Schedule 2 (Reactive Supply)	$ 8,176	$ 8,492	$ 8,492	$ 8,492
Tm-1 GFAs	$ -	$ -	$ -	$ -
Fixed GFA Contracts	$ 426	$ 437	$ 438	$ 440
Self-Funded Network Upgrades	$ 201	$ 5,214	$ 5,453	$ 5,660
MISO Schedule 24 - Balancing Authority	$ 1,088	$ 1,254	$ 1,293	$ 1,332
Schedule 1 (Sch, Sys Ctrl & Disp)	$ 730	$ 666	$ 666	$ 666
GRE O&M service	$ 224	$ 224	$ 224	$ 224
Marshall and MMPA TOPS Agreements	$ 140	$ 169	$ 173	$ 178
Transmission Owner Interconnection Facilities - O&M	$ -	$ 501	$ 501	$ 501
Total Revenue Collected	**$ 231,272**	**$ 250,130**	**$ 250,570**	**$ 251,988**
Less:				
Schedule 2 (Reactive Supply)	$ 8,176	$ 8,492	$ 8,492	$ 8,492
Note: Revenues transfer to Energy Supply	**$ 8,176**	**$ 8,492**	**$ 8,492**	**$ 8,492**
MISO Transmission Expansion Plan (RECB)	$ 132,962	$ 137,424	$ 135,072	$ 133,558
Note: Included as credit in TCR Rider	**$ 132,962**	**$ 137,424**	**$ 135,072**	**$ 133,558**
GRE O&M service	$ 224	$ 224	$ 224	$ 224
Marshall and MMPA TOPS Agreements	$ 140	$ 169	$ 173	$ 178
Note: Revenues transfer to Distribution	**$ 365**	**$ 393**	**$ 397**	**$ 401**
Net Base Rate Transmisison Revenue	**$ 89,770**	**$ 103,822**	**$ 106,610**	**$ 109,538**

Joint Zonal Revenues and Expenses - 2022 Budget Year

Revenue

NSP JPZ	GRE	SMMPA	MRES	Total
Jan-22	$ 3,268,666	$ 535,669	$ 497,850	$ 4,302,186
Feb-22	$ 2,947,123	$ 526,075	$ 459,720	$ 3,932,918
Mar-22	$ 2,957,131	$ 514,246	$ 473,624	$ 3,945,002
Apr-22	$ 2,582,713	$ 477,486	$ 434,928	$ 3,495,128
May-22	$ 3,377,859	$ 579,570	$ 475,043	$ 4,432,472
Jun-22	$ 3,976,326	$ 702,285	$ 530,052	$ 5,208,663
Jul-22	$ 4,134,462	$ 803,375	$ 572,563	$ 5,510,400
Aug-22	$ 4,173,012	$ 743,215	$ 557,802	$ 5,474,028
Sep-22	$ 3,594,859	$ 634,983	$ 506,633	$ 4,736,475
Oct-22	$ 2,794,207	$ 557,769	$ 473,284	$ 3,825,260
Nov-22	$ 3,028,546	$ 505,043	$ 465,489	$ 3,999,078
Dec-22	$ 3,309,387	$ 542,711	$ 494,373	$ 4,346,470
Total	**$ 40,144,290**	**$ 7,122,427**	**$ 5,941,363**	**$ 53,208,080**

GRE JPZ	GRE
Jan-22	$ 457,855
Feb-22	$ 460,487
Mar-22	$ 405,770
Apr-22	$ 360,705
May-22	$ 404,611
Jun-22	$ 539,046
Jul-22	$ 568,187
Aug-22	$ 536,928
Sep-22	$ 457,134
Oct-22	$ 370,026
Nov-22	$ 410,598
Dec-22	$ 444,950
Total	**$ 5,416,298**

Total GRE Revenue **$ 45,560,588.63**

Total Transmission Joint Zonal Revenue **$58,624,379**

Expense

NSP JPZ	GRE	SMMPA	CMMPA	NWEC	MMPA	MRES	RPU	Total
Jan-22	$ 2,731,591	$ 1,093,555	$ 115,668	$ 43,018	$ 91,529	$ 121,861	$ 155,190	$ 4,352,413
Feb-22	$ 2,396,958	$ 959,590	$ 101,498	$ 37,748	$ 80,316	$ 106,933	$ 136,179	$ 3,819,222
Mar-22	$ 2,349,843	$ 940,728	$ 99,503	$ 37,006	$ 78,738	$ 104,831	$ 133,502	$ 3,744,150
Apr-22	$ 2,120,624	$ 848,963	$ 89,797	$ 33,396	$ 71,057	$ 94,605	$ 120,479	$ 3,378,921
May-22	$ 2,779,029	$ 1,112,546	$ 117,677	$ 43,765	$ 93,119	$ 123,978	$ 157,885	$ 4,427,998
Jun-22	$ 3,525,083	$ 1,411,219	$ 149,269	$ 55,514	$ 118,117	$ 157,260	$ 200,271	$ 5,616,732
Jul-22	$ 4,071,847	$ 1,630,109	$ 172,421	$ 64,124	$ 136,438	$ 181,653	$ 231,334	$ 6,487,926
Aug-22	$ 3,840,893	$ 1,537,649	$ 162,641	$ 60,487	$ 128,699	$ 171,349	$ 218,213	$ 6,119,932
Sep-22	$ 3,250,539	$ 1,301,309	$ 137,643	$ 51,190	$ 108,918	$ 145,013	$ 184,673	$ 5,179,285
Oct-22	$ 2,520,294	$ 1,008,966	$ 106,721	$ 39,690	$ 84,449	$ 112,435	$ 143,186	$ 4,015,741
Nov-22	$ 2,513,387	$ 1,006,201	$ 106,429	$ 39,581	$ 84,218	$ 112,127	$ 142,793	$ 4,004,736
Dec-22	$ 2,827,155	$ 1,131,813	$ 119,715	$ 44,523	$ 94,731	$ 126,125	$ 160,619	$ 4,504,680
Total	**$ 34,927,243**	**$ 13,982,647**	**$ 1,478,983**	**$ 550,042**	**$ 1,170,329**	**$ 1,558,169**	**$ 1,984,323**	**$ 55,651,736**

GRE JPZ	GRE
Jan-22	$ 366,824
Feb-22	$ 311,472
Mar-22	$ 352,570
Apr-22	$ 277,665
May-22	$ 259,327
Jun-22	$ 376,367
Jul-22	$ 421,485
Aug-22	$ 410,171
Sep-22	$ 302,765
Oct-22	$ 320,287
Nov-22	$ 324,893
Dec-22	$ 362,226
Total	**$ 4,086,051**

Total GRE Expense **$ 39,013,294.11**

Total Transmission Joint Zonal Expense **$ 59,737,788**

Net Transmission Joint Zonal **($1,113,409)**

Net Transmission Joint Zonal Payment for NSP Pricing Zone **$ (2,443,656)**
Net Transmission Joint Zonal Payment for GRE Pricing Zone **$ 1,330,247**

Joint Zonal Revenues and Expenses - 2023 Budget Year

Revenue

NSP JPZ	GRE	SMMPA	MRES	Total
Jan-23	$ 3,355,569	$ 549,911	$ 511,086	$ 4,416,566
Feb-23	$ 3,025,476	$ 540,062	$ 471,943	$ 4,037,481
Mar-23	$ 3,035,751	$ 527,918	$ 486,216	$ 4,049,885
Apr-23	$ 2,651,378	$ 490,181	$ 446,491	$ 3,588,051
May-23	$ 3,467,664	$ 594,979	$ 487,673	$ 4,550,316
Jun-23	$ 4,082,042	$ 720,957	$ 544,144	$ 5,347,143
Jul-23	$ 4,244,383	$ 824,734	$ 587,786	$ 5,656,902
Aug-23	$ 4,283,957	$ 762,974	$ 572,632	$ 5,619,564
Sep-23	$ 3,690,433	$ 651,864	$ 520,103	$ 4,862,401
Oct-23	$ 2,868,495	$ 572,598	$ 485,867	$ 3,926,961
Nov-23	$ 3,109,064	$ 518,470	$ 477,865	$ 4,105,400
Dec-23	$ 3,397,372	$ 557,139	$ 507,516	$ 4,462,028
Total	**$ 41,211,585**	**$ 7,311,788**	**$ 6,099,322**	**$ 54,622,695**

GRE JPZ	GRE
Jan-23	$ 471,273
Feb-23	$ 473,984
Mar-23	$ 417,625
Apr-23	$ 371,209
May-23	$ 416,432
Jun-23	$ 554,899
Jul-23	$ 584,916
Aug-23	$ 552,718
Sep-23	$ 470,531
Oct-23	$ 380,809
Nov-23	$ 422,599
Dec-23	$ 457,981
Total	**$ 5,574,978**

Total GRE Revenue $ 46,786,562.84

Total Transmission Joint Zonal Revenue **$60,197,673**

Expense

NSP JPZ	GRE	SMMPA	CMMPA	NWEC	MMPA	MRES	RPU	Total
Jan-23	$ 2,759,848	$ 1,093,576	$ 115,667	$ 43,033	$ 91,536	$ 121,854	$ 143,969	$ 4,369,483
Feb-23	$ 2,421,754	$ 959,607	$ 101,498	$ 37,762	$ 80,322	$ 106,926	$ 126,332	$ 3,834,201
Mar-23	$ 2,374,151	$ 940,745	$ 99,502	$ 37,019	$ 78,743	$ 104,825	$ 123,849	$ 3,758,835
Apr-23	$ 2,142,560	$ 848,979	$ 89,796	$ 33,408	$ 71,062	$ 94,599	$ 111,768	$ 3,392,173
May-23	$ 2,807,776	$ 1,112,567	$ 117,676	$ 43,781	$ 93,125	$ 123,970	$ 146,469	$ 4,445,365
Jun-23	$ 3,561,548	$ 1,411,245	$ 149,267	$ 55,534	$ 118,126	$ 157,251	$ 185,790	$ 5,638,761
Jul-23	$ 4,113,968	$ 1,630,139	$ 172,420	$ 64,148	$ 136,448	$ 181,642	$ 214,607	$ 6,513,371
Aug-23	$ 3,880,625	$ 1,537,678	$ 162,640	$ 60,509	$ 128,709	$ 171,339	$ 202,435	$ 6,143,934
Sep-23	$ 3,284,164	$ 1,301,333	$ 137,642	$ 51,209	$ 108,926	$ 145,004	$ 171,320	$ 5,199,598
Oct-23	$ 2,546,365	$ 1,008,984	$ 106,720	$ 39,705	$ 84,455	$ 112,428	$ 132,832	$ 4,031,490
Nov-23	$ 2,539,387	$ 1,006,219	$ 106,428	$ 39,596	$ 84,224	$ 112,120	$ 132,468	$ 4,020,442
Dec-23	$ 2,856,400	$ 1,131,834	$ 119,714	$ 44,539	$ 94,738	$ 126,117	$ 149,006	$ 4,522,347
Total	**$ 35,288,547**	**$ 13,982,906**	**$ 1,478,970**	**$ 550,243**	**$ 1,170,414**	**$ 1,558,075**	**$ 1,840,845**	**$ 55,870,000**

GRE JPZ	GRE
Jan-23	$ 377,829
Feb-23	$ 320,817
Mar-23	$ 363,147
Apr-23	$ 285,995
May-23	$ 267,107
Jun-23	$ 387,658
Jul-23	$ 434,129
Aug-23	$ 422,476
Sep-23	$ 311,847
Oct-23	$ 329,896
Nov-23	$ 334,640
Dec-23	$ 373,093
Total	**$ 4,208,633**

Total GRE Expense $ 39,497,179.57

Total Transmission Joint Zonal Expense **$ 60,078,632**

Net Transmission Joint Zonal **$119,040**

Net Transmission Joint Zonal Payment for NSP Pricing Zone **$ (1,247,304)**
Net Transmission Joint Zonal Payment for GRE Pricing Zone **$ 1,366,345**

Joint Zonal Revenues and Expenses - 2024 Budget Year

Revenue

NSP JPZ	GRE	SMMPA	MRES	Total
Jan-24	$ 3,442,053	$ 564,084	$ 524,259	$ 4,530,396
Feb-24	$ 3,214,291	$ 573,766	$ 501,396	$ 4,289,453
Mar-24	$ 3,113,993	$ 541,525	$ 498,748	$ 4,154,265
Apr-24	$ 2,719,714	$ 502,815	$ 457,999	$ 3,680,527
May-24	$ 3,557,038	$ 610,314	$ 500,242	$ 4,667,593
Jun-24	$ 4,187,251	$ 739,538	$ 558,168	$ 5,484,957
Jul-24	$ 4,353,775	$ 845,990	$ 602,935	$ 5,802,700
Aug-24	$ 4,394,370	$ 782,639	$ 587,391	$ 5,764,399
Sep-24	$ 3,785,549	$ 668,665	$ 533,508	$ 4,987,722
Oct-24	$ 2,942,426	$ 587,356	$ 498,390	$ 4,028,172
Nov-24	$ 3,189,196	$ 531,833	$ 490,181	$ 4,211,210
Dec-24	$ 3,484,934	$ 571,499	$ 520,597	$ 4,577,030
Total	**$ 42,384,588**	**$ 7,520,023**	**$ 6,273,812**	**$ 56,178,423**

GRE JPZ	GRE
Jan-24	$ 485,094
Feb-24	$ 487,887
Mar-24	$ 429,837
Apr-24	$ 382,028
May-24	$ 428,608
Jun-24	$ 571,229
Jul-24	$ 602,146
Aug-24	$ 568,982
Sep-24	$ 484,329
Oct-24	$ 391,916
Nov-24	$ 434,959
Dec-24	$ 471,403
Total	**$ 5,738,417**

Total GRE Revenue $ 48,123,005.30

Total Transmission Joint Zonal Revenue $ 61,916,840

Expense

NSP JPZ	GRE	SMMPA	CMMPA	NWEC	MMPA	MRES	RPU	Total
Jan-24	$ 2,834,906	$ 1,090,591	$ 115,353	$ 42,915	$ 91,265	$ 121,524	$ 143,577	$ 4,440,131
Feb-24	$ 2,576,460	$ 991,167	$ 104,836	$ 39,003	$ 82,945	$ 110,445	$ 130,488	$ 4,035,344
Mar-24	$ 2,438,719	$ 938,178	$ 99,232	$ 36,918	$ 78,511	$ 104,540	$ 123,512	$ 3,819,609
Apr-24	$ 2,200,830	$ 846,662	$ 89,552	$ 33,317	$ 70,852	$ 94,343	$ 111,464	$ 3,447,019
May-24	$ 2,884,138	$ 1,109,531	$ 117,356	$ 43,661	$ 92,850	$ 123,634	$ 146,071	$ 4,517,240
Jun-24	$ 3,658,409	$ 1,407,394	$ 148,861	$ 55,382	$ 117,777	$ 156,825	$ 185,285	$ 5,729,931
Jul-24	$ 4,225,853	$ 1,625,690	$ 171,950	$ 63,972	$ 136,045	$ 181,149	$ 214,023	$ 6,618,683
Aug-24	$ 3,986,163	$ 1,533,481	$ 162,197	$ 60,343	$ 128,328	$ 170,874	$ 201,884	$ 6,243,272
Sep-24	$ 3,373,482	$ 1,297,782	$ 137,267	$ 51,068	$ 108,604	$ 144,611	$ 170,854	$ 5,283,668
Oct-24	$ 2,615,617	$ 1,006,231	$ 106,430	$ 39,596	$ 84,206	$ 112,123	$ 132,471	$ 4,096,673
Nov-24	$ 2,608,449	$ 1,003,473	$ 106,138	$ 39,487	$ 83,975	$ 111,816	$ 132,108	$ 4,085,447
Dec-24	$ 2,934,084	$ 1,128,745	$ 119,388	$ 44,417	$ 94,458	$ 125,775	$ 148,600	$ 4,595,467
Total	**$ 36,337,109**	**$ 13,978,922**	**$ 1,478,561**	**$ 550,079**	**$ 1,169,816**	**$ 1,557,658**	**$ 1,840,337**	**$ 56,912,483**

GRE JPZ	GRE
Jan-24	$ 389,164
Feb-24	$ 330,441
Mar-24	$ 374,042
Apr-24	$ 294,574
May-24	$ 275,120
Jun-24	$ 399,287
Jul-24	$ 447,153
Aug-24	$ 435,150
Sep-24	$ 321,203
Oct-24	$ 339,793
Nov-24	$ 344,679
Dec-24	$ 384,285
Total	**$ 4,334,892**

Total GRE Expense $ 40,672,000.77

Total Transmission Joint Zonal Expense $ 61,247,375

Net Transmission Joint Zonal **$669,466**

Net Transmission Joint Zonal Payment for NSP Pricing Zone **$ 56,178,423**
Net Transmission Joint Zonal Payment for GRE Pricing Zone **$ 1,403,526**