Direct Testimony and Schedules
Kelly A. Bloch

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-20-723
Exhibit___(KAB-1)

Distribution

November 2, 2020

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Kelly A. Bloch. I am the Regional Vice President, Distribution Operations for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company, a Minnesota corporation (NSPM) and an operating company of Xcel Energy Inc. (Xcel Energy).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over 29 years of experience in the utility industry. I joined Public Service Company of Colorado, another operating company of Xcel Energy, in 1991 and have served in various engineering roles since that time. In my current role, I am responsible for the electric and natural gas distribution design and construction activities for the Company's service areas in the states of Minnesota, North Dakota, South Dakota, Michigan, and Wisconsin. My resume is attached as Exhibit___(KAB-1), Schedule 1.

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

A. I present and support the Company's capital and operations and maintenance (O&M) budgets for the Distribution business area, for purposes of determining electric revenue requirements and final rates in this proceeding. I further discuss the assumptions used in the Company's Minimum System Study and Zero Intercept Analysis, provide information regarding the cost savings achieved from the LED street light conversion project, and discuss methods to measure losses on the distribution system. I also address the Company's Electric Vehicle (EV) programs and the EV capital and O&M expenses that are included in Distribution's budget.

Q. PLEASE PROVIDE AN OVERVIEW OF THE DISTRIBUTION BUSINESS AREA.

A. The Distribution organization is responsible for operating, maintaining, and constructing the distribution system that is the critical final link in delivering electricity to our customers to power their homes and businesses. Given this responsibility, many of Distribution's investments and efforts are focused on maintaining the reliability, resiliency, and health of our existing distribution facilities.

Q. PLEASE PROVIDE AN OVERVIEW OF THE WORK THAT DISTRIBUTION WILL BE PERFORMING OVER THE TERM OF THIS MULTI-YEAR RATE PLAN (MYRP) (2021-2023)?

A. In recent years, the utility industry has changed as have customers' expectations for power availability and reliability. Customers are more reliant than ever on electricity to power computers, charge phones, and charge their EVs. Thus customers expect quality, uninterrupted power – and their expectations continue to evolve and increase. However, our distribution system is aging as many components were put in place in the 1950s and 1960s with a 50-year life expectancy, and were not originally designed to meet the demands of a modern grid or today's more frequent severe weather events. Further, unlike the transmission system, the distribution system is not fully redundant –so individual system component failures can directly impact a customers' reliability.

At the same time, the way that our customers use our distribution system has also changed. The distribution system is moving from one-way power flows to two-way power flows as customers are installing distributed generating resources (rooftop solar) on their homes and businesses. Accommodating these distributed resources requires that our distribution equipment be robust enough to maintain proper voltage levels when these new resources come online. In addition, these distributed resources will result in greater wear on our already aging facilities.

It is with this backdrop that Distribution must make the necessary investments as part of this MYRP to meet our customers' reliability expectations and to prepare our system to meet the requirements of a modern grid. To that end, throughout the term of this MYRP, we will be increasing investments in our established asset health and reliability programs that focus on replacing core components of the distribution system such as underground cables, poles, and substation transformers. We will also be furthering these objectives by adding new programs to bolster the resiliency of our system.

We also maintain reliable service for our customers by investing in capacity projects to support growing load from existing and new customers. During the term of this multi-year rate plan, we will be completing several large capacity projects to ensure that our substations have the ability to accommodate recent load growth. For instance, we will be adding a new transformer and several miles of new feeders at the Elm Creek Substation in Maple Grove to accommodate recent load growth in that area.

During the term of the multi-year rate plan, the Company will take the next steps in the Company's Advanced Grid Intelligence and Security (AGIS) initiative through the deployment of AMI meters and FAN across our entire service territory. The Commission previously certified AMI and FAN as part of the Company's 2019 Integrated Distribution Plan (IDP) filing.[1] While the Company will seek rate recovery for the bulk of the AMI and FAN investments through the Transmission Cost Recovery (TCR) Rider[2] rather than in this case, these investments represent an important part of the work that Distribution will complete during the term of this rate plan.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. My testimony first describes the workings of the Distribution organization and the services that we provide to our customers. I will identify the key categories of capital investments undertaken by Distribution and describe how the Distribution business area prepares and manages its capital budget. I explain that we are proposing capital additions of approximately $334.9 million for 2021, $424.2 million for 2022, and $453.7 million for 2023 on a State of Minnesota Electric Jurisdiction basis. I provide information on the key capital projects that Distribution will complete over the term of the MYRP organized by our capital budget categories.

I then discuss Distribution's O&M budgets for 2021 to 2023, which are driven by internal and contract labor costs, vegetation management, damage prevention, AGIS, fleet, and materials. I also explain why our O&M budgets are reasonable and reflect expenditures that are needed to ensure that our distribution system is safe and reliable.

[1] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, AND CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS, Docket No. E002/M-19-666 (June 23, 2020).

[2] The business case for the AGIS Initiative, including a comprehensive assessment of qualitative and quantitative benefits to customers, was provided in the Company's 2019 Integrated Distribution Plan (IDP) filing. The Company plans to address Commission requirements related to cost recovery for the AGIS initiative as part of a future TCR Rider filing.

In addition, I address the Company's EV programs, and discuss the EV capital and O&M expenses included under the Distribution budget for 2021 to 2023. Xcel Energy has committed to powering 1.5 million EVs across the areas served by Xcel Energy's operating companies by 2030, which is 20 percent of all vehicles and is equivalent to a 30-fold increase in electric vehicles. This increase in EVs will both save customers fuel costs but it will also significantly reduce carbon emissions. To facilitate this increased EV adoption, the Company is investing in several Commission-approved EV pilots and programs and has budgeted for additional pilots and programs that will be brought forth for Commission approval during the term of this multi-year rate plan.

Further, I provide information regarding the cost and cost savings related to the Light Emitting Diode (LED) street light conversion project. I then provide information supporting the assumptions used in the Company's Minimum System Study and Zero Intercept Analysis. Finally, I report on methods to determine electric losses on the distribution system as required by the Commission's order from our 2015 rate case (Docket No. E002/GR-15-826).

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. My testimony is organized into the following sections:

- *Section I* – Introduction
- *Section II* – Distribution Overview
- *Section III* – Capital Investments
- *Section IV* – O&M Budget
- *Section VI* – Electric Vehicle Programs
- *Section VII* – LED Street Lights

- *Section VIII* – Minimum System Study and Zero Intercept Analysis
- *Section IX* – Distribution System Losses
- *Section X* – Conclusion

II. DISTRIBUTION OVERVIEW

Q. PLEASE PROVIDE AN OVERVIEW OF NSPM'S DISTRIBUTION SYSTEM.

A. The NSPM distribution system serves approximately 1.5 million electric customers across the NSPM territory, including approximately 1.3 million customers in Minnesota. The distribution system is the final link that allows electricity to safely and reliably reach our customers' homes and businesses. The NSPM distribution system is comprised of approximately 1,200 feeders, approximately 15,000 circuit miles of overhead conductor on over 500,000 overhead poles and over 11,000 circuit miles of underground cable. This network of feeders connects over 26,000 miles of distribution lines and 240 distribution-level substations in Minnesota.

Q. WHY IS THE DISTRIBUTION BUSINESS UNIT IMPORTANT TO THE COMPANY AND ITS CUSTOMERS?

A. The Distribution business unit is responsible for constructing, operating, maintaining, and repairing the portion of the electric system that directly connects to our customers' homes and businesses. The work performed by Distribution is essential to ensuring that the electric service our customers receive is safe, reliable, and affordable. Our work includes performing regular maintenance, repairs, and replacement of poles, wires, underground cables, metering, and transformers, extending service to new customers or increasing the capacity of the system to accommodate new or increased load, and repairing facilities damaged during severe weather to quickly restore service to customers.

Q. PLEASE DESCRIBE THE DISTRIBUTION BUSINESS UNIT'S KEY FUNCTIONS AND SERVICES.

A. The key functions of the Distribution organization include operating the distribution system, restoring service to customers after outages, performing routine maintenance, constructing new infrastructure to serve new customers, and making upgrades necessary to improve the performance and reliability of the distribution system. There are approximately 1,300 employees (including XES employees) assigned to provide services to the NSPM distribution system. These employees are assigned to one of the five functional areas within Distribution: Distribution Operations, Engineering, Business Operations, AGIS and Metering, and Planning and Performance.

Q. WHAT ARE THE RESPONSIBILITIES OF THESE FOUR FUNCTIONAL AREAS OF DISTRIBUTION?

A. The key responsibilities of these four functional areas include:

- *Operations*. Responsible for the design, construction, and maintenance of the distribution system, as well as monitoring and operating the system from the Electric Control Center, responding to electric distribution trouble calls, and coordinating emergency response.
- *Engineering*. Provides technical support and system planning, including addressing distribution-related customer service issues.
- *Business Operations*. Responsible for several areas, including vegetation management, outdoor lighting, facility attachments, and the builders call-line.

- *AGIS and Metering.* Responsible for implementing the AGIS initiative and metering.
- *Planning and Performance.* Provides business planning, consulting, analytical services and performance governance and management.

Q. HOW DOES DISTRIBUTION SUPPORT THE FUNCTIONS DESCRIBED ABOVE?

A. Distribution makes capital investments and incurs O&M costs to maintain and improve the reliability of the system, modernize the distribution system, improve functionality, extend service to new customers, and relocate facilities in response to road construction or other governmental projects. I will discuss our capital investments and O&M trends in more detail below.

III. CAPITAL INVESTMENTS

A. Overview of Distribution's Capital Investments

Q. HOW DOES DISTRIBUTION CATEGORIZE THEIR CAPITAL ADDITIONS?

A. Our capital projects fall into eight capital budget groupings, depending on the primary purpose of the project. Distribution has a well-defined process for identifying and determining our investments within these eight capital budget groupings. These groupings are:

<u>Asset Health and Reliability</u>: Projects in this category are related to replacing infrastructure that is experiencing high failure rates and, as a result, negatively impacting service reliability and increasing O&M expenditures needed to repair the equipment. When poor performing assets are identified, projects that will improve asset performance are included in the budget. Projects in this category include replacement of underground cable, wood poles, overhead lines,

substation equipment, transformers, and switchgear that have reached the end of their lives. This category also captures replacements due to storms and public damage.

<u>New Business</u>: This work includes new overhead and underground extensions and services associated with extending service to new customers. Capital projects required to provide service to new customers include the installation or expansion of feeders, primary and secondary extensions, and service laterals that bring electrical service from an existing distribution line to a new home or business.

<u>Capacity</u>: This category includes capital investments associated with upgrading or increasing distribution system capacity to handle load growth on the system and to serve load when other elements of the distribution system are out of service. This includes installing new or upgraded substation transformers and distribution feeders. Capacity projects generally span multiple years and are necessitated by increased load from either existing or new customers.

<u>Mandates</u>: This category covers projects to relocate utility infrastructure in public rights-of-way when mandated to do so to accommodate public works projects such as a road widening or realignment project. These projects generally trend with the availability of municipal and state funding for public works projects. Mandate projects typically result in updated distribution infrastructure.

Tools and Equipment: This category includes tools, equipment, communication equipment, and locate costs associated with modifications or additions to the distribution system or supporting assets.

Electric Vehicle Programs: This category includes the capital costs associated with EV pilots and programs that were previously approved by the Commission – the Residential EV Service Pilot, the Fleet EV Service Pilot, the Public Charging Infrastructure Pilot, the Residential EV Subscription Service Pilot, and the EV Home Service program. Additionally, the Company has budgeted for three new EV programs that were discussed in our 2020 Transportation Electrification Plan – a Multi-Unit Dwelling Charging Offering,[3] an Electric School Bus Offering, and a Customer-provided Managed Charging Offering. The EV program is discussed in more detail in Section V below.

Solar: This category includes the distribution costs associated with interconnecting solar gardens to the distribution system as well as providing service extension to allow electric service for any auxiliary electric needs. The costs for these facilities are billed to the developer at several different increments throughout the development and construction of the solar garden. Once payment is received and the work is completed by Distribution, a credit is applied to this category.

AGIS: Traditionally, our investments to modernize our system were budgeted in the Asset Health category. Beginning in 2019 as we launched the AGIS initiative, we separated these investments into their own budget category of

[3] The Company filed its request for approval of a Multi-Dwelling Unit EV Service Pilot on September 10, 2020, in Docket No. E002/M-20-711.

AGIS. The AGIS initiative will improve power reliability, reduce power outages, integrate increasing amounts of distributed energy resources (DER) onto the grid, and empower customers to control and track their energy usage. As I mentioned, the Company will be seeking recovery of most of the capital costs associated with the AGIS initiative in the TCR. These investments are discussed here as they are an important part of our overall capital investments during the term of this MYRP.

Q. ARE FLEET CAPITAL INVESTMENTS INCLUDED IN THESE GROUPINGS?

A. No. Fleet capital, which is associated with the necessary replacement of vehicles and equipment that have reached their end of life, is addressed in the Direct Testimony of Company witness Mr. William K. Husen for all of the Company's business units.

B. Distribution Capital Budget Development and Management

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

A. In this section, I will provide an overview of Distribution's capital budgeting process, project development, and budget management processes. I note that I will describe the EV investments in detail separately in Section V.

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

A. The Distribution business area employs a "bottoms up" approach to budgeting and planning for the future needs of the distribution system. In coordination with the corporate budget process, the Distribution business area budgets for our work by identifying the necessary investments we need to make to the distribution system over the next five years. We identify specific projects and forecast appropriate funding for our routine investments. We utilize a comprehensive capital forecasting system to budget for and track these costs.

Distribution's annual capital budget is also dependent on the Company's overall finances and other business area needs. Company witness Ms. Melissa L. Ostrom explains how the Company establishes overall business area capital spending guidelines and budgets based on financing availability, specific needs of business areas, and overall needs of the Company.

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

A. We begin our budgeting process in October by reviewing the recent summer peak loads to identify new or increased risks. In addition, our capital budget is dependent on the state of the economy, which has a significant impact on the development of new and expanded business, conditions that drive new housing, large commercial load increases, and road work projects that affect distribution facilities. To obtain an accurate gauge of this work, our budgeting process begins with economic forecasting and analysis of historical spending trends to assess likely new business needs, required replacement of assets, and relocation of distribution facilities to accommodate road construction. We also assess the impacts of system growth on our capacity needs, including the risk of overloads and the system's ability to handle single contingency events.

Although economic factors drive much of our budget, we also must ensure that the existing system remains reliable. This includes proactively replacing assets near the end of their lives as well as budgeting for replacement of facilities due to unanticipated failure or damage such as those facilities damaged during storms. To budget for proactive replacements, we evaluate the age and condition of facilities and determine the amount of replacement or refurbishments that are needed in a particular year. To budget for unanticipated failures, we forecast the likely costs of replacing assets that will fail or be damaged based on historical trends. This analysis results in identification of capital projects that are needed for routine work necessary to maintain our existing system and the work required to support new customers or new construction.

Q. HOW DOES DISTRIBUTION ACCOUNT FOR ROUTINE WORK THAT MUST BE PERFORMED EACH YEAR?

A. The nature of the distribution system is that we must account for those regular, common capital additions needed to support new business growth, system reinforcements, or rebuilds. This routine work can also include material upgrades to the distribution network, such as reconductoring a line, upgrading a distribution transformer, or replacing a substation regulator. The two largest categories of routine capital additions are cable replacements and transformer purchases.

As I will discuss, our budgeting process provides us with the flexibility to efficiently allocate funds for performing core business functions, such as connecting new customers, reconstruction of facilities, street light expenditures, purchasing new meters, and transformers. These routine work order accounts generally include the following capital budget categories: Asset Health and Reliability, New Business, Capacity, Mandates, Tools and Equipment, and AGIS investments.

Q. HOW DOES DISTRIBUTION DEVELOP A BUDGET FOR ROUTINE WORK ORDERS?

A. For routine work orders that address asset health issues or relocations, we use averages of historical values escalated by the corporate inflation rate (around two percent per year) to determine expected levels of spend. This total expected routine work order budget is then allocated to each service area using the average historical ratio of the past five years. The allocation is adjusted to ensure unique, one-time projects in a service area do not impact the calculation of the average five-year historical expenditures.

The budget for routine work orders for new service extensions is developed using a cost-per-meter methodology. This process relies on the forecast for the number of new meter sets for each local operating area. Inputs and assumptions are also developed that reflect inflation factors used in determining the assumed increase or decrease in the components that comprise the new service costs. These factors (labor, non-labor, contractor, material, equipment, bargaining labor increases and corporate overhead rates) reflect both corporate and operating company rates. Historical data is used to determine the major drivers or components that make up new business costs. The components are: labor (both Company and contracted), labor loadings, material (excluding meters and transformers), equipment, transportation, overheads, and other costs.

Using these components, we then develop a cost-per-meter for each local operating area. This provides us with the ability to apply the related inflation factors to the specific components that make up the overall cost-per-meter. The Distribution business unit also uses this data for variance analysis against what actually occurred during the year. The variance analysis allows us to determine which components account for the difference in the forecast versus actual expenditures.

After the preliminary forecasts estimating our new service needs have been determined, the data is reviewed with our management to determine if there will be substantial changes in the operations (e.g., crew mix, major projects, and labor issues). Depending on the outcome of these reviews, adjustments are made to the preliminary forecast and the proposed routine work order budgets are then submitted for final approval.

Q. HOW ACCURATE IS THIS BUDGETING PROCESS FOR ROUTINE PROJECTS?

A. The budget process that we utilize has generally proven to be an accurate gauge of the routine work that will be performed each year. However, as discussed above, sometimes there are storms or New Business fluctuations that can lead to unexpected increases in our routine work. When these circumstances arise, we seek to actively control our expenditures to stay as close to budget as reasonably practicable by prioritizing our work and allocating funds accordingly.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THIS BUDGET REPRIORITIZATION WORKS?

A. If we have a significant increase in Mandates (relocations) in a given year, this may cause us to have to decrease funding in other areas. Our work on these required relocations – even when we have been given very short notice – cannot be deferred. To maintain investment levels we must defer controllable projects which can reasonably be reduced upon short notice. Asset Health and Reliability projects such as cable replacements fit this criterion and may receive less funding in a given year due to the need to increase funding related to mandated relocations.

Q. WHAT HAPPENS WHEN CABLE REPLACEMENT WORK IS DEFERRED?

A. We have developed and employ criteria to ensure we prioritize cable replacement to most effectively and efficiently improve our customer reliability experience. Specifically, we prioritize our cable replacements by those that are most likely to fail again and would impact the largest number of customers when they do fail. When funding is reduced, we reexamine and reprioritize replacements to ensure we focus on the most effective replacements and defer until the following year those cables that are least likely to imminently sustain a subsequent failure.

Q. HOW DOES THE DISTRIBUTION BUSINESS AREA ESTABLISH BUDGETS FOR NON-ROUTINE PROJECTS?

A. In addition to our routine work orders, the Distribution business area also budgets for and implements certain discrete projects that are identified to address a particular need that does not reoccur each year. At a high level, the identification and assessment of problems or "risks" along with their related solutions or "mitigations" is integral to identifying larger projects we must fund in addition to the work I describe above.

Risks are issues that can result in negative consequences to the Company's ability to provide safe and reliable service. Mitigations are solutions that address the risks. To help ensure that each risk is being addressed by the most efficient solution, we assess all mitigation alternatives and select the one that provides the best value to our customers and our Company.

Q. HOW ARE INDIVIDUAL RISKS AND MITIGATIONS IDENTIFIED AND DEVELOPED?

A. As capital spending is determined and throughout the year as new issues are identified, each operating area and supporting engineer brings risks (problems) and mitigations (solutions) forward based on their knowledge of the assets and operations within their territory. The operating areas' focus is on building, operating, and maintaining physical assets while achieving quality improvements and cost efficiencies. All the risks and mitigations are submitted as project requests and entered into RiskRegister, a software tool developed by the Company and used to track and rank projects based on the inputs provided. Individual project requests must include specific information regarding their annual costs and benefits.

Budgeting personnel focus on the health and age of our existing assets, standardization, and mitigation of risk, and provide coordination and consistency in evaluating individual project requests with the Distribution organization. Engineering and operations personnel then work with budgeting personnel around each risk to evaluate and score each mitigation individually before ranking the projects. The factors that are used to score the identified risks and proposed mitigations are as follows:

- *Reliability* – Identification of overloaded facilities, potential for customer outages, annual hours at risk, and age of facilities;
- *Safety* – Identification of yearly incident rate before and after the risk is mitigated;
- *Environmental* – Evaluation of compliance with environmental regulations. To the extent this factor applies to the project being evaluated, it is prioritized, however this factor is not usually applicable;

- *Legal* – Evaluation of compliance before and after the risk is mitigated; and
- *Financial* – Identification of the gross cash flow, such as incremental revenue, realized salvage value, incremental recurring costs, etc., and identification of avoided costs such as quality of service pay-outs and failure repairs.

An analysis of these factors results in a proposed project list that is ranked.

Q. AFTER INDIVIDUAL PROJECTS ARE RANKED, HOW DOES DISTRIBUTION DETERMINE WHICH PROJECTS TO FUND?

A. Funding for projects is not unlimited, and typically the cost for identified individual projects exceeds available funding. In addition, the volume and diverse types of risks require utilization of a systematic process to perform specific risk assessment of the asset's overall future performance expectations. Therefore, it is important to rank or prioritize proposed individual projects before authorizing a project to move forward. This is accomplished by ranking the assessment of each project against each other. Highest priority is given to projects that Distribution must complete within a given budget year to ensure that we meet regulatory and environmental compliance obligations and to connect new customers.

Q. HOW ARE AUTHORIZED FUNDING GUIDELINES DETERMINED AND APPLIED?

A. The capital expenditure guidelines are determined at the corporate level for Distribution as explained by Ms. Ostrom. Capital expenditures associated with non-discretionary projects are included in the budget first, and then any authorized spending is targeted at discretionary projects based on their ranking.

By including both routine work orders as well as specific projects in our capital budget, we are able to meet the immediate needs of our customers while also proactively addressing system needs as budgeted funds allow. Further, this process provides for flexibility in reallocating our capital budget to address changing system needs and system emergencies.

Q. PLEASE DESCRIBE THE CAPITAL EXPENDITURES BUDGET APPROVAL PROCESS.

A. Capital projects that have been approved for funding are uploaded into our budgeting software. The Operations President's executive management team reviews and approves this list. After the business area has been afforded the opportunity to make adjustments, the capital projects are available for corporate approval. After receiving approval from the Board of Directors, work release plans are finalized and work can be deployed.

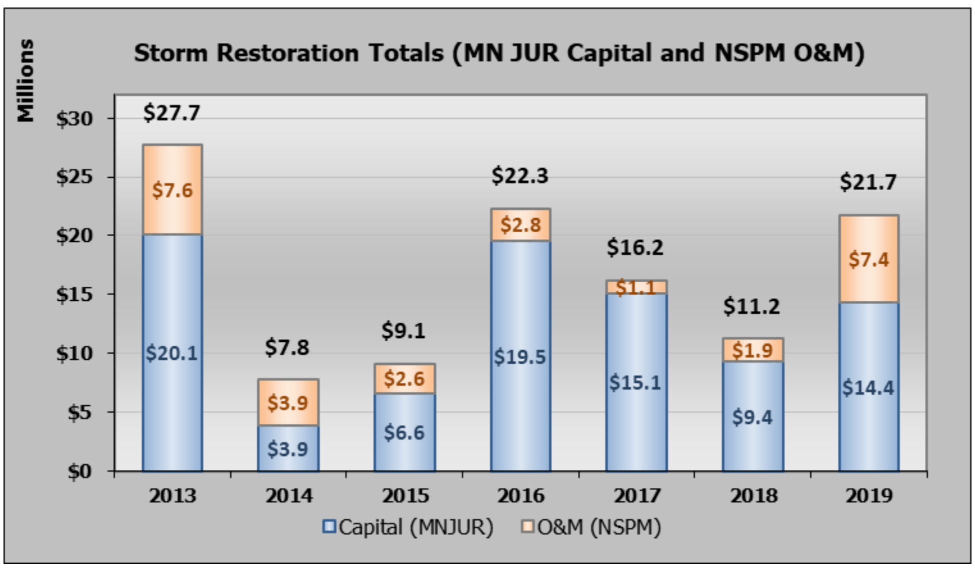
Q. HOW IS THE CAPITAL EXPENDITURE BUDGET IMPLEMENTED AFTER APPROVAL?

A. After the capital expenditures budget is finalized, the approved project list becomes the basis for the release of projects during the calendar year. This process must be somewhat flexible to allow for needed additions and deletions within a given year. For example, should an emergency occur during the year, priorities may change and result in an adjustment to the list of projects. Projects that were previously approved may be delayed to accommodate the emergency. Through our budget deployment process we are therefore able to meet identified needs and requirements, adjust to changing circumstances and prudently ensure the long-term health of the distribution system.

Q. CAN YOU PROVIDE AN EXAMPLE OF AN EMERGENCY THAT COULD IMPACT DISTRIBUTION'S BUDGET?

A. Yes. One of the primary examples is storm restoration. Our annual capital and O&M expenses for storm restoration are dependent on the magnitude and frequency of severe weather in a particular year. The unpredictable nature of severe weather makes precise budgeting difficult as the weather each year is different. The figure below depicts how our capital and O&M storm restoration spend is uneven year to year due to the unpredictable nature of storms.

Figure 1



In certain years, such as 2019, the frequency and severity of severe weather requires us to reallocate portions of our budget from another area to fund increased storm restoration. Xcel Energy's storm response is industry-leading and our ability to reallocate our budgets allows us to promptly restore our customers' electric service as quickly as possible.

C. Distribution's 2017-2019 Capital Investment Trends

Q. FOR 2017-2019, WHAT WERE THE PRIMARY DRIVERS OF DISTRIBUTION'S CAPITAL ADDITIONS?

A. The primary drivers of Distribution's increased capital investments over this period were Mandate and Capacity projects. The strong economy during these years lead to a significant uptick in road construction projects that required the Company to relocate its existing facilities. Specifically, Distribution performed an increasing number of Mandate projects to accommodate road construction projects by the City of Minneapolis on 8th Street in downtown Minneapolis and due to the Southwest Light Rail project between Minneapolis and Eden Prairie. We also saw a similar upward trend of road construction projects in other cities, but these road construction projects were not as extensive as the two projects I noted.

In 2017, our capital additions in Capacity projects increased due to the need to add capacity at substations to accommodate load growth on certain portions of our system. For instance, in 2017 we completed the following large capacity projects: Baytown Substation project ($6.9 million) and Lake Bavaria Substation project ($8.4 million). These projects involved adding feeder lines, adding additional transformers, and, in the case of Lake Bavaria, constructing a new substation to support increased load from existing and new customers.

Q. WHAT WERE THE CAPITAL INVESTMENT TRENDS FOR 2017-2019 IN THE ASSET HEALTH AND RELIABILITY CATEGORY?

A. During this period, Distribution had relatively steady and consistent expenditures in its Asset Health and Reliability category, which is Distribution's largest capital budget category. Capital additions in this category did, however, slightly increase in 2019 due to a greater number of pole replacements. This was to address a backlog of pole replacements as well as due to a higher than average "rejection" rate (i.e., the proportion of poles that fail testing and need to be replaced) for poles inspected in 2018 and 2019.

Distribution conducts annual pole inspections for pole rot and other defects. Pole rot at the base of the pole can be a cause of pole failure, especially in severe weather. Based on these inspections, we identify poles for either replacement, repair, or monitoring. Due to the overall age of the poles on our system, as well as fine tuning of the inspection process and criteria, the number of poles that have been identified for replacement has increased steadily since 2012. For instance, in 2018 and 2019 the rejection rate was approximately 13 percent of the inspected poles whereas the average historical rejection rate has been approximately nine percent. This higher than average rejection rate coupled with a need to address a backlog pole replacements resulted in increased spending on pole replacements in 2019 as compared to 2018.

Also in 2019, we completed our LED street light conversion project that resulted in an increase in capital additions in the Asset Health and Reliability category for that year.

Q. WERE THERE OTHER DRIVERS OF DISTRIBUTION'S CAPITAL ADDITIONS DURING THIS PERIOD?

A. Yes. We also saw a slight bump in capital additions in New Business in 2018 due to the favorable economy that lead to an increase in new service extensions for new residential and commercial developments.

Another driver of Distribution's 2019 capital additions was the launch of the AGIS initiative. Our AGIS investments in 2019 related to the implementation of the Advanced Distribution Management System (ADMS) and a limited deployment of Advanced Metering Infrastructure (AMI) and the Field Area Network (FAN) in support of the Time of Use (TOU) pilot. I note that the costs for these projects were approved for inclusion in the TCR Rider.[4]

Q. PLEASE PROVIDE A BREAKDOWN OF THE COMPANY'S CAPITAL INVESTMENTS IN THE CAPITAL BUDGET CATEGORIES.

A. Table 1 and Figure 2 provide a breakdown of our capital expenditures by capital budget grouping for 2017 to 2019. Table 2 and Figure 3 below provide a breakdown of our capital additions by capital budget grouping for 2017 to 2019.

[4] *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. E-002/M-17-797, ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS (Sept. 27, 2019); *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket No. E-002/M-19-666, ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, AND CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS (July 23, 2020).

Table 1

2017-2019 Distribution Capital Expenditures

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Expenditures (excludes AFUDC)	2017 Actual	2018 Actual	2019 Actual
Asset Health & Reliability	$94.4	$99.7	$95.3
New Business	$53.8	$62.2	$55.8
Capacity	$13.3	$13.6	$21.6
Mandates	$15.4	$28.9	$39.3
Tools and Equipment	$2.2	$3.0	$4.2
Electric Vehicle Program (EVP)	$0.0	$0.0	$0.6
Solar	$4.8	($11.4)	($0.8)
Advanced Grid Intelligence & Security (AGIS)	$0.0	$0.1	$5.6
Total	**$184.0**	**$196.2**	**$221.7**

Figure 2

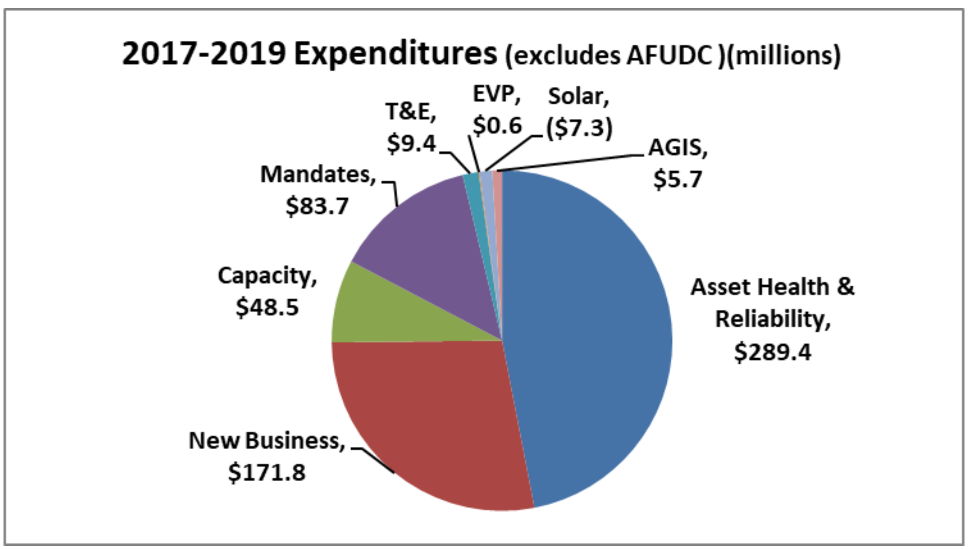


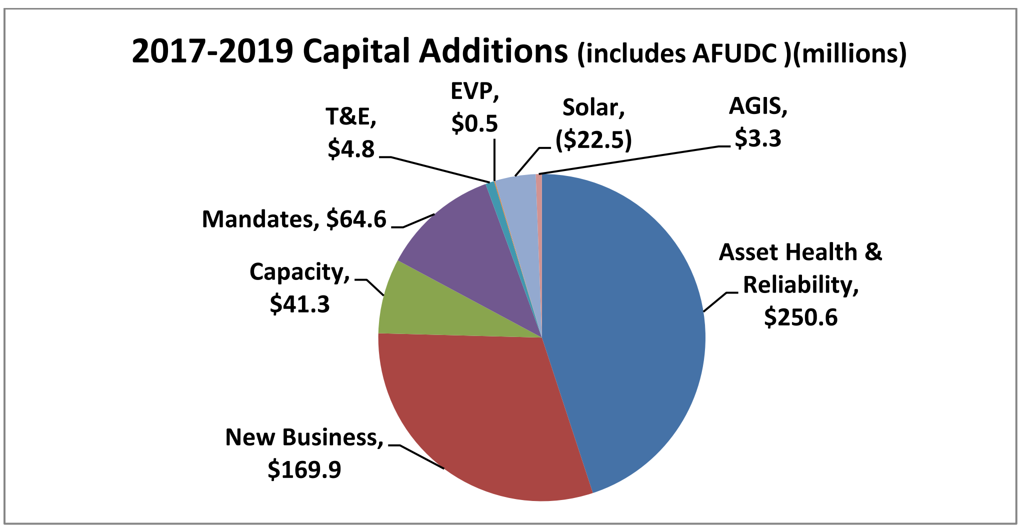
Table 2

2017-2019 Distribution Capital Additions

(Dollars in Millions)[5]

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2017 Actual	2018 Actual	2019 Actual
Asset Health & Reliability	$81.8	$81.6	$87.3
New Business	$50.1	$63.5	$56.3
Capacity	$18.6	$10.4	$12.2
Mandates	$13.8	$21.6	$29.2
Tools and Equipment	($0.5)	$2.8	$2.5
Electric Vehicle Program (EVP)	$0.0	$0.0	$0.5
Solar	($7.2)	($13.2)	($2.1)
Advanced Grid Intelligence & Security (AGIS)	$0.0	$0.0	$3.3
Total	**$156.6**	**$166.8**	**$189.3**

Figure 3



[5] The 2017 Tools and Equipment budget category is negative due to a sales tax credit for certain qualifying materials. Starting in 2018, Distribution applied this credit to the specific budget category associated with the qualifying materials rather than to the Tools and Equipment category.

Q. WHY ARE DISTRIBUTION'S CAPITAL EXPENDITURES FOR 2017-2019 LOWER THAN THE CAPITAL ADDITIONS FOR THESE YEARS?

A. While the capital addition trend is directly affected by our capital expenditures, the capital additions trend may not exactly match the capital expenditure trend. Capital additions may fluctuate more depending on the length of time required to complete individual projects, and because the total includes allowed funds used during construction (AFUDC) for certain projects. The capital expenditure trend reflects the incremental investment in the project, whereas the capital addition trend reflects the total investment that is placed in service at the conclusion of a project.

Q. CAN YOU ADDRESS DISTRIBUTION'S CAPITAL INVESTMENTS IN 2020 SO FAR?

A. Our capital investments for 2020 are trending higher than recent historical actuals due primarily to increasing investments in the Asset Health and Reliability, Capacity, and Tool and Equipment categories.

Asset Health and Reliability trended upward, driven largely by an increased investments in pole replacements. The Company conducts pole inspections each year with a goal to inspect each pole on a 12-year inspection cycle. Due to the overall age of the poles on our system, fine tuning of the inspection process and criteria in recent years, and the need to address a backlog of pole replacements identified in prior years, we replaced a greater number of poles in 2020 as compared to 2017-2019. Specifically, in 2020 we are forecasting that we will replace over 4,000 poles throughout the NSPM service territory as compared to approximately 1,700 poles in 2019.

Our Capacity additions are also increasing in 2020 due to several large Capacity projects such as the Raptor Substation Project, a new substation that is being constructed to serve growing load in Woodbury. A portion of the Raptor Substation Project went into service in 2020, but the remaining portion of the project will be completed in 2021. Other large Capacity projects that will be completed in 2020 include the reinforcing a transformer at the St. Cloud Substation ($4.4 million), installation of a new Jamaica Substation ($3.5 million), and installing an additional transformer and associated feeders at the Rosemount Substation ($3.9 million). Our Capacity projects are also driving our increase in the Tools and Equipment category as these substation projects require new communication equipment to be installed to ensure the Company is able to obtain load and other system data from these new substation assets.

In 2020, Distribution also made investments in our Commission-approved EV pilots and programs. While these EV programs and pilots are discussed in greater detail in Section V, one of the programs that we worked on in 2020 was our Fleet Charging Pilot that was launched in 2019 to build out the EV charging infrastructure for light-duty vehicles and buses in Minnesota.

Finally, our 2020 capital additions reflect continued work on the AGIS initiative.

Distribution's capital expenditures and capital additions forecast for 2020 and actuals for 2017 to 2019 are provided in Tables 3 and 4.

Table 3

2017-2020 Distribution Capital Expenditures

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Expenditures (excludes AFUDC)	2017 Actual	2018 Actual	2019 Actual	2020 Forecast
Asset Health & Reliability	$94.4	$99.7	$95.3	$106.6
New Business	$53.8	$62.2	$55.8	$60.4
Capacity	$13.3	$13.6	$21.6	$49.2
Mandates	$15.4	$28.9	$39.3	$31.7
Tools and Equipment	$2.2	$3.0	$4.2	$5.7
Electric Vehicle Program (EVP)	$0.0	$0.0	$0.6	$3.8
Solar	$4.8	($11.4)	($0.8)	($0.1)
Advanced Grid Intelligence & Security (AGIS)	$0.0	$0.1	$5.6	$1.4
Total	**$184.0**	**$196.2**	**$221.7**	**$258.7**

Table 4

2017-2020 Distribution Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2017 Actual	2018 Actual	2019 Actual	2020 Forecast
Asset Health & Reliability	$81.8	$81.6	$87.3	$105.2
New Business	$50.1	$63.5	$56.3	$51.8
Capacity	$18.6	$10.4	$12.2	$35.3
Mandates	$13.8	$21.6	$29.2	$21.9
Tools and Equipment	($0.5)	$2.8	$2.5	$6.8
Electric Vehicle Program (EVP)	$0.0	$0.0	$0.5	$4.0
Solar	($7.2)	($13.2)	($2.1)	$6.8
Advanced Grid Intelligence & Security (AGIS)	$0.0	$0.0	$3.3	$2.4
Total	**$156.6**	**$166.8**	**$189.3**	**$234.1**

D. Overview of Distribution's 2021 to 2023 Capital Investments

Q. PLEASE PROVIDE AN OVERVIEW OF THE KEY DRIVERS OF DISTRIBUTION'S CAPITAL INVESTMENTS OVER THE TERM OF THIS MULTI-YEAR RATE PLAN.

A. The health of our distribution system assets is critical to our ability to ensure that our customers receive safe, reliable, and cost effective electricity. We make investments each year to maintain this vast system of underground cables, overhead feeders and poles, and substation transformers.

While our historical levels of investments have been sufficient to maintain our system in the past, we are currently in the midst of an industry transition where our customers are requiring and expecting more from the distribution system than ever before. Now more than ever, customers expect quality, uninterrupted reliable power. To meet these reliability expectations, we must proactively replace worn, aging, and damaged assets since our distribution system does not have the same redundancy that exists in our transmission system and the failure of any one component can directly impact customers and lead to an outage.

At the same time, customers are installing distributed energy resources (such as rooftop solar) at their homes and businesses which requires our system to operate in new ways to accommodate this two-way flow of electricity. Our customers are also more reliant than ever before on electricity not just for their basic day to day activities, but also for charging their EVs. This increase in EV adoption will stretch and, in many cases, exceed the capability of older distribution secondary lines with smaller sized conductors and transformers potentially causing capacity or voltage constraints.

As a result, we have been forecasting for several years the need for greater investments in our distribution system both in our established Asset Health and Reliability programs and in new programs targeted at addressing the more vulnerable parts of our system. In our 2019 IDP filing, we presented the Incremental System Investment (ISI) initiative as our plan to improve reliability on those elements of the system that are the closest to our customers as well as provide the infrastructure to support increased customer choice and the adoption distributed energy resources and EVs.[6]

As part of this rate case, we have refined the scope of the ISI initiative and incorporated it into our established Asset Health and Reliability and Capacity programs as well as creating new programs within these budget categories. This increased investment in these core categories will strengthen our system, making it more resilient, reliable, and able to meet the tasks required of a modern grid. As a result, throughout the term of this multi-year rate plan, we will be increasing our investments in our Asset Health and Reliability and Capacity programs with a focus on replacing underground cables, poles, and substation transformers.

During the term of this MYRP, Distribution will continue work on implementing the AGIS initiative including installation of AMI meters and the associated FAN throughout the service territory. As noted, the Company plans to seek recovery for the bulk of the AGIS investments (with the exception of internal labor) through the TCR Rider.

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[6] *In the Matter of Xcel Energy's Integrated Distribution Plan and Advanced Grid Intelligence and Security Certification Request*, Docket No. E002/M-19-666, INTEGRATED DISTRIBUTION PLAN at 32 (Nov. 1, 2019).

From 2021 to 2023, we are also responding to customer expectations by continuing to work on our existing EV programs as well as expanding our EV offerings. This includes work on several pilot programs that were previously approved by the Commission, a Residential EV Service Pilot, Fleet EV Service Pilot, a Public Charging Pilot, and a Residential EV Subscription Service pilot, and a EV Home Service programs[7] as well as pilots and programs highlighted in the Company's 2020 Transportation Electrification Plan filed on June 1, 2020,[8] such as the Multi-Unit Dwelling Charging program. These investments will provide the infrastructure necessary to promote greater EV use, and to meet the demands of the growing EV market. I discuss our EV capital investments and O&M expenses in Section V.

Q. WHAT ARE DISTRIBUTION'S CAPITAL FORECASTS FOR 2021-2023 BY CAPITAL BUDGET GROUPING?

A. Our capital expenditure forecasts for 2021 through 2023 are set forth in Table 5 and Figure 4. Our capital additions forecasts for 2021 through 2023 are set forth in Table 6 and Figure 5. Our individual capital additions are listed in Exhibit___(KAB-1), Schedule 2.

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[7] *See* Docket No. E002/M-17-817; Docket No. E002/M-18-643; Docket No. E002/M-19-186; Docket No. E002/M-19-559.

[8] *In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure*, 2020 TRANSPORTATION ELECTRIFICATION PLAN, Docket No. E999/CI-17-879 (June 1, 2020).

Table 5

2021-2023 Distribution Capital Expenditures

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Expenditures (excludes AFUDC)	**2021 Budget**	**2022 Budget**	**2023 Budget**
Asset Health & Reliability	$144.1	$182.0	$203.2
New Business	$57.1	$60.2	$66.4
Capacity	$45.5	$43.7	$47.8
Mandates	$35.0	$35.5	$38.0
Tools and Equipment	$10.3	$13.4	$11.6
Electric Vehicle Program (EVP)	$11.5	$10.7	$11.9
Solar	$0.0	$0.0	$0.0
Advanced Grid Intelligence & Security (AGIS)	$12.4	$113.3	$108.8
Total	**$316.0**	**$458.7**	**$487.6**

Figure 4

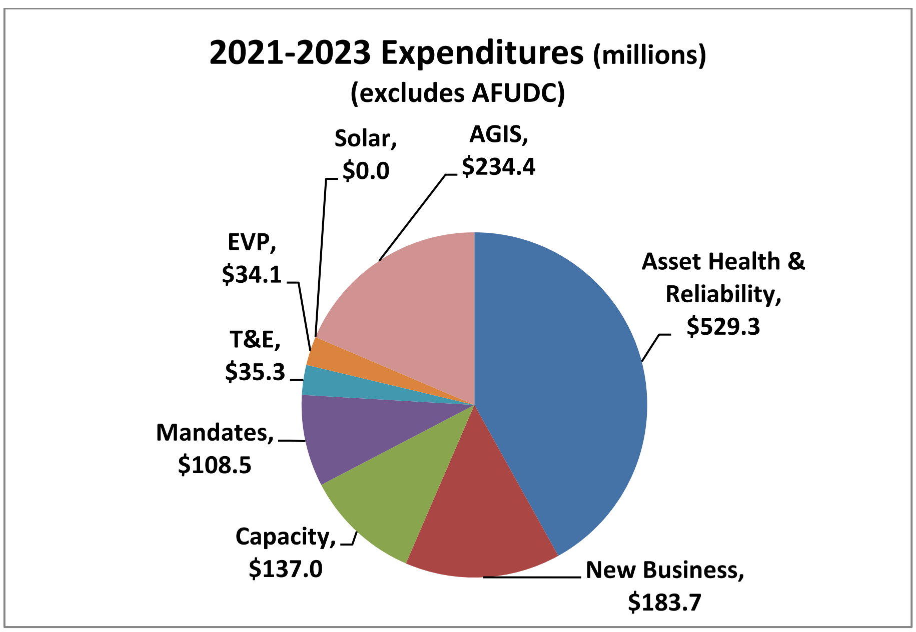


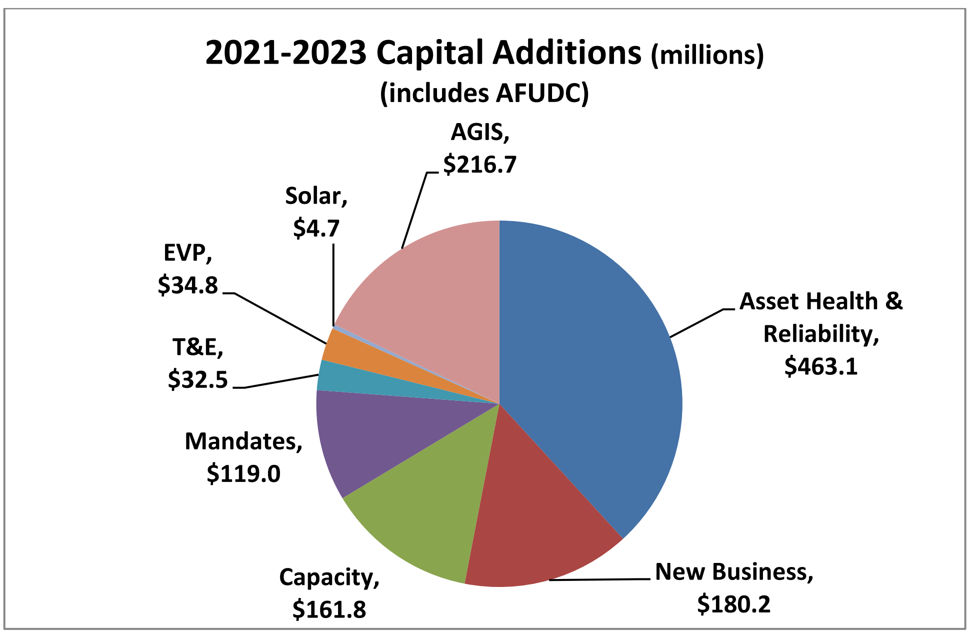
Table 6

2021-2023 Distribution Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2021 Budget	2022 Budget	2023 Budget
Asset Health & Reliability	$127.6	$157.7	$177.9
New Business	$56.0	$59.1	$65.1
Capacity	$58.2	$53.2	$50.3
Mandates	$53.2	$31.2	$34.6
Tools and Equipment	$9.4	$11.3	$11.9
Electric Vehicle Program (EVP)	$11.7	$10.9	$12.2
Solar	$5.7	($1.5)	$0.5
Advanced Grid Intelligence & Security (AGIS)	$13.1	$102.3	$101.3
Total	**$334.9**	**$424.2**	**$453.7**

Figure 5



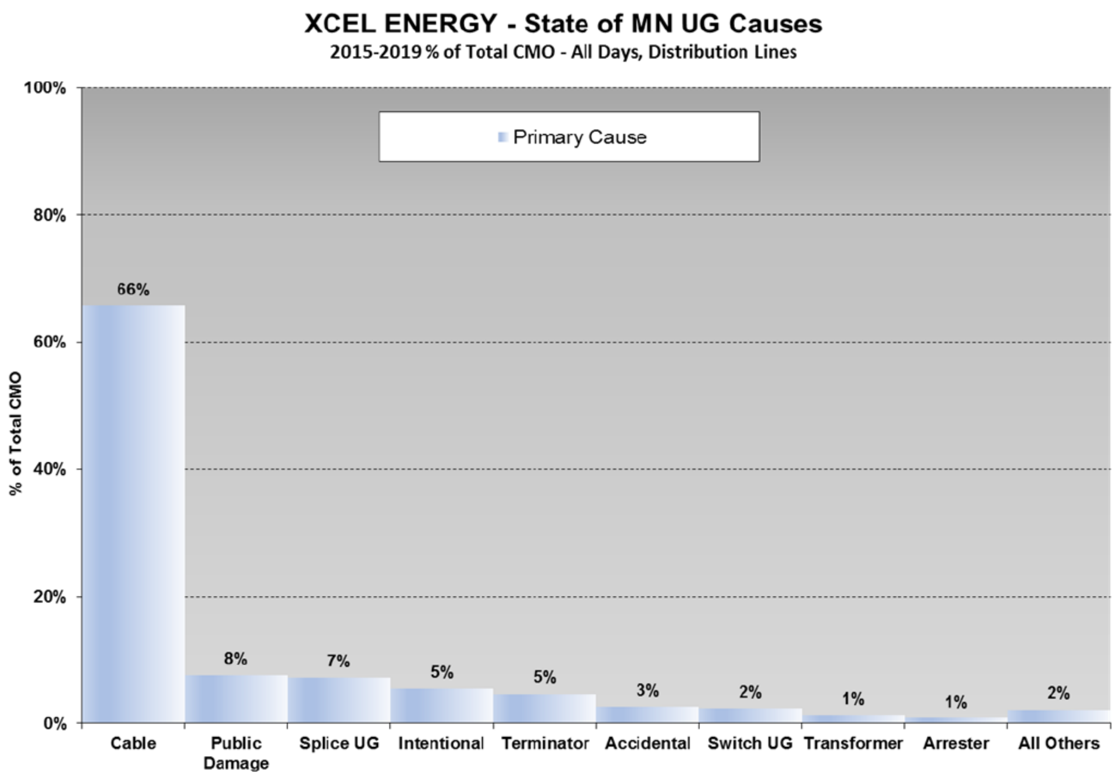
Q. HOW DO DISTRIBUTION'S CAPITAL ADDITIONS FOR 2021 TO 2023 COMPARE TO HISTORICAL TRENDS?

A. As I noted earlier, overall, Distribution's capital investments are increasing in 2021 to 2023 as compared to historical trends. The budget category with the largest growth is Asset Health and Reliability. Our investments in this budget category are crucial to maintaining the reliability and resiliency of our system and ensuring it is poised to meet future demands of a modern grid.

Throughout the term of this multi-year rate plan, we will be placing greater focus on two of our key programs within this category—Routine Cable Replacements and Routine Pole Replacements. Underground cable is resistant to many environmental issues, but outages due to degraded cable can be lengthy. Our current Routine Cable Replacement program aims to identify and replace degraded cable. However, as shown in Figure 6 below, cable failure remains the predominant cause of outages on our underground system accounting for approximately 70 percent of the overall customer minutes out (CMO).

Figure 6

State of Minnesota Underground Outages by Cause



Q. PLEASE DISCUSS THE INVESTMENTS THAT DISTRIBUTION WILL BE MAKING TO ADDRESS THESE CABLE-RELATED OUTAGES.

A. In general, there are two types of cable, mainline cable and residential cable. Given the role of cable failures in customer outages, we our expanding our investments in mainline cable replacements so that we can proactively replace more miles of cable based on their age and condition.

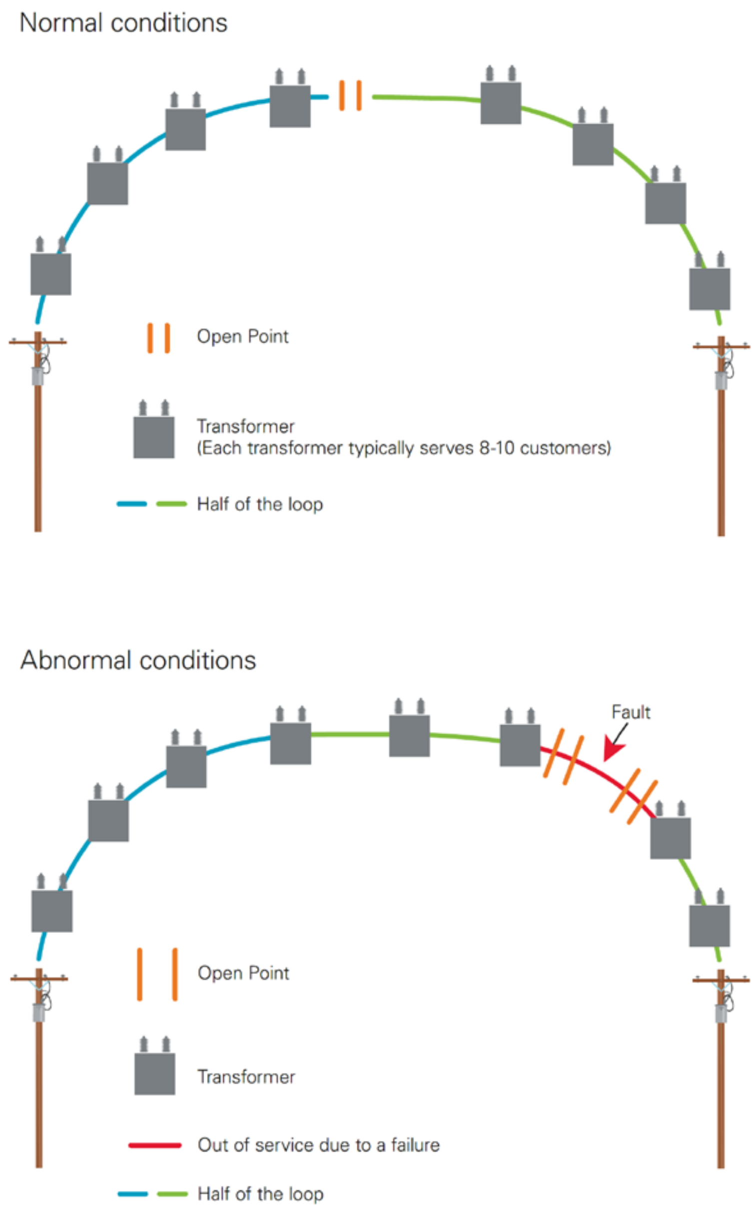
Q. WHAT INVESTMENTS ARE PLANNED DURING THIS MYRP TO ADDRESS UNDERGROUND RESIDENTIAL CABLE-RELATED OUTAGES?

A. On our underground residential distribution system, we will also be proactively replacing a larger portion of our residential distribution cable. As depicted in

Figure 7, a classic underground residential distribution circuit is a loop arrangement (each half loop is depicted as a different color) fed from each end from an overhead circuit or switch cabinets. Under normal conditions, an open point exists in the middle of the loop. If a fault occurs on any section of line, service can be quickly restored by isolating the faulted cable by opening the normally closed switches on either end of the faulted section. The normal open point is then closed, restoring service to everyone. Replacement of the faulted section and the surrounding half loop can then be replaced as schedules allow.

Figure 7

Underground Residential Distribution System



Over the term of this MYRP, we will be replacing the entire half loop rather than replacing segments as sections fail or are found to be in poor condition. This proactive replacement of the entire half loop will avoid additional failures and outages for all customers located on the half loop.

Q. Is Distribution planning to increase its investments in other Asset Health and reliability programs during the term of this MYRP?

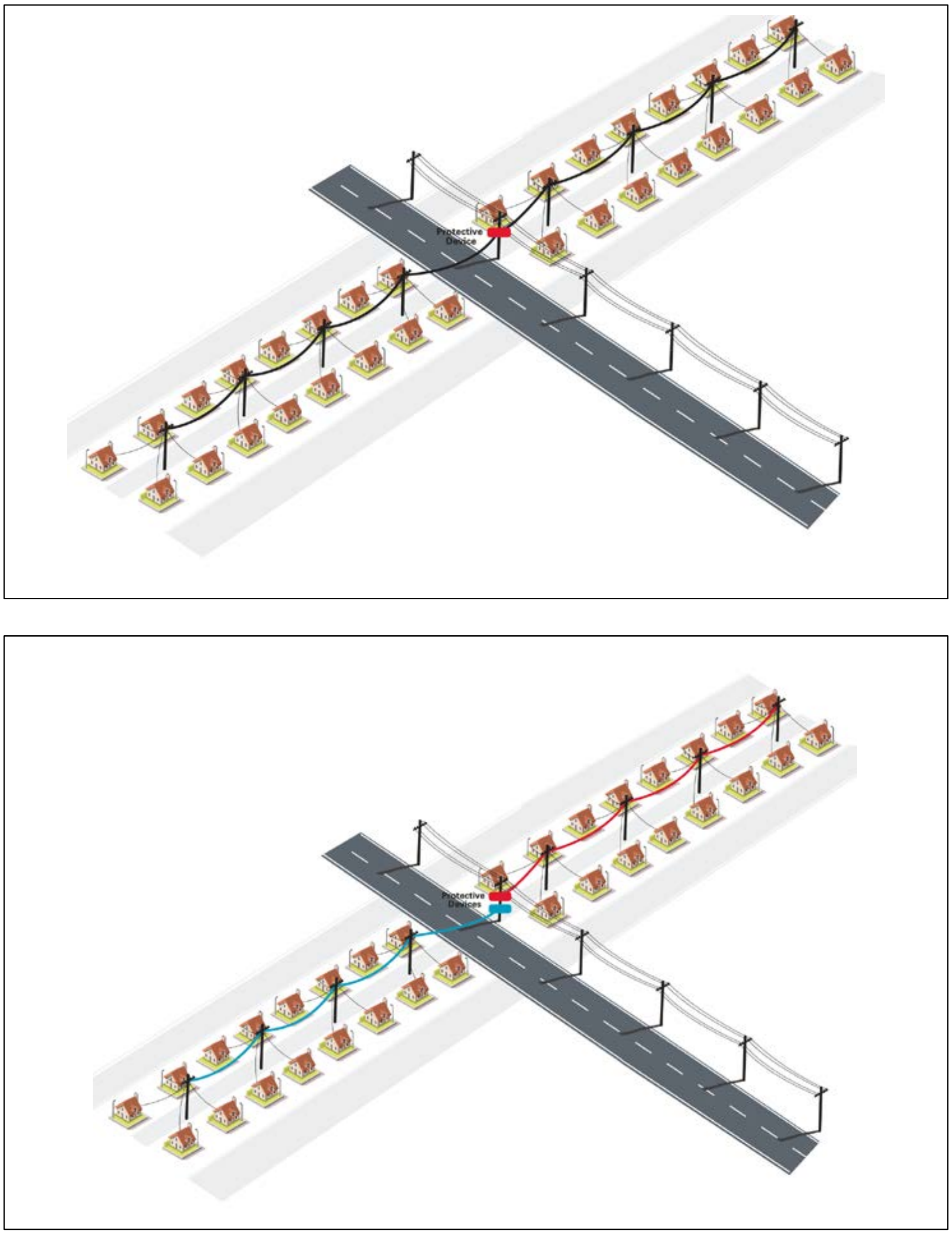
A. Yes, we will also be expanding the number of programs within our Asset Health and Reliability category. Many of these programs were discussed as part of our ISI initiative and have now been absorbed into our established programs. These new programs seek to address reliability issues on the portions of our system that are closest to our customers. An example of one of these new programs is the High Customer Count Tap program.

Q. Please describe the High Customer Count Tap program.

A. Currently, there are approximately 20,000 failures per year on the tap portion of the system that result in an outage for customers. Interruptions from tap protective devices with over 100 customers are responsible for approximately 50 percent of the tap-level SAIDI impact, yet they only represent around 10 percent of the total number of protective devices. The High Customer Count Tap program focuses on redesigning the tap portion of the distribution system to reduce the number of customers that are located behind a protective device. This is because one of the easiest methods to improve the customer reliability experience is to increase the number of protective devices, thus reducing the number of customers "behind" each device, which reduces the number of customers experiencing an outage when a fault occurs. This is depicted in Figure 8 below.

Figure 8

High Customer Count Tap Program



As shown in Figure 8, the installation of the second protective device will reduce the number of customers that are impacted by an outage.

Q. CAN YOU PROVIDE AN OVERVIEW OF INVESTMENTS PLANNED FOR DISTRIBUTION'S OTHER CAPITAL BUDGET CATEGORIES DURING THE TERM OF THE MYRP?

A. Yes. Distribution will also be increasing our investments in Capacity projects between 2021 to 2023 by completing eight large discrete Capacity projects to address potential overload conditions at substations throughout our service territory. We are also investing in new projects to support additional load, such as Feeder Exit Capacity program.

Further, during 2021 to 2023, Distribution will be working to install AMI meters and the associated FAN communication network which will led to increasing capital investments in our AGIS initiative budget category. With the exception of the internal labor component, recovery of these AGIS capital investments will be requested through TCR Rider as discussed by Company witness Mr. Benj Halama.

While Tools and Equipment is a smaller category of investments for Distribution, we will be expanding our investments in this category to complete several cybersecurity projects as well as building out fiber optic communications from our substations to a leased fiber optic cable that will be utilized solely by the Company.

Finally, another area of growth is our investments in EV infrastructure. The Company has received Commission approval for several different pilots and programs aimed at making it easier for more people to use EVs through new charging infrastructure and customer programs.

Q. CAN YOU PROVIDE AN OVERALL VIEW OF DISTRIBUTION'S CAPITAL INVESTMENT TREND FROM 2017 TO 2023?

A. Yes. Our overall 2017 to 2023 capital expenditures and capital additions are set forth in Tables 7 and 8 below.

Table 7

2017-2023 Distribution Capital Expenditures

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Expenditures (excludes AFUDC)	2017 Actual	2018 Actual	2019 Actual	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Asset Health & Reliability	$94.4	$99.7	$95.3	$106.6	$144.1	$182.0	$203.2
New Business	$53.8	$62.2	$55.8	$60.4	$57.1	$60.2	$66.4
Capacity	$13.3	$13.6	$21.6	$49.2	$45.5	$43.7	$47.8
Mandates	$15.4	$28.9	$39.3	$31.7	$35.0	$35.5	$38.0
Tools and Equipment	$2.2	$3.0	$4.2	$5.7	$10.3	$13.4	$11.6
Electric Vehicle Program (EVP)	$0.0	$0.0	$0.6	$3.8	$11.5	$10.7	$11.9
Solar	$4.8	($11.4)	($0.8)	($0.1)	$0.0	$0.0	$0.0
Advanced Grid Intelligence & Security (AGIS)	$0.0	$0.1	$5.6	$1.4	$12.4	$113.3	$108.8
Total	**$184.0**	**$196.2**	**$221.7**	**$258.7**	**$316.0**	**$458.7**	**$487.6**

Table 8

2017-2023 Distribution Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Budget**	**2022 Budget**	**2023 Budget**
Asset Health & Reliability	$81.8	$81.6	$87.3	$105.2	$127.6	$157.7	$177.9
New Business	$50.1	$63.5	$56.3	$51.8	$56.0	$59.1	$65.1
Capacity	$18.6	$10.4	$12.2	$35.3	$58.2	$53.2	$50.3
Mandates	$13.8	$21.6	$29.2	$21.9	$53.2	$31.2	$34.6
Tools and Equipment	($0.5)	$2.8	$2.5	$6.8	$9.4	$11.3	$11.9
Electric Vehicle Program (EVP)	$0.0	$0.0	$0.5	$4.0	$11.7	$10.9	$12.2
Solar	($7.2)	($13.2)	($2.1)	$6.8	$5.7	($1.5)	$0.5
Advanced Grid Intelligence & Security (AGIS)	$0.0	$0.0	$3.3	$2.4	$13.1	$102.3	$101.3
Total	**$156.6**	**$166.8**	**$189.3**	**$234.1**	**$334.9**	**$424.2**	**$453.7**

Tables 7 and 8 illustrate that Distribution's capital investments can vary on a year-to-year basis depending on the specific work that is necessary to meet the needs of both our customers and our business. In certain years, Distribution's capital investments may be lower to support increased investments by other business areas of the Company. Conversely, Distribution's capital investment levels may increase in years when we are working on major initiatives, and capital additions necessarily increase when those initiatives are placed in service.

As can be seen in the tables above, incremental capital additions increases for 2021-2023 over previous years are the result of greater investment in the following budget categories: Asset Health and Reliability, Capacity, and AGIS. As discussed above, this increase in investments in necessary to maintain the safety, reliability, and resiliency of the distribution system and to meet the requirements of a modern grid.

E. Major Planned Investments for 2021 to 2023

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

A. The multi-year rate plan 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 Distribution anticipates making in 2021 through 2023.

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

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

Q. WHAT MAJOR PLANNED INVESTMENTS DOES DISTRIBUTION ANTICIPATE UNDERTAKING DURING THE PERIOD OF THIS MULTI-YEAR RATE PLAN?

A. Distribution anticipates undertaking two major planned investments from 2021 to 2023. These are in our Routine Cable Replacement and Routine Pole Replacement programs. Both of these programs are long-standing programs but during this rate case period, the Company will be making increasing investments in these programs, as depicted in Table 9. These major planned investments, as well as the additional key capital projects Distribution anticipates completing in 2021, 2022, and 2023 are discussed in more detail below.

Table 9

Distribution's Major Planned Investments

	Capital Additions (Dollars in Millions)		
	2021	**2022**	**2023**
Routine Cable Replacements	$32.3	$42.6	$43.6
Routine Pole Replacements	$24.9	$24.0	$23.7

F. Key Capital Additions for 2021 to 2023

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

A. The purpose of this section is to describe key capital projects for Distribution during the term of the multi-year rate plan. For purposes of testimony, we defined key capital projects as those that will have $5 million or more in capital additions between 2021 and 2023. These projects are described in detail below. Unless otherwise stated, all dollar figures in this capital section are State of Minnesota Electric Jurisdiction amounts. Individual project capital additions are listed in Exhibit___(KAB-1) Schedule 2.

1. Asset Health and Reliability

Q. WHAT TYPES OF CAPITAL PROJECTS ARE INCLUDED IN THE ASSET HEALTH AND RELIABILITY CATEGORY?

A. These are projects that we perform each year to address the age and condition of our distribution facilities. To determine which facilities need replacement or repair each year we track the age of our major distribution assets and use age as a proxy for asset health. We also analyze reliability data and work to address those components that have poor reliability performance.

Distribution's investments in Asset Health and Reliability fall into two categories – routine projects and larger discrete specific projects. Routine projects are those that are performed each year to replace aging and worn distribution facilities based on the age profile and overall reliability performance of these facilities. This includes replacement of underground cable, poles, and substation equipment which have reached the end of their life. This category also captures replacements due to storms and public damage.

In addition to these routine projects that we perform each year, Distribution also undertakes non-routine discrete Asset Health and Reliability projects that relate to asset renewal (addressing aging infrastructure with specific conversion or upgrade projects) or reliability (where the age of facilities impacts failures, reliability, and customer outages). Projects are identified based on system needs, and are scored based on our standard budgeting processes and evaluated for funding based on risk score, need, and available funding. Due to the timing of in-service dates, the capital additions for these non-routine discrete projects varies on a year-to-year basis. Table 10 provides an overview of our historical and budgeted investments in Asset Health and Reliability Projects.

Table 10

Asset Health and Reliability – Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Budget**	**2022 Budget**	**2023 Budget**
Asset Health and Reliability							
Routine Cable Replacement	$16.1	$22.3	$18.5	$19.3	$32.3	$42.6	$43.6
Routine Rebuilds and Conversions	$29.8	$22.4	$29.8	$24.9	$27.8	$29.7	$30.5
Routine Pole Replacements	$1.4	$7.4	$7.9	$20.7	$24.9	$24.0	$23.7
Routine Restoration/Failure Reserves	$17.0	$10.5	$8.9	$19.5	$22.1	$17.0	$18.5
Routine Line Renewal Programs	$1.8	$2.6	$4.3	$4.9	$6.2	$15.7	$28.1
Non-Routine Discrete	$9.9	$11.4	$16.3	$14.7	$5.6	$14.9	$14.8
Routine Substation Renewal Programs	$5.7	$4.9	$1.6	$1.3	$8.5	$13.8	$18.8
Total	**$81.8**	**$81.6**	**$87.3**	**$105.2**	**$127.6**	**$157.7**	**$177.9**

Q. TABLE 10 SHOWS INCREASING CAPITAL ADDITIONS IN THE ASSET HEALTH AND RELIABILITY CATEGORY BETWEEN 2021 AND 2023. PLEASE EXPLAIN THESE INCREASES.

A. This increasing trend is driven by greater investments in several of our main Asset Health and Reliability programs. In particular, we plan to invest more in our routine cable replacement program, routine pole replacement program, line renewal program, and substation renewal program. These additional investments are needed to address the condition of aging infrastructure that is key to the reliability and resiliency of our system. In addition, over the term of this multi-year rate plan, we plan to make additional investments to focus on more proactive replacements to address these aging assets before they fail. This more proactive approach to our aging infrastructure will further improve system reliability.

a. Routine Cable Replacement Program

Q. DESCRIBE THE ROUTINE CABLE REPLACEMENT PROGRAM.

A. The NSPM distribution system has nearly 1,500 miles of underground feeder cable and over 9,100 miles of underground tap cable. Cable failures are a main contributor to outages for customers who are served by underground facilities and account for approximately 70 percent of the customer minutes out (CMO) on the underground system from 2015 to 2019. This program replaces both failed cables and proactively replaces cable prior to failure. Proactively replacing cable allows us to avoid a potential outage caused by a cable failure and utilize a systematic approach in the replacement of this asset. There are two primary subcategories of investment within the routine cable replacement program: (1) mainline cable replacements and (2) underground residential distribution cable replacement.

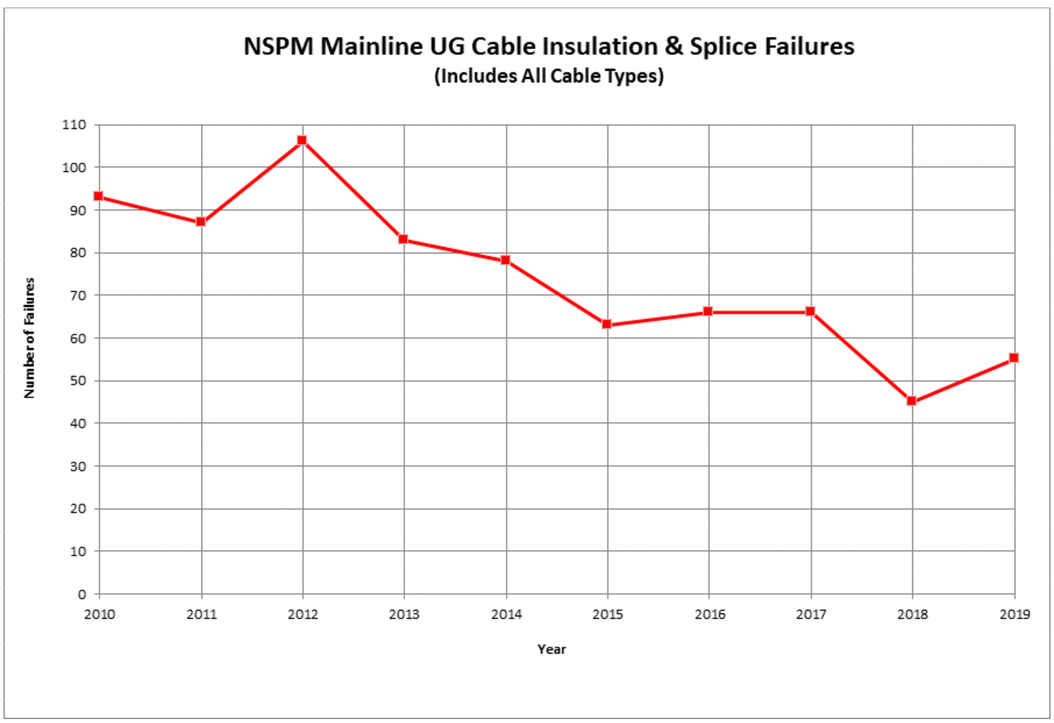
Q. WHAT ARE MAINLINE CABLE REPLACEMENTS?

A. Nearly 25 percent of the Company's underground cable in Minnesota is a type of cable (non-jacketed cross-linked polyethylene (XLPE) cable that was installed prior to 1985) that is more prone to failures and has a shorter useful life (approximately 35 years) than newer cable types that we currently install. To address this issue, since 2014 we have been replacing non-jacketed cable that has failed or reached the end of its life with jacketed cable in Minnesota. Even with these investments, there is still approximately 250 miles of non-jacketed mainline cable in Minnesota. Over the term of this multi-year rate plan, we will be making increasing investments to more quickly replace the poorest performing legacy jacketed mainline cable on our system. Even with the increased funding over the term of this MYRP, it will take approximately nine years to replace all of the non-jacketed mainline cable on our system.

Q. HOW WILL THIS INCREASED INVESTMENT IN MAINLINE CABLE REPLACEMENTS BENEFIT CUSTOMERS?

A. We have been working on addressing this issue with non-jacked mainline cable since 2014 and as shown in Figure 9 below, these investments have contributed to reducing the number of mainline cable failures per year and improving reliability for our customers. With this additional funding, we expect to be able to reduce these cable failures even more.

Figure 9



Q. WHAT ARE UNDERGROUND RESIDENTIAL DISTRIBUTION CABLE REPLACEMENTS?

A. An underground residential distribution system is comprised of an underground circuit, in a loop arrangement, segmented by distribution transformers. Within each loop, there is a normally open point which is a segment of conductor that is disconnected from a transformer. In the event of a failure on another segment in that loop, the crew can perform switching operations to restore power to a majority, if not all, of the customers within that loop by changing the normal open point to the failed cable segment. The faulted cable can then be repaired or replaced under a scheduled and planned project, rather than under emergency conditions.

Historically, the Company had been making segment replacements as particular sections fail. Between 2021 and 2023, we are increasing funding for Underground Residential Distribution (URD) cable replacement to replace half loops on failed cables. In other words, we will be replacing not just the failed span but also the entire half loop. This is depicted in Figure 7 above.

Q. HOW WILL PROACTIVELY REPLACING URD CABLES BENEFIT CUSTOMERS?

A. Once a failure occurs on a segment, replacing the half loop of the segment benefits the customers on that entire loop by avoiding future failures of other segments. Because cable loops are of similar vintage and type of cable (they were installed at the same time originally), once repeated failures have occurred within that loop, it is only a matter of time before additional failures occur, both affecting customer reliability and customer experience. The Company has had many cases where after the first three failures in a half loop, successive failures occur in more rapid succession. By replacing the half loop, instead of just segment replacement, the Company aims to avoid additional failures and outages for those customers.

In addition, proactive replacement allows us to replace the cable before it fails becoming unrepairable and leading to an emergency replacement. Emergency replacements leave the system with less redundancy and switching options, which can lead to lengthy outages when additional failures occur.

Q. HOW WAS THE BUDGET FOR THE ROUTINE CABLE REPLACEMENT PROGRAM DEVELOPED?

A. The budget for this category is developed based upon historical trends of failure/fault rates and reliability needs. The work occurs throughout the year, with the greatest portion of the work taking place during months without frost to minimize expense. The specific sections of cable selected for replacement are chosen based on reliability data, and in some cases, selections are influenced by historical performance of the types and vintages of cable. We have also included in the budget for 2021 through 2023 additional funds to make the proactive cable replacements I discussed for both mainline and URD cable. This proactive approach will improve reliability by further reducing outages caused by a cable failure.

b. Routine Pole Replacement Program

Q. DESCRIBE THE ROUTINE POLE REPLACEMENT PROGRAM?

A. The NSPM distribution system has approximately 525,000 wooden poles in service. Pole longevity can vary widely based on the wood species, treatment and the environment where it is placed but poles have a useful life, on average, of approximately 50 years. As part of our Routine Pole Replacement Program, Distribution inspects our poles, treats deteriorating poles, and replaces poles that have reached the end of their life.

Q. HOW OFTEN DOES DISTRIBUTION INSPECT ITS POLES?

A. Xcel Energy aims to tests its poles on a 12-year inspection cycle, which amounts to approximately 8.3 percent of poles each year. However, the actual number of poles inspected each year varies as budget pressures may result in the need to reduce funds allocated to pole inspections to fund higher priority needs within Distribution or other business areas.

Q. PLEASE DESCRIBE THE POLE INSPECTION PROCESS.

A. The inspection process includes a visual, sound and bore, and/or excavation inspection (i.e., hand digging around the base of pole). Depending on the results of this inspection, poles will either be treated or replaced as appropriate. The determination of whether or not a pole needs to be treated or replaced depends on the remaining strength of the pole and existence of any above ground deterioration (i.e., insulator decay).

If a pole has less than 70 percent of its initial strength left or exhibits above ground deterioration, the pole is replaced. If a pole needs to be replaced, we typically plan to replace the pole the following year unless the pole is in such poor condition that it requires immediate replacement. While we plan to replace poles within one year of a failed inspection, in certain years, other budgetary pressures may mean that certain poles are not replaced in the following year. Distribution prioritizes pole replacement based on a pole's likelihood of failure using the percentage of original strength left in the pole as the guide. Based on this prioritization, Distribution replaces those poles with the lowest percentage of remaining strength before those poles with a higher percentage of remaining strength.

Q. How is the budget for the Routine Pole Replacement program developed?

A. Our budget for pole inspections is based on an assumption that we will inspect one twelfth of all of our poles each year and that approximately 12 percent of inspected poles will need to be replaced. Pole replacement costs are estimated on a per-pole basis, using historical data and any known anticipated changes in labor and material costs.

Q. Why are investments in the Routine Pole Replacement program increasing over the term of this multi-year rate plan?

A. Our investments in this area are increasing starting in 2021 due to several factors. First, our budget for this program over the term of this multi-year rate plan provides funding to inspect one twelfth of all of our poles each year. Table 11 below provides a break-down of the number of inspections that are forecasted or budgeted to be performed each year from 2020 to 2023. As shown in Table 11, the number of pole inspections performed each year is increasing as we have budgeted to inspect one twelfth of all poles each year from 2021 to 2023.

Table 11

Pole Inspections Per Year in Minnesota

Year	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Number of Pole Inspections	32,701	45,736	55,608	53,522

As I noted above, in certain years, Distribution has been unable to maintain this inspection rate due to budgetary pressures that require us to shift funding to address more immediate concerns. Given the condition and age of our facilities, it is important that Distribution maintain a steady inspection schedule so that any issues with our poles can be identified and rectified prior to a pole failure.

Q. ARE THERE OTHER FACTORS THAT ARE LEADING TO THE INCREASE IN POLE REPLACEMENTS?

A. Yes, in recent years we have seen a higher than average rejection rate for inspected poles. A "rejection" refers to a pole that has failed inspection and testing and needs to be replaced to ensure the physical integrity of the poles. For instance, in 2018 and 2019 the rejection rate was approximately 13 percent per year whereas the average historical rejection rate for poles inspected for NSPM is approximately nine percent. I note that our year-to-date rejection rate for poles inspected in 2020 is approximately 14 percent. While the rejection rate for poles can fluctuate each year based on the age and condition of the particular poles inspected in that year this recent increase in the rejection rate underscores the need to place greater focus on inspection, repair, and replacement of these key assets.

Table 12

NSPM Pole Rejection Rates By Year

Year	Rejection Rate
2019	13.2%
2018	13.7%
2017	9.5%
2016	10.4%
2015	11.0%
2014	10.2%
2013	9.5%
2012	7.3%
2011	4.7%
2010	4.6%

This increase in the rejection rate has resulted in the need to replace a greater number of poles in recent years. As depicted in Table 13, the higher rejection rates in 2018 and 2019 resulted in increased pole replacements in the following year. Another driver of the increase in pole replacements in 2020 is the need to address a backlog of pole replacements identified in prior years.

Table 13

NSPM Pole Replacements By Year

Year	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Number of Pole Replacements	1,700	1,750	1,312	1,780	4,600	4,900	4,500	5,061

Over the term of the multi-year rate plan, we will be inspecting more poles per year, and we expect that our pole rejection rate will be in line with these recent trends of approximately 12 percent per year. Both of these factors will result in a higher number of pole replacements from 2021 to 2023. Finally, another component of the increase in this budget category is increases in the cost of pole replacements.

c. Routine Rebuilds and Conversions

Q. DESCRIBE THE ROUTINE REBUILDS AND CONVERSIONS?

A. The bulk of this category is for smaller rebuild and conversion projects that occur during a given year. The rebuild projects include replacing poles due to public damage or minor storm damage. The conversion projects relate to undergrounding overhead lines, generally at the request of customers or government entities (portions of these conversions may be paid for by the customer).

Q. HOW IS THE BUDGET FOR ROUTINE REBUILDS AND CONVERSIONS PROGRAM DEVELOPED?

A. The budget for this program is based on historical trends. There is variation in the year-to-year investments in this category based on the unpredictable nature of both storms and public damage.

Q. PLEASE DISCUSS THE CAPITAL INVESTMENT TRENDS FOR ROUTINE REBUILDS AND CONVERSIONS FOR 2021 TO 2023?

A. Over the course of this multi-year rate plan, our capital budgets for routine rebuilds and conversions is fairly flat with slight increases year-over-year related to inflation as well as higher actual capital expenditures in 2019 that are in turn reflected in the 2021 to 2023 budgets.

d. Routine Line Renewal Program

Q. DESCRIBE THE ROUTINE LINE RENEWAL PROGRAM?

A. This program consists of several smaller subprograms including: (1) network asset renewal; (2) feeder performance improvement program; and (3) pole top reinforcement. Our network asset renewals include investments in the replacement of protectors, transformers, and vault tops. Our feeder performance improvement program aims to rebuild specific feeders that have a history of poor performance. The pole top reinforcement program identifies and replaces of pole top equipment and poles (due to pole top degradation) that have reached the end of their useful life. Pole top equipment includes cross-arms, braces, and insulators.

Over the term of the multi-year rate plan, Distribution will be adding to these programs with several new programs to further these same objectives. Many of these programs were initially part of the ISI initiative and include:

- *Targeted Undergrounding Program* with the goal to underground outage-prone tap lines to reduce the likelihood of these outages and to enable our crews to focus restoration efforts on other areas of the system allowing for quicker response times for all customers.
- *Cable Assessment and Life Extension Program* uses a cable assessment technology to assess and rehabilitate cable through use of partial discharge diagnostics to precisely assess the overall condition of the cable system and make recommendations on how to rehabilitate cables to like-new manufacturer standards.
- *Porcelain Cutouts Program* focuses on replacing porcelain cutouts with polymer cutouts. Cutouts are used to provide overcurrent protection on overhead feeders. As compared to porcelain, polymer cutouts have

better cold weather reliability, are more durable during transit and installation, and have superior mechanical toughness.

- *High Customer Count Taps Program* focuses on redesigning the tap portion of the distribution system to reducing the number of customers that are located behind the protective device to an average of 40 to 50 customers. Redesigns will generally employ one of three solutions – adding phases, interjecting another source, or subdividing the tap.
- *Transformer and Secondary Replacement Program* targets replacement of distribution transformers throughout the system that are undersized and at risk of overloads and the replacement of aging secondary wire that is degraded and at risk of failure.
- *Pole Fire Mitigation Program* seeks to reduce the risk of pole fires by identifying poles that are at risk for fire and then replacing certain components (enhanced insulation, replacing wooden cross-arms with fiberglass) or when necessary, replacing the pole or relocating the line away from airborne contaminants.

Q. HOW DO THE INVESTMENTS IN THE ROUTINE LINE RENEWAL PROGRAM BENEFIT CUSTOMERS?

A. These investments are targeted at key aspects of the distribution system that are closest to our customers and aims to improve the reliability and resiliency of that portion of the system. For instance, the Pole Fire Mitigation Program aims to reduce the likelihood of pole fires and the associated service interruptions. In Minnesota, the poles located along busy roads often support higher capacity distribution lines providing service to a large number of customers. These poles are also exposed to a higher concentration of de-icing chemicals used on roadways in the winter. These chemicals can build up on the pole and make the surface conducive to pole fire initiation. Pole fires can have a large impact on reliability due to the fact that they often result in an extended outage and can impact more customers since these fires often involve higher capacity lines. We average more than 14 mainline pole fires each year, and each mainline pole fire impacts more than 1,500 customers when the outage occurs. By addressing those poles that are at greater risk for poles fires we expect to reduce the number of pole fires and associated outages on our system.

Q. HOW IS THE BUDGET FOR THE ROUTINE LINE RENEWAL PROGRAM DEVELOPED?

A. For our existing programs, these budgets were developed based on historical trends and failure rates. For our new programs, we developed these budgets based on an assessment of the age and condition of the particular portions of the system targeted by that program and then prioritizing replacements based on that assessment.

Q. WHY ARE CAPITAL ADDITIONS FORECASTED IN THE ROUTINE LINE RENEWAL PROGRAM MARKEDLY GREATER IN 2022 AND 2023 AS COMPARED TO 2021?

A. The increase in capital additions for Routine Line Renewal are driven primarily by investments in the new programs I discussed above. The High Customer Count Tap program and Porcelain Cutout program will have capital additions beginning in 2022 and the remaining programs will add plant additions in 2023.

e. Routine Substation Renewal Program

Q. DESCRIBE THE ROUTINE SUBSTATION RENEWAL PROGRAM.

A. This program is focused on improving the reliability and resiliency of the Company's 224 substations in Minnesota through the replacement of key substation components. In addition, this program also looks for opportunities, where it makes sense, to replace the bulk of equipment at a single substation rather than replacing these individual components of a substation on a piecemeal basis. This program also includes investments to replace our mobile transformers that have reached the end of their life.

Q. WHAT ARE THE KEY COMPONENTS OF A DISTRIBUTION SUBSTATION?

A. One of the key assets in any substation is the transformers. Substation transformers are a fundamental to the reliability of our distribution system and are also one of the most expensive components of the substation. While the failure of transformers is not a common occurrence, when a substation transformer fails, the consequences are high as it often results in between 5,000 to 15,000 customers losing service. In addition to transformers, there are several other important components to a substation such as breakers, relays, fences, regulators, and Remote Terminal Unit (RTUs)/Local Control Unit (LCUs) that also must be maintained in working order.

Q. WHAT ARE MOBILE TRANSFORMERS AND SUBSTATIONS?

A. Mobile transformers and substations are large, trailer-based equipment designed to temporarily provide power during an emergency outage or provide support for construction projects to allow for safe, de-energized working conditions.

Q. HOW DOES THE ROUTINE SUBSTATION RENEWAL PROGRAM BENEFIT CUSTOMERS?

A. Replacing these key components of the substation will improve the reliability of our substations. In addition, by upgrading this equipment, the new equipment will have additional functionality that will allow for improved communication and monitoring of the substation equipment. Further, the mobile transformers and substations benefit customers by providing power during an emergency outage.

Q. HOW IS THE BUDGET FOR THE ROUTINE SUBSTATION RENEWAL PROGRAM DEVELOPED?

A. We select and prioritize the replacement of these substation components using several factors, including the age and condition of equipment, amount and type of load served, system reliability, and future load growth. Starting in 2021, we have added funding to this program to replace additional transformers and breakers each year as compared our prior investments.

Q. WHY IS GREATER FUNDING NEEDED FOR TRANSFORMER REPLACEMENTS OVER THE TERM OF THE MYRP?

A. The age and condition of our existing substation transformers requires that we replace more of these assets in the coming years. To identify those needing replacement, we monitor the health of substation transformers by performing a dissolved gas analysis (DGA) of the transformer fleet on a regular basis. Transformer readings that indicate the unit is at risk of failure may be proactively taken out of service and replaced. We also consider the average useful life and age of individual assets. The average useful life of a distribution substation transformer is 40 years; beyond 40 years, the probability of failure begins to increase. As of the end of 2019, we had approximately 540 substation transformers on the NSP System and as of 2017, our most recent asset study, 129 transformers or 28 percent were older than 45 years. Currently, the Company replaces approximately two substation transformers per year that have been identified as needing replacement due to their age and/or condition.

Xcel Energy has budgeted additional funding for this program to increase this replacement rate to approximately eight transformers per year.

Q. WHY IS ADDITIONAL FUNDING NEEDED FOR MOBILE SUBSTATIONS AND TRANSFORMERS OVER THE TERM OF THE MYRP?

A. Xcel Energy currently has a mobile substation fleet of 14 units and three mobile transformers used across the NSP System. Eleven of these units are beyond the typical operating lifespan (52-73 years) and are experiencing more frequent maintenance and therefore reduced reliability. Further, two units are no longer functioning and are in the process of being retired. In 2022 and 2023, we have budgeted to purchase two or three mobile substations and transformers each year to begin renewing of existing fleet of these key assets.

f. Routine Restoration/Failure Reserves

Q. DESCRIBE THE ROUTINE RESTORATION/FAILURE RESERVE BUDGET CATEGORY.

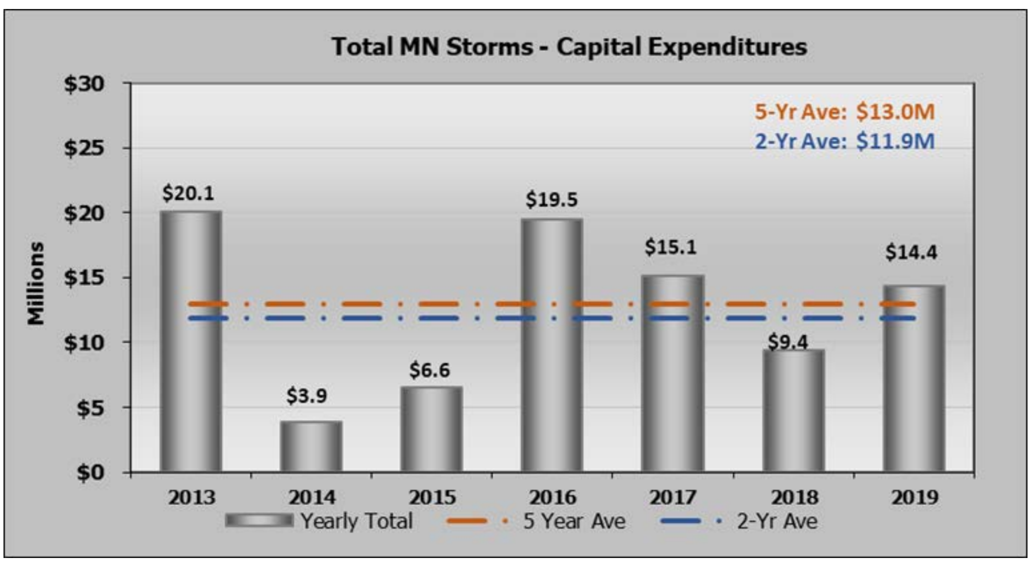
A. This category includes investments required to repair facilities that are damaged during storm events as well as to address substation equipment failures. Xcel Energy has a strong track record related to storm restoration and these investments are key to our ability to restore power quickly and safely after a severe weather event. This budget category also includes investments in back-up transformers that are needed to quickly address transformer failures throughout the system.

Q. HOW IS THE BUDGET FOR THE ROUTINE RESTORATION/FAILURE RESERVE BUDGET CATEGORY DEVELOPED?

A. This budget is developed based on the five-year storm average as well as historical failure rates for substation transformers. As shown in Figure 10, the unpredictable nature of severe weather makes budgeting challenging as there is no "typical" year for severe weather. In terms of budgeting for storm restoration, due its significant variability from year-to-year, we budget dollars in a working capital fund based on the five-year average for storm restoration expense. This storm restoration budget is not assigned to a specific project or program. When emergent circumstances, such as storm restoration arise, we reallocate budgeted dollars to address the circumstance while remaining in balance with our overall annual budget.

Figure 10

Historical Storm Capital Expenditures



Q. HOW IS THE FAILURE RESERVE BUDGET TRENDING OVER THE COURSE OF THIS MULTI-YEAR RATE PLAN?

A. Our investments in this budget category are expected to remain steady over the course of the multi-year rate plan. As I noted, since the majority of the capital additions in this budget category relate to storm restoration, there can be budget variations between years based on the severity and frequency of actual storm events.

g. Non-Routine Discrete Projects

Q. WHAT IS INCLUDED IN THE NON-ROUTINE DISCRETE BUDGET CATEGORY?

A. This budget category includes specific larger projects related to the replacement of aging infrastructure and/or reliability focused projects. These projects are called out as non-routine discrete projects due to the size of the associated capital investments as well as the larger scope of the project.

Q. HOW IS THE BUDGET FOR THE NON-ROUTINE DISCRETE DETERMINED?

A. The budget for this category is based on identified age, condition, or reliability issues related to a particular feeder or a substation.

Q. WHY ARE THE CAPITAL INVESTMENTS FOR NON-ROUTINE DISCRETE PROJECTS INCREASING STARTING IN 2022 AND CONTINUING THROUGH 2023?

A. This increase in capital investments is the result of several larger rebuild projects that will have plant additions in years. These projects, which I discuss in greater detail below, involving rebuilding distribution lines and substations in several communities.

Q. WHAT KEY NON-ROUTINE DISCRETE PROJECTS WILL DISTRIBUTION UNDERTAKE DURING 2021 TO 2023?

A. There are four key non-routine discrete Asset Health and Reliability projects that the Company will undertake during these years: (1) St. Paul Tunnel Relocation; (2) rebuild of Sacred Heart distribution line; (3) Clarks Grove Project; and (4) rebuild of West St. Cloud to Millwood distribution line.

Q. DESCRIBE THE ST. PAUL TUNNEL RELOCATION PROJECT.

A. This project will improve the safety and security of our underground distribution facilities in St. Paul by eliminating the risk of system outages to downtown St. Paul if the tunnels were to collapse.

The electric distribution and network infrastructure in and around downtown St. Paul is housed underground in a sandstone tunnel system that was built in the late 1800s. There are approximately 10 miles of tunnels, and they vary in width and depth. The tunnels are made in sandstone and are eroding internally, causing a build-up of sand and debris within the tunnels; flooding can then cause complete blockage of the tunnels based on the washed-out debris. The placement of utility infrastructure in them is problematic and poses a potential hazard for our employees. Further, the tunnels are shared with other utilities, which can impact the safety and reliability of our system based on failure of the assets not owned or maintained by our Company, which may cause residual impacts to our electrical assets.

Under this program, we would build new infrastructure to retire and replace the existing tunnel system. This will include constructing new underground manhole and duct infrastructure, in accordance with current Company standards, city requirements – and in consideration of safe practices for our employees. Existing electrical facilities would be relocated from the old tunnel system and into the new duct system as it is constructed. These improvements will also address the access and security issues associated with these tunnels.

Q. WHAT ARE THE ACCESS AND SECURITY ISSUES ASSOCIATED WITH HAVING DISTRIBUTION FACILITIES LOCATED IN THE ST. PAUL TUNNELS?

A. Assess to the St. Paul tunnels is time-consuming and difficult. Accessing the tunnels is done in a variety of ways, including doorways built into bluffs and manhole access from street grade. As depicted in the photo in Figure 11 below, our employees, when entering the tunnels from a street-level manhole, use long ladders to climb down to the grade in which our electrical assets are housed, as many tunnels are 30 to 50 feet below street grade. They are then working out of cell phone range, and may face issues with communication, particularly in an emergency situation.

Figure 11

Photo of St. Paul Tunnel Access

Q. WHEN WILL THE ST. PAUL TUNNEL RELOCATION PROJECT BE COMPLETED?

A. The length, condition, and location of the tunnels presents unique construction challenges that will require extensive city, community and customer coordination, detailed planning and engineering, and system operations considerations to ensure service is maintained to all customers currently served by these parts of our electrical system. We expect, given these challenges and required coordination, this project may take up to 15 years to complete. We expect however that the first assets will be placed in service in 2021. These first assets will include the first conduit vaults and duct vaults that will be required to move our electrical equipment out of the tunnels. This project has capital additions of $11.0 million during the rate case period ($1.9 million in 2021, $4.3 million in 2022, and $4.8 million in 2023).

Q. DESCRIBE THE SACRED HEART REBUILD PROJECT.

A. The 20-mile Sacred Heart feeder that connects Belview and Delhi, Minnesota needs to be rebuilt due to the age and condition of the existing poles and associated infrastructure. Certain poles along this feeder are between 60-80 years old and are in poor condition. In addition, this feeder also experiences reliability issues due to failing equipment such a broken conductors and broken crossarms and insulators. This project is currently under construction. The Sacred Heart Rebuild project is planned to be in service in 2022 with a total plant addition of $4.2 million.

Q. PLEASE DESCRIBE THE CLARKS GROVE PROJECT.

A. The Clarks Grove Project is a substation rebuild project needed for reliability and safety due to the age of the substation and associated equipment. As part of this project, we will be upgrading the existing transformer from 8 MVA to 28 MVA to provide additional capacity. This will provide capacity needed to accommodate additional load from the nearby Waseca Substation that is currently near capacity. The increase in the capacity of the Clarks Grove Substation will also help alleviate potential overload conditions on the feeders from the Waseca and Clarks Grove substations when certain elements of the system are out of service. The project is currently in the planning phase and will move to the design phase in early 2021 with a planned in service in 2022. This project has a total plant addition of $2.0 million in 2022.

Q. DESCRIBE THE WEST ST. CLOUD TO MILLWOOD REBUILD PROJECT.

A. This project involves the rebuilding of the distribution feeder that is underbuilt on the West St. Cloud – Millwood 69 kV transmission line. The transmission line is being rebuilt due to the age and condition of the existing line. When the transmission line is rebuilt the distribution underbuild located on the transmission poles will need to be rebuilt as well. Approximately 21 miles of distribution line is being replaced, affecting several different feeders. The voltages of the distribution lines are 4.16 kV, 12.47 kV, or 34.5 kV depending on the feeder. These feeders are being rebuilt in three different phases over the course of three years starting in 2021. Phase 1 of this three year project is beginning in fall of 2021, phase 2 will begin in 2022, and phase 3 will begin in 2023. The West St. Cloud to Millwood Rebuild project is planned to be in service in 2023 with a total plant addition of $4.9 million.

2. New Business

Q. WHAT TYPES OF PROJECTS ARE INCLUDED IN THE NEW BUSINESS CATEGORY?

A. Projects in this category are related to extending electric service to new customers or to support increased loads from existing customers. To serve a new customer, we must generally, at a minimum, extend our distribution system from the nearest practical point and install a transformer, a service extension, and meter(s). Our capital investments in this category include installation or expansion of feeders, primary and secondary extensions, service laterals, transformers, meters, and street lights. Table 14 provides a breakdown of the components that comprise the New Business category of capital additions.

Table 14

New Business – Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	**2017 Actual**	**2018 Actual**	**2019 Actual**	**2020 Forecast**	**2021 Budget**	**2022 Budget**	**2023 Budget**
New Business							
Extensions / Services	$27.58	$29.99	$32.86	$27.28	$27.20	$30.28	$34.31
Transformer Purchases	$15.84	$26.00	$16.04	$17.39	$22.82	$22.82	$24.80
Meter Purchases	$5.71	$5.31	$6.84	$6.27	$5.62	$5.62	$5.62
Street Lighting	$0.96	$2.18	$0.58	$0.88	$0.39	$0.37	$0.38
Total	**$50.1**	**$63.5**	**$56.3**	**$51.8**	**$56.0**	**$59.1**	**$65.1**

Q. HOW DO YOU DEVELOP A BUDGET FOR NEW BUSINESS INVESTMENTS?

A. Our budget for New Business is driven primarily by economic growth. New business budgets are based on meter set forecast and estimated cost-per-meter. Meter growth rates are based on the Company's forecasted customer growth rates. Company witness Ms. Jannell E. Marks discusses the Company's forecasted customer growth rates for the multi-year rate plan in greater detail.

As explained by Ms. Marks, as the economy begins to recover we expect to see customer growth in 2021 but not as high as pre-pandemic levels. This growth is expected to carry into 2022 and 2023 as the expected economy recovery continues.

Q. WHAT ARE THE MAJOR COST DRIVERS FOR 2021 TO 2023 IN THE NEW BUSINESS CATEGORY?

A. We expect our investments in New Business to increase from 2021 to 2023 as the economy begins to recovery from the impacts of COVID-19. However, I note that economic conditions impact our new business investments and the economic recovery may not be as quick as we project, or another economic downturn could also occur. These circumstances would reduce our anticipated investments, while a faster than anticipated economic recovery could increase our New Business capital additions.

3. Capacity

Q. WHAT TYPES OF PROJECTS ARE INCLUDED IN THE CAPACITY CATEGORY?

A. Our Capacity investments include projects associated with upgrading or increasing capacity to handle load growth on the system and to serve load when other elements of the distribution system are out of service. This includes installing new or upgraded substation transformers and distribution feeders. Capacity projects generally span multiple years and are necessitated by increased load from either existing or new customers. I discuss eight of our larger capacity projects that we will be completing between 2021 to 2023 below.

During the term of this multi-year rate plan, we will also be funding several new programs within the Capacity category, such as the Feeder Exit Capacity program.

Q. HOW DO YOU ESTABLISH THE BUDGET FOR CAPACITY PROJECTS?

A. To identify our discrete capacity projects, Distribution capacity planners annually evaluate the peak loading on the substation transformers and feeders. Risks are identified, and solutions examined using a risk-versus-cost methodology. For the new projects and programs within this budget category, we based the budget on the specific scope of work planned during the term of the multi-year rate plan. The resulting budget seeks to most effectively invest the resources both within the Capacity category and across the other categories as well. Table 15 provides a summary of the capital additions budget for Capacity projects for 2021 to 2023.

Table 15

Capital Additions – Capacity

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2021 Budget	2022 Budget	2023 Budget
Capacity	$58.2	$53.2	$50.3

Q. WHAT IS DRIVING THE INCREASE IN CAPACITY INVESTMENTS STARTING IN 2021 AND CONTINUING THROUGH 2023?

A. The increase in capacity investments is driven by several factors. First, we are investing in new projects and programs within the Capacity category to support additional load, such as the Feeder Exit Capacity program. The increase is also driven by eight large discrete Capacity projects that the Company will undertake during these years: (1) Plymouth Area Upgrade Project; (2) Wilson Substation Project; (3) Raptor Substation Project; (4) Stockyards Substation Project; (5) Hyland Lake Substation Project; (6) Elm Creek Substation Project; (7) Western Substation Project; and (8) the Minnesota Feeder Load Monitoring Project. I will describe these projects below.

Q. WHAT IS THE FEEDER EXIT CAPACITY PROGRAM?

A. The purpose of the Feeder Exit Capacity program is to identify areas of the distribution system where the overall load carrying capacity feeder circuits are limited by undersized cables, conductors, or other equipment at the feeder's head end. The program will benefit customers by improving the existing distribution system's ability to accommodate new load growth including EV charging. Increasing the capacity of the feeders will also reduce the overall loading on the feeder circuits, which in some cases can prevent premature equipment failure, therefore improving reliability.

The overall load carrying capacity of a feeder circuit is determined as the minimum series element's capacity rating on the feeder circuit between the feeder bay in the substation and the first customers served by the feeder – this portion of the feeder is typically referred to as the feeder's exit, or head end. This program will allocate funds towards feeders where these reduced capacity ratings can be readily increased by upgrading the feeder equipment as necessary along the feeder's exit from the substation. The Company has budgeted \$3.0 million in capital additions for the Feeder Exit Capacity program in 2023.

Q. PLEASE DESCRIBE THE PLYMOUTH AREA UPGRADE PROJECT.

A. This project is the result of a joint transmission and distribution engineering study of the area that was finalized in 2016. The project will improve the reliability of the distribution system in the area surrounding the Hollydale substation. It will also ensure the ability of the distribution system to accommodate new load growth in the area by mitigating existing capacity deficiencies and providing needed long-term capacity. The Hollydale Substation project involves expanding the existing Hollydale Substation in Plymouth, Minnesota and installing two new 69-13.8 kV transformers. This project also involves the construction of three new 13.8 kV feeders and other feeder reconfigurations in the area. This project is currently in progress with additional construction work planned for 2021. The project is slated to be in service in 2021, and the total plant additions for this project is $11.8 million.

Q. PLEASE DESCRIBE THE WILSON SUBSTATION PROJECT.

A. This project is needed to mitigate multiple feeder overloads and N-1 contingencies in the area near existing Wilson Substation in Bloomington. These overloads and contingency conditions are the result of steady load growth in recent years the area served by the Wilson Substation. If these issues are not addressed, an increased risk of equipment failures and long duration outages could occur in the area. By resolving these issues, we will be able to provide reliable service to our customers as the load in this area continues to grow. The Wilson Substation project involves the installation of a fourth transformer, construction of three new distribution feeders, new manholes, and a new duct line. Substation and transmission equipment within the Wilson substation will also be upgraded as a part of the project. Construction for the Wilson

Substation Project began in the first quarter of 2018 and is slated to be in service in 2022 with total plant additions of $24.8 million.

Q. PLEASE DESCRIBE THE RAPTOR SUBSTATION PROJECT.

A. The Raptor Substation Project is needed due to the growing load in the Woodbury area that is leading to the risk of potential outages due to 15 MVA risks on both transformers at the Woodbury substation and several large feeder risks. The Raptor Substation Project involves the construction of a new substation in the greater Woodbury area with one 70 MVA transformer and two new 34.5 kV and 34 MVA distribution feeders. This new substation will allow us to continue providing reliable service to our customers while also providing additional capacity for continued community growth. The Raptor Substation Project is currently in progress under construction and the remaining portions of this project is slated to be in-service in 2021 with total plant additions of $7.7 million.

Q. DESCRIBE THE STOCKYARDS SUBSTATION PROJECT.

A. This project is needed to mitigate overloads on one of the transformers and multiple feeders at the existing 115/13.8 kV Stockyards Substation located in South St. Paul, Minnesota. The Stockyards Substation Project involves the installation of a new 47 MVA 115/13.8 kV transformer in the Stockyards Substation and a new 1.5 mile 13.8 kV feeder. This project will be placed in service in 2023 with total plant additions of $8.2 million.

Q. DESCRIBE THE HYLAND LAKE SUBSTATION PROJECT.

A. This project is needed to mitigate two transformer contingency risks and two feeder risks at the existing 115/13.8 kV Hyland Lake Substation located in

Bloomington, Minnesota. The project will also provide additional capacity to serve growing load in the area. The Hyland Lake Project involves the installation of a new 50 MVA 115/13.8 kV transformer in the substation and a new 1.5 mile 13.8 kV feeder. The transformer portion of the Hyland Lake Project is planned to be in service in 2022 and the feeder construction will be complete and placed in service in 2022. This project will be placed in service in 2022, and the total plant additions for this project is $5.0 million.

Q. PLEASE DESCRIBE THE ELM CREEK SUBSTATION PROJECT.

A. This project is needed to mitigate overloads on one of the transformers at the existing 115/34.5 kV Elm Creek Substation located in Maple Grove, Minnesota. The project will also provide additional capacity to serve growing load in this area. The Elm Creek Substation Project involves the installation of a new 115/34.5 kV transformer in the Elm Creek Substation and a new 1.9 mile 34.5 kV feeder. The transformer portion of the Elm Creek Project is planned to be in service in 2021, and the feeder construction will be complete and placed in service in 2022. The total plant additions for the Elm Creek Project is $7.9 million.

Q. PLEASE DESCRIBE THE WESTERN SUBSTATION PROJECT.

A. The Western Substation project is needed to relieve feeder overloads on approximately 11 13.8 kV feeders in the St. Paul area. The Western Substation project involves the installation of a third 115/13.8 kV transformer and one new 13/8kV feeder emanating from the existing Western Substation to alleviate these feeder overload conditions. The Western Substation Project is planned to be in service in 2023, and the total plant additions for this project is $5.4 million.

Q. PLEASE DESCRIBE THE MINNESOTA FEEDER LOAD MONITORING PROJECT.

A. The Feeder Load Monitoring project is a program to install more SCADA (Feeder Load Monitoring) at distribution substations. Our SCADA system provides information to control center operators regarding the state of the system and alerts when system disturbances occur, including outages. This includes control and data of our system, and we frequently refer to the data acquisition portion as Feeder Load Monitoring (FLM). A substation that has SCADA almost always contains both FLM and control. However, there may be substations where we do not have FLM, but we do have control.

Generally, our SCADA collects hourly peak load information at the feeder and substation transformer levels for each substation over an entire year. This information is used as inputs to our Distribution planning process. Ideally we are able to collect all of these data points at each of our substations. However, not all of these data points are available for all substation locations. For internal tracking and reporting purposes, when all three-phase Amps, MW, MVar, and kV are included on all feeders, and two of the following three for the substation transformers (MW, MVar, or MVA) the substation is classified as "Full FLM." If we are missing one or more data points at the substation then the substation is classified as "PartialFLM." If none of these data points are collected at a substation, the substation is classified as "No FLM." Currently, 37 percent of our Minnesota substations qualify as "No FLM," 21 percent qualify as "Partial FLM," and 42 percent qualify as "Full FLM."

The purpose of the Feeder Load Monitoring program is to install SCADA at substations that have partial or no FLM. Given the importance of SCADA capabilities to reliability and load monitoring (for planning and due to increasing levels of DER), in 2016 we embarked on a long-term plan to install SCADA at more distribution substations – calling for installation of SCADA at three to five substations each year. In addition, when we add a new feeder or transformer in a new or existing substation, we equip them with SCADA. The Company has budgeted $11.0 million for the Minnesota Feeder Load Monitoring program over the term of this multi-year rate case ($3.4 million in 2021; $3.8 million in 2022; and $3.8 million in 2023).

4. Mandates

Q. WHAT TYPES OF PROJECTS ARE INCLUDED IN THE MANDATES CATEGORY?

A. These are projects that involve relocating existing utility infrastructure to accommodate public projects such as road widening or realignment.

Q. HOW DO YOU ESTABLISH THE BUDGET FOR MANDATES PROJECTS?

A. Mandate capital addition budgets are developed based on historical trends and known projects. The Company also coordinates with large service territories including Minneapolis and St. Paul to ensure adequate funding for anticipated road work. Mandates tend to trend higher with a favorable economy as cities and counties have additional tax revenues for improvement projects such as road updates.

Table 16 provides a summary of the capital additions budget for Mandate projects for 2021 to 2023.

Table 16

2021-2023 Capital Additions – Mandates

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2021	2022	2023
Mandates	$53.2	$31.2	$34.6

Q. WHY ARE THE CAPITAL ADDITIONS FOR MANDATE PROJECTS GREATER IN 2021 AS COMPARED TO 2022 AND 2023?

A. In 2021, there are two large mandate projects that are required due to road construction projects in the City of Minneapolis – the Fourth Street project and the Hennepin Avenue project. Also in 2021, we will be completing the necessary relocations required for the Southwest Light Rail Transit Project.

Q. PLEASE DESCRIBE THE FOURTH STREET PROJECT.

A. The City of Minneapolis is reconstructing a 0.6 mile segment of Fourth Street between 2nd Avenue and 4th Avenue South. This mandate project involves the relocation of Xcel Energy's existing underground primary and secondary cables, ductlines, and manholes that are in conflict with the modifications to Fourth Street as well as feeder extensions for tying into existing system where necessary and vault top restoration. Vaults provide protection and access to our underground network and during road construction projects, the street and sidewalks elevation change requiring us to rebuild the vault top. The Fourth Street project will be in service in 2021, and the total plant additions for this project is $10.3 million.

Q. PLEASE DESCRIBE THE HENNEPIN AVENUE PROJECT.

A. The City of Minneapolis is reconstructing and realigning a ten-block stretch of Hennepin Avenue between Washington Avenue and 12th Avenue. This mandate project involves the relocation of Xcel Energy's existing underground primary and secondary cables, ductlines, and manholes that are in conflict with the redesign of Hennepin Avenue as well as vault top restoration and feeder extensions for tying into existing system where necessary. The Hennepin Avenue project will be in service in 2021, and the total plant additions for this project is $14.7 million.

Q. DESCRIBE THE SOUTHWEST LIGHT RAIL TRANSIT PROJECT.

A. The Southwest Light Rail Transit project is a light rail project that is being constructed to serve downtown Minneapolis and the communities of St. Louis Park, Hopkins, Minnetonka, and Eden Prairie. This mandate project involves the relocation of Xcel Energy's overhead and underground facilities, manholes, and ductlines that are in conflict with route for this light rail project. The Southwest Light Rail Transit project will be in service in 2021, and the total plant additions for this project is $8.2 million.

5. Tools and Equipment

Q. WHAT IS INCLUDED IN THE BUDGET FOR THE TOOLS AND EQUIPMENT CATEGORY?

A. This category includes various expenditure types required to support our overall operations, including capital tool and equipment purchases. One of the largest drivers in this category over the three year term of this case is equipment purchases necessary for our Feeder Load Monitoring program which adds equipment to our feeders to allow the Company to monitor peak demand. I discussed the Feeder Load Monitoring project above as part of our Capacity investments. Other drivers are investments in our Network Monitoring program, cyber security improvements, and a planned fiber optic build-out that will allow the Company to reduce its dependency on third-party telecommunication providers and improve the reliability, performance, and cyber security of its communication network.

Table 17 provides a summary of the capital additions budget for Tools and Equipment projects for 2021 to 2023.

Table 17

2021-2023 Capital Additions - Tools and Equipment

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2021	2022	2023	Total
Tools and Equipment	$9.4	$11.3	$11.9	**$32.5**

Q. PLEASE DESCRIBE THE NETWORK MONITORING PROGRAM.

A. The Network Monitoring program will enable remote monitoring of the network grids for downtown Minneapolis and St. Paul to ensure continuity of service, assess asset health, and improve operation and maintenance of these assets. The Network Monitoring system is comprised of transceivers and VaultGard devices that monitor and communicate the status of the downtown grid facilities along fiber optic cable installed concurrently with the network conductor. Installation of the Network Monitoring equipment will provide grid visibility and control utilizing real-time data from the downtown distribution networks that will enable the Company to:

- locate faulty equipment more quickly and accurately;

- identify distressed equipment prior to failure;
- identify system deficiencies and manufacturer issues on installed equipment;
- receive instantaneous, real-time email notifications of network events; and
- monitor the system on a real-time basis.

Q. WHAT TYPES OF CYBERSECURITY INVESTMENTS IS DISTRIBUTION PLANNING TO COMPLETE DURING THE TERM OF THIS MULTI-YEAR RATE PLAN?

A. The objective of Distribution's Cybersecurity Program is to ensure compliance and on-going coordination with the corporate Enterprise Security & Emergency Management (ESEM) organization. This involves ensuring the safety and resiliency of the distribution system via the installation, monitoring, and maintenance of automated control equipment which support grid optimization practices supporting overall asset management and incident response planning activities. During this multi-year rate plan, we will be investing in a device management solution to ensure the security of key attributes of automated control equipment on the distribution grid (such as password protection and IP addresses).

Q. DISCUSS THE INVESTMENTS IN FIBER OPTIC BUILDOUT THAT DISTRIBUTION WILL BE MAKING BETWEEN 2021 AND 2023.

A. 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 distribution 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.

As a result, from 2021 to 2023, Distribution will be installing upgraded telecommunication equipment and installing a private communication network path (fiber optic cable) from certain Distribution substation to a leased fiber optic cable that will be solely used only by the Company for communication within our network.

6. AGIS

Q. WHAT IS AGIS?

A. The AGIS initiative is a comprehensive plan that will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers. AGIS provides the foundation for an interactive, intelligent, and efficient grid system that will be even more reliable and better prepared to meet the energy demands of the future. The core components of AGIS are ADMS, AMI, and the FAN. The Company has also undertaken a TOU Pilot program.

Q. WHAT ACTIVITIES WILL THE DISTRIBUTION BUSINESS UNIT PERFORM TO IMPLEMENT AGIS?

A. There are three primary functions that Distribution will perform to implement the AGIS initiative:

- *Installation*: At a high level, Distribution will be responsible for installing and configuring the field devices such as the AMI meters and communications equipment to implement AMI and FAN.
- *Operation*: Distribution will also operate the ADMS and its applications. The Distribution Control Center will be the primary users, with the newly created Grid Management team ensuring its accuracy, availability, and effectiveness. Our Grid Management team will monitor system performance and data integrity to ensure the improvements made to GIS data continue to provide accurate ADMS solutions.
- *Maintenance*: The Distribution Business unit will provide maintenance for the field-based equipment. When possible, maintenance activities such as firmware upgrades will be performed remotely. We note that several types of equipment reside on poles in the "power zone," and require the specialized skills of qualified line workers to access.

Q. DOES THE COMPANY PROPOSE TO RECOVER ANY AGIS COSTS IN THIS RATE CASE FILING?

A. With the exception of internal labor costs, the Company is not seeking recovery of any AGIS costs as part of this rate case. Rather, the Company will seek recovery of these AGIS costs as part of its TCR Rider. The AMI and FAN components of AGIS were recently certified to be included in the Company's TCR Rider in the Commission's July 23, 2020 order accepting the Company's 2019 IDP. ADMS and the TOU Pilot were also previously certified by the

Commission and costs were approved for recovery under the TCR Rider. The Company proposes to continue recovery of the majority of the capital and O&M costs for these projects via the TCR Rider. The only portion of the capital and O&M costs for these projects that will not be recovered in the TCR Rider is the portion attributed to internal labor, which is consistent with the Commission's decision in Docket No. E002/M-12-50. As such, internal labor will be recovered through base rates.

Q. WHAT TYPE OF WORK WILL INTERNAL LABOR BE PERFORMING TO SUPPORT THE IMPLEMENTATION AND OPERATION AND MAINTENANCE OF THESE PROJECTS?

A. Our internal employees will be supporting the implementation of these projects by performing field studies related to the implementation of FAN, assisting with the installation of FAN field devices, performing testing and trouble-shooting of the AMI meters, serving as project managers, and supervising contract employees. In his Direct Testimony, Mr. Halama discusses how internal labor costs for rider capital projects are determined for purposes of base rates.

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

A. While the level of capital investments that Distribution seeks to recover in this rate case are higher than our historical amounts, these investments are reasonable and necessary to ensure the health, safety, and reliability of our distribution system as well as making the necessary investments to advance our distribution system to meet our customers' current and future needs.

IV. O&M BUDGET

A. O&M Overview and Trends

Q. WHAT IS INCLUDED IN THE COMPANY'S DISTRIBUTION O&M BUDGET?

A. The Distribution O&M budget includes costs associated with maintaining, inspecting, installing, and constructing distribution facilities such as poles, wires, transformers, and underground electric facilities. It also includes costs related to vegetation management and damage prevention. Additionally, the Distribution O&M budget includes miscellaneous materials and tools necessary to build, operate, and maintain our electric distribution system and fleet (vehicles, trucks, trailers, etc.). The O&M component of fleet are those expenditures necessary to maintain our existing fleet. This includes annual fuel costs plus the allocation of fleet to O&M based on the proportion of the Distribution fleet utilized for O&M activities as opposed to capital projects.

Q. WHAT ARE THE GENERAL CATEGORIES OF DISTRIBUTION'S O&M BUDGET?

A. Distribution's O&M budget can be broken into six general categories: (1) Internal Labor; (2) Contract Labor; (3) Vegetation Management; (4) Damage Prevention; (5) AGIS; and (6) Other (such as Materials, Fleet, Employee Expenses). I discuss these six categories in further detail below.

Q. WHAT ARE THE LONG-TERM OVERALL TRENDS FOR DISTRIBUTION'S O&M EXPENSES FROM 2017 TO 2020?

A. Distribution's O&M expenditures steadily increased from 2017 to 2019 due to increased expenses related to a larger volume of pole replacements in 2017 and 2019, training related to the new Work and Asset Management (WAM) system, and mutual aid provided to other utilities following storms and hurricanes. I note that while the Company is reimbursed for these mutual aid expenses, these reimbursements are accounted for as revenue and therefore do not get credited to Distribution's O&M budgets.

In addition, our operations in 2020 were impacted by the COVID-19 public health emergency. In response to the impact that COVID-19 had on our communities, customers, and operations in 2020, Distribution adjusted our operations to keep employees and communities safe as well as to maintain financial flexibility as the Company faced uncertainties about the depth and duration of the impacts of COVID-19. Specifically, Distribution temporarily reduced O&M expenses for 2020 by reducing vegetation management activities, holding open positions, and scaling back on overtime and training, whenever possible without impacting safety. I discuss these reductions in detail later in this section.

Q. WHAT ARE THE OVERALL TRENDS FOR DISTRIBUTION'S O&M BUDGETS FOR 2021-2023?

A. During this multi-year rate plan, our Distribution O&M expenses increase in 2021 and 2022, but there is slight a reduction in 2023. The O&M increases in 2021 and 2022 are due to the need to catch up on vegetation management work that was deferred in 2020, and increased costs for damage prevention work (increases in both costs for the contractors that perform this work and the number of locates). Other reasons for these increased O&M expenses in 2021 and 2022 relate to O&M associated with the AGIS initiative and hiring additional internal employees necessary to complete planned Asset Health and Reliability capital projects that will be placed in service in these years.

The reduction in O&M expenses in 2023 is primarily due to a reduction in the AGIS O&M expenses for 2023 due to reduced training and readiness expenses as AMI meter deployment will be well underway by 2023, a reduction in vegetation management funding back to levels more consistent with pre-2020 levels, and expected productivity improvement reductions to that will offset annual labor/non-labor inflation. I discuss our productivity improvements later in my testimony.

Q. WHAT IS ANNUAL LABOR/NON-LABOR INFLATION THAT YOU MENTIONED?

A. Annual labor/non-labor inflation refers to the annual base pay increases for internal labor and annual inflation associated with all non-labor components of our O&M budget. This is estimated as a 2.5 percent annual increase in base pay for bargaining employees and a 3 percent increase for non-bargaining employees. We have also included a 1 percent annual inflationary increase for non-labor O&M expenses.

Q. WHAT IS DISTRIBUTION'S O&M BUDGET FOR 2021, 2022, AND 2023?

A. As shown in Table 18 below, the Distribution O&M budget is $133.1 million in 2021, $139.7 million in 2022, and $134.3 million in 2023. Table 18 also provides a historical look at actual O&M expenditures from 2017 to 2019, as well as forecast O&M expenditures for 2020 (half year actuals and half year forecast) by category. Our O&M actuals, forecast, and budget is also provided in Exhibit___(KAB-1), Schedule 3. It is important to note that while our 2023 O&M expenses are higher than our 2017 O&M expenses, overall, this increase represents a modest 4 percent annual increase from 2017 to 2023.

Table 18

Distribution O&M Expenses[9]

(Dollars in Millions)

NSPM- Electric	2017 Actual	2018 Actual	2019 Actual	2017-2019 Average	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Internal Labor	47.5	50.9	48.3	48.9	47.2	55.1	55.5	56.7
Contract Labor	8.7	10.3	14.1	11.0	8.9	6.8	7.5	9.5
Vegetation Management	31.1	32.4	35.3	32.9	22.9	43.0	46.8	40.9
Damage Prevention	7.3	6.9	7.0	7.1	11.2	12.5	12.9	13.3
AGIS	--	0.9	1.1	0.7	2.2	7.4	8.9	5.9
Other (Materials, Fleet, Employee Expenses, etc.)	13.68	15.33	10.03	13.0	7.38	8.36	8.01	8.0
Total	**$108.3**	**$116.8**	**$115.9**	**$113.7**	**$99.7**	**$133.1**	**$139.7**	**$134.3**

Q. WHAT WERE THE DRIVERS BEHIND THE INCREASE IN O&M EXPENSES BETWEEN 2017 AND 2018?

A. Our 2018 O&M costs increased as compared to 2017 expenses due to NSPM line personnel participating in the large Puerto Rico mutual aid restoration effort. This mutual aid involved Xcel Energy sending employees to Puerto Rico in early 2018 to assist with restoring the power to the island after Hurricane Maria hit in September 2017. The impact of this mutual aid restoration effort was an increase in O&M for 2018 of approximately $4.3 million. While the Company is reimbursed for its expenses incurred in providing this mutual aid,

[9] Includes O&M associated with the Company's AGIS deployment. The Company proposes to recover internal labor costs for AGIS through base rates, with Mr. Halama explaining how internal labor costs are calculated. Other O&M costs for AGIS are not being requested in base rates at this time, as the Company is seeking recovery of these costs through the TCR Rider.

these reimbursements are accounted for as revenue and therefore do not get credited to Distribution's O&M budgets.

Additional increases in 2018 O&M were driven by increased expenses for internal labor (increase of $0.7 million) as new employees were hired to fill key vacancies after Distribution exceeded our attrition goals in 2017 due to greater than anticipated retirements and voluntary departures. Further, O&M in 2018 increased by $2.1 million due to annual labor/non-labor inflation. Finally, $0.8 million of the increase in O&M was due to training related to the implementation of our new WAM accounting system. Training is not budgeted as a specific activity in our O&M budget but shows up as an increase in internal labor expense due to the additional time our employees need to spend in a training environment.

Q. WHAT WERE THE MAJOR DRIVERS BEHIND THE DECREASE IN O&M EXPENSES BETWEEN 2018 AND 2019?

A. Compared to 2018, our 2019 actual O&M expenditures decreased by $0.9 million, or 0.8 percent from 2018 actuals. We were able to reduce 2019 O&M by $4.3 million because the Puerto Rico mutual aid event was limited to 2018. This reduction was partial offset by an increase of $3.1 million for storm restoration in our service territory. The frequency, and in some cases the severity of storms, we experienced in 2019 resulted in storm expenses that were higher than prior years. Specifically, in 2019 a total of 178 storm work orders were issued for storm restoration work in Minnesota compared to only 88 storm work orders issued in 2018, 61 in 2017, and 89 in 2016. This drastic increase in storm work orders in 2019 resulted in higher O&M in our internal labor, contract labor, and other budget categories.

Another contributor to the overall decrease in 2019 was the fact that O&M first set credits came in lower in 2019 as compared to 2018 by $1.2 million and a mixed work adjustment of $5.9 million in 2019.

Q. WHAT ARE "FIRST SET CREDITS"?

A. "First set credits" are O&M labor, transportation, and miscellaneous material credits associated with the installation of meters and line transformers. Because of the way meters and transformers are accounted for (fully installed costs are capitalized upon purchase instead of installation), the actual labor, transportation and miscellaneous materials used to install this equipment is expensed to O&M to avoid accounting for these expenses twice. An equal and opposite credit is then applied upon purchase to offset these actual installation costs that are expensed to O&M.

Q. WHAT IS A MIXED WORK ADJUSTMENT?

A. A mixed work adjustment is used to properly allocate costs between capital and O&M. Distribution made a mixed work adjustment for routine work in two areas: (1) Engineering and Supervision (E&S); and (2) routine pole replacements. In 2019, the Company completed an updated E&S Study that resulted in increased capitalization percentage for our E&S back-office labor for 2019 as compared to previous years. We typically conduct an updated E&S Study every two years to ensure our back-office personnel capital/O&M splits are up-to-date according to the latest work and activities the Distribution Business unit is performing.

A mixed work adjustment was also made for our routine pole replacement work. Routine pole replacements are the standard pole replacements performed by Distribution to replace aging or failing poles across our system. To update the capital and O&M allocation for pole replacements, Distribution performed time-studies in the field for the various activities involved in a pole replacement project (e.g., pole framing, pole installation, equipment installations, etc.). Our Capital Asset Accounting area also has performed a comparison of Xcel Energy capitalization standards to those used by peer utilities to understand how the rest of the industry identifies capital property and activities for pole replacements. The result of both the field time-studies and industry review showed that our current allocation was under allocating costs to capital and over allocating costs to O&M for these pole replacements. As a result, we made an made an appropriate adjustment to O&M.

Q. WERE THERE ANY AREAS OF DISTRIBUTION'S O&M BUDGET THAT INCREASED IN 2019?

A. Yes. Annual labor/non-labor inflation increased O&M expenses by $2.2 million. In addition, vegetation management spending increased $1.7 million over 2018, and employee training for new OSHA Crane Certification as well as Smith Driver Safety Training resulted in an increase in internal labor O&M expenses of $1.0 million.

Q. HOW DOES THE 2020 O&M FORECAST COMPARE WITH 2019 ACTUAL O&M COSTS?

A. The 2020 O&M forecast of $99.7 million is $16.2 million less than 2019 actuals. As I discussed earlier, during 2020, Distribution reduced O&M expenses by

$18.2 million due to COVID-19. These O&M reductions were made in several areas:

- Reduced vegetation management - $11.7 million;
- Reduced labor and overtime - $2.5 million;
- New mixed work adjustment first implemented in 2020 - $1.7 million;
- Reduced training/employee expenses - $1.5 million; and
- Reduced materials expenses - $0.8 million.

Q. WERE THERE OTHER REDUCTIONS TO THE 2020 O&M FORECAST AS COMPARED TO 2019 ACTUALS?

A. Yes. Additional reductions to the 2020 O&M forecast as compared to 2019 are driven by $3.4 million in on-going mixed work adjustment for 2020 and an assumption that storm restoration expenses for 2020 would be in line with the five-year storm average, which resulted in a $4.2 million reduction to O&M. These reductions are partially offset by a $2.7 million increase in annual labor/non-labor inflation, a $4.2 million increase in damage prevention costs, and increased funding for underground cable fault repairs of $750,000.

Q. HOW DOES THE 2021 BUDGET COMPARE WITH 2019 ACTUAL COSTS?

A. The 2021 O&M budget is $133.1 million, an increase of 15 percent compared to 2019 actuals. There are several factors contributing to this increase. The 2021 budget includes $6.1 million in increased funding for vegetation management to perform additional work to catch up with on-cycle performance. As I discussed earlier, the Company made O&M reductions in 2020 due to COVID-19. As a result, Distribution will not complete vegetation management activities on over 1,000 miles of line that was scheduled to be completed in 2020. Distribution plans to make-up for this shortfall by completing additional line miles in both 2021 and 2022. Another component of the increase is related to rate increases for the contract workforce for vegetation management.

The 2021 O&M budget also includes an additional $6.3 million for internal and contract labor necessary to implement the AGIS initiative, which will begin in earnest in 2021 with the start of AMI meter deployment.

Q. WHAT ARE THE OTHER DRIVERS OF THE INCREASE IN O&M BETWEEN 2019 AND 2021?

A. The 2021 O&M budget also includes $4.3 million to support the increase in Asset Health and Reliability capital projects planned for 2021, an increase of $5.5 million in damage prevention, and an increase of $4.6 million for annual labor/non-labor inflation over two years. The increase in damage prevention O&M is due to both contractor rate increases and an increase in the number of locates expected in 2021 which I discuss below.

These budget increases in 2021 are slightly offset by the following reductions: (1) an assumed return to an "average" storm year in 2021 compared to 2019 which was a higher than average year for storms, a reduction of $2.3 million; (2) forecasted mixed work benefits compared to 2019, a reduction of $9.2 million; and (3) a $2.0 million reduction related to productivity improvement efforts.

Q. WHAT ARE THE PRODUCTIVITY IMPROVEMENTS THAT THE COMPANY IS PLANNING TO IMPLEMENT IN 2021 TO REDUCE O&M EXPENSES?

A. An example of these productivity improvements is our centralized scheduling initiative that is expected to be fully implemented in the first quarter of 2021.

Once fully implemented, this centralized scheduling initiative is expected to reap efficiency benefits by allowing the Company to review and schedule capital and O&M workload over entire regions at the NSPM operating company level, ensuring that projects are proactively planned, designed, and resourced well ahead of construction. This is projected to allow the Company to realize efficiency gains at both the design and construction phases of our work, thus reducing overall costs due to false starts and delays. The centralized scheduling concept will also provide a greater ability to share both internal and external resources across various service center offices.

Q. HOW DOES THE 2021 O&M BUDGET COMPARE WITH THE 2020 O&M FORECAST?

A. Distribution's 2021 O&M budget is $33.4 million higher than the 2020 O&M forecast. This is primarily due to the fact that, as noted earlier, the 2020 O&M budget was reduced by $18.2 million in response to COVID-19. These cutbacks were short-term reductions that are not sustainable, and as a result, our 2021 O&M budget restores this $18.2 million in O&M.

Our 2021 O&M budget also reflects the first of two years of incremental vegetation management funding to make-up for work that was not performed in 2020 (due to COVID reductions) and to catch-up to the on-cycle performance schedule. The incremental vegetation management funding amounts to a $5.5 million increase in 2021.

In 2021, our O&M budget also increases by $7.3 million to support the deployment of AGIS and $4.3 million of increased funding necessary to complete a greater number of Asset Health and Reliability Projects. Our 2021

O&M budget is also higher as a result of higher pole replacement volumes as compared to 2020 ($1.7 million increase), a $1.3 million increase in damage prevention, and $2.3 million in annual labor/non-labor annual inflation.

These O&M increases are partially offset by a $6.6 million in reductions related to productivity improvements ($2.2 million), and additional mixed work adjustment benefits ($4.4 million) in 2021.

Q. HOW DOES THE 2023 O&M BUDGET COMPARE WITH THE 2022 BUDGET?

A. The $134.3 million in O&M costs budgeted for 2023 is a decrease of 4 percent or $5.4 million compared to 2022. This decrease reflects the fact that 2022 is the final year of a two-year catch-up increase in O&M funding for vegetation management to make up for the work reductions described above. Our vegetation management budget for 2023 is reflective of our typical year budget for this work. Additionally, AGIS related O&M for 2023 is reduced by $2.8 due to reduced training and readiness expenses as AMI meter and FAN deployment will be well underway by 2023. These reductions are partially offset by $2.4 million in labor/non-labor inflation.

Q. HOW DO THE DISTRIBUTION O&M BUDGETS FOR 2021 TO 2023 COMPARE TO THE THREE-YEAR HISTORICAL AVERAGE FOR 2017 TO 2019?

A. As shown in Table 19 below, Distribution's O&M budget for 2021, 2022, and 2023 averages $135.7 million, while the 2017 to 2019 historical average was $113.7 million.

Table 19

Distribution O&M Actuals and Budget Comparison

(Dollars in Millions)

2017 Actual	2018 Actual	2019 Actual	2017-2019 Average	2021 Budget	2022 Budget	2023 Budget	2021-2023 Average
$108.3	$116.8	$115.9	$113.7	$133.1	139.7	$134.3	$135.7

Q. WHAT IS DRIVING THE INCREASE IN O&M FOR 2021 TO 2023 AS COMPARED TO THE THREE-YEAR HISTORICAL AVERAGE?

A. The major cost drivers for 2021 to 2023 are increased O&M expenses for vegetation management on-cycle recovery funding, AGIS, damage prevention, and incremental O&M to support increased Asset Health and Reliability capital projects over this three-year period. Specifically, these programs introduce an average annual increases as follows:

- Vegetation management post-2020 recovery – average annual incremental increase of $12.1 million;
- AGIS – average annual incremental increase of $7.7 million;
- Damage prevention – average annual incremental increase of $4.8 million; and
- Increase in Asset Health and Reliability capital projects – average annual incremental increase of $4.4 million.

I discuss these drivers in more detail in Section IV(C).

B. Distribution O&M Budget Development and Management

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

A. Our O&M budgeting process takes into account our most recent historical spend in the various areas of Distribution and applies known changes to labor rates and non-labor inflationary factors that would be applicable to the upcoming budget years. We also "normalize" our historical spend for any activities and/or maintenance projects embedded in our most recent history that we would not expect to be repeated in the upcoming budget years (e.g., excessive storm activities or one-time O&M projects). We then couple the normalized historical spend information with a review of the anticipated work volumes for the various O&M programs and activities we perform, factoring in any known and measurable changes expected to take effect in the upcoming budget year. For example, for our major maintenance programs such as cable fault repairs and vegetation management, we review annual expected units/line-miles to be maintained and ensure required O&M dollars are adjusted accordingly.

I note that we also factor in any expected efficiency gains we believe would be captured by operational improvement efforts we continuously are working on within our processes and procedures, along with productivity improvements we would expect to achieve via the implementation or wider application of new technologies. These improvements are already factored into our O&M budgets.

Q. DOES THE ALLOCATION OF DISTRIBUTION O&M FUNDS EVER NEED TO BE CHANGED DURING THE FINANCIAL YEAR?

A. Yes. Given that no year ever transpires exactly as predicted or forecasted, we typically update our O&M expenditure forecasts during the year. As with our capital investments, one of our largest annual sensitivities for O&M expenditures is severe weather. The amount of O&M we spend on weather-related events, such as storm restoration and floods, can vary greatly from one year to the next. In addition, the Distribution business unit will periodically receive a request from the Company to adjust O&M costs within the financial year to account for changes in business conditions in other areas of the Company. When a greater need for expenditures in a particular area is identified, we re-prioritize and reallocate our budgeted O&M dollars toward the goal of operating within our overall O&M budget. However, there are times where circumstances dictate that, in order to maintain safe, reliable service at the levels our customers expect, we will need to spend more than our overall budget would allow to properly address certain items that come about during a given budget year.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION ON HOW SEVERE WEATHER IMPACTS DISTRIBUTION'S O&M EXPENSES EACH YEAR?

A. Our annual O&M expenses are influenced by the magnitude and frequency of significant severe weather and storm restoration activities that occur throughout our service territory. The unpredictable nature of severe weather makes budgeting challenging as there is no such thing as a "typical" year for severe weather. Table 20 below highlights the variability of O&M spending over and above base labor and transportation (i.e., overtime, materials, contractors) for storm restoration events from 2015 to 2019.

Table 20

Annual NSPM O&M Storm Restoration Expenses

(Dollars in Millions)

2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	5-Year Average
$2.60	$2.80	$1.10	$1.90	$6.90	$3.06

As shown in Table 20, the Company experienced significantly higher storm restoration expenses in 2019 compared to our five-year average. This was primarily due to the frequency and, in some cases, the severity of storms we experienced in 2019, as discussed above. Additionally, in 2019 many storms occurred on weekends, which resulted in increased O&M due to overtime rates for certain employees for storm response. Further, the Company cannot predict or budget for extraordinary major storm events. For example, on April 10, 2020 a major storm hit the metro area, and there was widespread damage such that Xcel Energy required storm restoration assistance from other utilities.

Given the inherent variability and unpredictable nature of storm events, our O&M budgets each year consider the most recent five-year storm averages, and the various expenditure categories that include storm restoration activities are budgeted accordingly. The most recent five-year average (2015-2019) for storm restoration expenses for NSPM is $3.1 million.

Q. HOW DOES THE COMPANY MAKE CHANGES TO THE O&M BUDGET DURING THE YEAR?

A. During each year, we routinely monitor our O&M actual expenditures as compared to the budget and identify any significant variances as they materialize. As budget pressures are identified in certain areas or programs, we review options to mitigate those pressures. One mitigation option is to reallocate from other areas of the budget where funds for budgeted work of a lower priority and/or more discretionary nature (in the short-term) to cover the areas or programs experiencing the budget pressures. Such reallocations are considered as long as the amount of funding needed to cover the budget pressure is within a level that can be prudently covered within our overall budget allocation. If the amount of the budget pressure cannot be accommodated via reallocation, such as may be the case in years requiring significant storm restoration activity, we seek approval of adjustments to year-end targeted expenditure levels that would exceed our overall Distribution O&M budget.

Q. PLEASE EXPLAIN HOW THE DISTRIBUTION BUSINESS UNIT MONITORS O&M EXPENDITURES.

A. We monitor our O&M expenditures on a monthly basis. In partnership with our Finance Area, we report out on our monthly and year-to-date actual expenditures versus budgets/forecasts, including deviation explanations for various categories of expenditures. This reporting is provided down to the individual Director management level and in some cases down to individual manager business unit levels as required. Monthly review meetings are conducted at various levels to determine any pressure points and remediation plans that are needed to manage our overall O&M expenditures and ensure proper prioritization of those expenditures.

Q. WHAT STEPS DOES DISTRIBUTION TAKE TO MINIMIZE O&M COSTS?

A. The Distribution business unit takes various steps to minimize the amount of growth in our annual O&M expenditures. We are continuously looking for ways to leverage productivity gains and new technology to become more efficient. Distribution Operations is in the process of reviewing many of our current work processes in a concerted effort to streamline these processes while at the same time enabling a better experience for our customers. One such productivity improvement initiative I previously mentioned is the advancement of our centralized scheduling model for how we plan and schedule much of our capital and O&M work projects and activities. This new model is expected to drive efficiencies on how the work is planned and bundled and thus lowering the costs. These expected reductions are reflected in our current budgets.

C. O&M Budget Detail

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

A. In this section, I describe in detail the components of Distribution's O&M budget. I will describe each component, discuss any changes to O&M for that component over the course of the MYRP, and discuss steps the Company takes to minimize O&M cost growth for that particular O&M budget category.

1. Internal Labor

Q. WHAT IS INCLUDED IN THE INTERNAL LABOR CATEGORY?

A. This category represents the O&M portion of salaries, straight time labor, overtime, and premium time for all Distribution internal 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 activities like employee meetings, training, and administrative functions.

Q. HOW HAVE YOUR O&M COSTS FOR INTERNAL LABOR BEEN TRENDING?

A. Our internal labor costs for the term of the multi-year rate plan are approximately $6 million higher than the most recent three-year average (2017-2019).

Table 21

Internal Labor

(Dollars in Millions)

NSPM-Electric	2017 Actual	2018 Actual	2019 Actual	2017-2019 Average	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Internal Labor	$47.5	$50.9	$48.3	$48.9	$47.2	$55.1	$55.5	$56.7

Q. WHAT ARE THE MAJOR DRIVERS BEHIND THE INCREASE IN INTERNAL LABOR COSTS FROM 2021 TO 2023?

A. The 2021-2023 budgets for internal labor include an annual base pay increases of 3 percent for non-bargaining and 2.5 percent for bargaining employees. The annual base pay increases for our bargaining and non-bargaining employees are discussed in detail in the Direct Testimony of Company witness Ms. Ruth K. Lowenthal.

Another driver of the increase in internal labor costs is Distribution's plan to hire 24 additional bargaining unit employees in 2021. These additional employees are needed to assist with the Asset Health and Reliability projects planned for these years. The additional internal labor costs associated with these new 24 bargaining employees continue in 2022 and 2023.

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE INTERNAL LABOR COSTS.

A. Our centralized scheduling process that I discussed earlier is one way that we are seeking to minimize internal labor costs. Additionally, we have several efforts going on to look at our work processes and determine opportunities to make those processes more efficient thus removing costs. As previously mentioned, our mixed work review processes have also yielded benefits to our internal labor O&M expenditures.

2. Contract Labor

Q. WHAT COSTS ARE INCLUDED IN DISTRIBUTION'S O&M BUDGET FOR CONTRACT LABOR?

A. This category represents our use of contract labor and consultants to perform O&M work on our distribution system. This also includes the delivery services for meters and transformers along with ancillary services such as barricades, flaggers, and restoration. I note that contract labor performs the majority of our vegetation management and damage prevention work but these costs have been broken out into separate categories that I discuss below.

Q. HOW HAVE YOUR O&M COSTS FOR CONTRACT LABOR BEEN TRENDING?

A. Our contract labor costs for 2021 and 2022 are lower than our most recent three-year average (2017-2019) but our 2023 costs are slightly higher. This decrease in contract labor in 2021 and 2022 is due to our plan to add 24 internal employees that will result in a reduction in our contract labor needs in the near term. In 2023, our contract labor costs are expected to slightly increase due to the need for contract labor to assist with the increased number of Asset Health and Reliability projects planned for this year.

Table 22

Contract Labor

(Dollars in Millions)

NSPM-Electric	2017 Actual	2018 Actual	2019 Actual	2017-2019 Average	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Contract Labor	$8.7	$10.3	$14.1	$11.0	$8.9	$6.8	$7.5	$9.5

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE CONTRACT LABOR COSTS.

A. The primary benefit of contract labor is that the Company is able to request competitive bids for these services to obtain well-trained and established work forces specializing in these areas. In addition, by contracting these services, the Company has the flexibility to easily ramp up and ramp down the number of contractors that it needs to respond to different volumes of workloads. To minimize our contract labor costs we partner with our key contract services and material vendors to look for ways to mutually reduce rates by how we structure those contracts and/or identifying opportunities to remove costs through efficiency improvements between our Company and those vendors. As previously mentioned, our mixed work review processes have also yielded benefits to our O&M expenditures for contract labor.

3. Vegetation Management

Q. WHAT IS INCLUDED IN THE VEGETATION MANAGEMENT BUDGET CATEGORY?

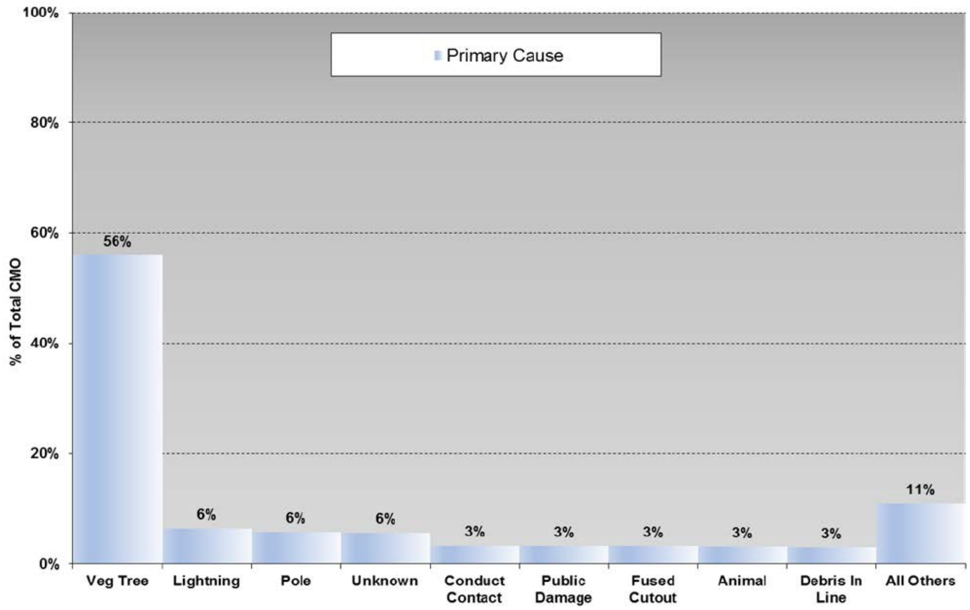
A. Vegetation management expenses are those costs associated with the pruning, removal, mowing, and application of herbicide to trees and tall-growing brush on and adjacent to Xcel Energy's rights-of-way to limit preventable vegetation-related service interruptions. The Company has established a five-year routine maintenance cycle for its distribution facilities, meaning that in general, vegetation around our electric facilities will be maintained every five years.

Q. WHY IS IT IMPORTANT FOR THE COMPANY TO HAVE AN EFFECTIVE VEGETATION MANAGEMENT PROGRAM?

A. An effective vegetation management program is essential to providing reliable service to our customers. Tree-related incidents are among the top two causes for electrical outages on our overhead distribution system. In addition, as shown in Figure 12 below, vegetation-related outages account for the highest percentage of CMO on our overhead system. That said though, our vegetation management program has been successful in that it typically results in 90 percent of the vegetation outages been deemed non-preventable. Being as close as practicable to maintaining 100 percent of all line miles on the established five-year cycle is the best way to ensure that preventable tree-related interruptions are minimized, public and employee safety is addressed, and various regulatory compliance requirements are met.

Figure 12

Overhead Outages by Cause in Minnesota for 2015-2019



Q. HOW DOES THE COMPANY BUDGET FOR ITS VEGETATION MANAGEMENT PROGRAM?

A. The Company budgets for vegetation management based primarily on the number of line-miles of transmission and distribution circuits needing to be maintained on an annual basis in order to maintain 95 percent or better on-cycle performance. To maintain this on-cycle performance, varying miles of circuits come due each year that were last maintained five years previous and need to be maintained again. Annual budgets are prepared based on the line-miles coming due in the given year, the degree of difficulty (degree of forestation) associated with those circuits, and the forecasted vendor contract rates in effort for the given budget year.

Q. WHAT ARE THE MAIN COST DRIVERS FOR THE VEGETATION MANAGEMENT CATEGORY?

A. The main cost drivers in this category are the number of line-miles due for vegetation management in a given year to maintain on-cycle performance, degree of difficulty (forestation) associated with scope of annual circuits due, and finally, the contract labor rates of our primary contractors.

Q. HOW ARE DISTRIBUTION'S VEGETATION MANAGEMENT COSTS TRENDING?

A. From 2017 to 2019 our vegetation management costs increased slightly year over year, primarily due to inflation in the rates charged by our contract workforce. These rates increased due to higher demand for tree trimmers in our industry as a result of wildfire risks. In 2020, as discussed above, budget restrictions due to COVID-19 resulted in a substantial decrease in vegetation management work. This vegetation management funding change is forecasted to result in 1,210 fewer distribution line-miles maintained in 2020 as compared to what was originally planned for 2020.

Table 23
Vegetation Management
(Dollars in Millions)

NSPM-Electric	2017 Actual	2018 Actual	2019 Actual	2017-2019 Average	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Vegetation Management	$31.1	$32.4	$35.3	$32.9	$22.9	$43.0	$46.8	$40.9

Q. WHAT CHANGES IN THE VEGETATION MANAGEMENT BUDGET DO YOU ANTICIPATE FOR 2021 THROUGH 2023?

A. The vegetation management budget is approximately $43.0 million for 2021, $46.8 million for 2022, and $40.9 million for 2023. As previously mentioned, this represents a significant increase for the first two budget years as we attempt the restore our on-cycle performance which was negatively impacted by the vegetation management reductions taken in 2020. The two-year catch-up period will be complete by the end of 2022. Our 2023 funding levels for vegetation management are restored to a level more consistent with actual expenses in 2018 and 2019, with a slight increase due to an increase in the latest multi-year contract agreements with our vegetation management contract service providers.

Q. PLEASE DISCUSS EFFORTS TO MINIMIZE VEGETATION MANAGEMENT COSTS.

A. The Company has taken several steps to minimize cost increases for vegetation management including:

- Bundling the entire volume of work across all operating companies to increase leverage when negotiating pricing with contractors.
- Controlling costs through rigorous negotiations with contractors which includes open-book, transparent pricing methods.
- Using formal contractor evaluation systems (competitive environment) to evaluate contractors against each other based on a set of known and measurable performance measures including cost and quality.
- Performing quality assurance programs such as work completion and contractor crew evaluations.
- Implementing new technologies such as a new scheduling software package implemented by our vegetation management group to better

optimize our Vegetation Management scheduling. This software provides a common system for Company and contract personnel to plan, manage, receive and document completion of work, and track quality assurance inspections. It also aids in managing the activity and cost data associated with the all the work. Through this, the system helps facilitate the most efficient deployment of resources for completion of the work, as well as evaluation of completed work.

4. Damage Prevention

Q. WHAT DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY RELATED TO DAMAGE PREVENTION?

A. In this section of my testimony, I discuss NSPM's damage prevention efforts and the costs associated with locating underground electric facilities and performing other damage prevention activities.

Q. WHAT IS THE DAMAGE PREVENTION PROGRAM?

A. The Damage Prevention program helps excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents. NSPM relies on a combination of internal labor and contractors for the Company's Damage Prevention program.

The primary purpose of this program is to reduce damage to Company-owned buried facilities caused by excavation. Excavation-related damage has the potential to impact public safety and service reliability. This requirement is further supplemented by state law in Minnesota. This program has been designed to ensure compliance with these state and federal regulations and NSPM relies heavily on contractors to perform this work.

Q. ARE UNDERGROUND DAMAGES A SIGNIFICANT RISK TO NSPM'S ELECTRIC SYSTEM?

A. Yes. Whenever excavation and related construction occurs, there is a risk of damage to NSPM's underground electric distribution facilities. As a result, NSPM continues to institute a variety of outreach efforts to excavators regarding the importance of using Gopher State One Call (811) for best excavation practices.

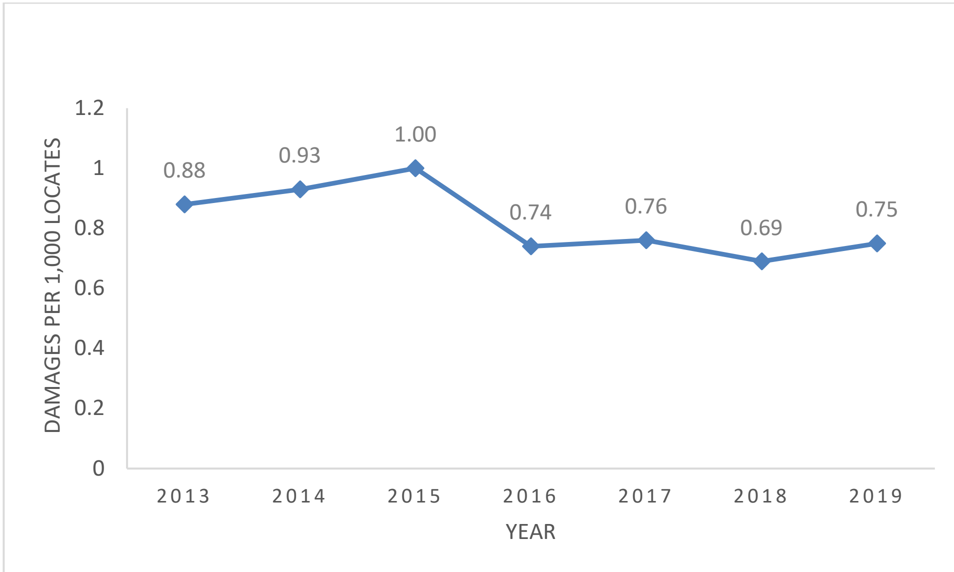
It is also critical that the Company's electric infrastructure is located accurately before excavating to ensure safety for the workers, as well as the public, around the work site. To that end, NSPM continually re-evaluates its damage prevention programs to increase their effectiveness. The Company also provides leadership in several industry organizations where it obtains and shares information about best practices for reducing public damage. We also include best practices and performance requirements in our vendor contracts, in an effort to continually improve and enhance our performance.

Q. HOW IS NSPM PERFORMING WITH RESPECT TO DAMAGE PREVENTION?

A. Figure 13, below, illustrates the number of electric damages per 1,000 locates from 2013 to 2019. As indicated by this figure, the Company has seen almost a 15 percent reduction in damages per 1,000 locates on our system since 2013.

Figure 13

NSPM Electric Damages per 1,000 Locates



Q. HOW ARE LOCATES PERFORMED BY NSPM?

A. The Company is required by law to locate underground facilities when requested. To meet this requirement, the Company is in good standing with Gopher State One Call and utilizes both contracted outside vendors and internal labor to perform locate requests.

Gopher State One Call, formed in response to the legislature's adoption of Minnesota Statutes Chapter 216D, provides a centralized phone center for customers to call to request locates. The cost for this service is free to customers; however, the Company pays Gopher State One Call a cost per ticket.

To respond to tickets resulting from calls to the centralized phone center, the Company utilizes both internal employees and contracts with external contractors to perform locates and provide field support and audit services.

This work is bid out as part of a competitive bid process and the Company selects the best contractor in terms of quality and cost.

Q. HOW DOES THE COMPANY BUDGET FOR DAMAGE PREVENTION?

A. The budget for Damage Prevention is based on several factors: 1) internal labor costs based on approved headcount and labor rates from the collective bargaining process; 2) miscellaneous costs (materials, fleet, other) based on historical actuals; and 3) contract pricing of our Damage Prevention service providers multiplied by the forecasted number of tickets. The Company has forecasted a nominal 1.5 percent annual increase in locate requests for 2021 through 2023. Locates increased by 2.2 percent from 2017 to 2019.

Q. WHAT IS THE CURRENT STATUS OF NSPM'S VENDOR CONTRACTS FOR DAMAGE PREVENTION WORK?

A. NSPM is currently under contract with two vendors until February 1, 2021. The Company issued a request for proposal (RFP) on July 27, 2020 to obtain damage prevention services effective February 1, 2021. Vendors provided a response to our RFP on August 14, 2020. The Company is currently in negotiations with these vendors and expects negotiations to be completed and contracts awarded in November 2020. The Company is expecting an increase in the per unit price for work to be performed from 2021 to 2023 which is consistent with what the industry is seeing across the county.

Q. WHY DOES THE COMPANY UTILIZE CONTRACTORS TO PERFORM UNDERGROUND LOCATES?

A. The Company receives a significant amount of locate requests during the construction season when the ground is free of frost. The Company staffs internal employees to sustain year-round requests and utilizes contractors to supplement locate requests during peak construction periods. During 2019, NSPM performed over 470,000 electric locates and approximately 323,000 or 70 percent of those locates were performed by contractors. Utilizing contractors has historically resulted in lower costs to the Company than hiring additional staff to perform these locates internally.

Q. CAN YOU SUMMARIZE SOME OF THE ISSUES WITH HIRING ADDITIONAL INTERNAL LABOR TO PERFORM MORE OF THE ELECTRIC LOCATES.

A. Yes. First, we would have to staff internally to perform high levels of seasonal work, and ensure we could do so effectively under our collective bargaining agreements. Additionally, our outside vendors assume the risk of inaccuracies with their locates and any resulting damages, whereas using internal labor for that work would increase risk and likely shift damage costs (in the case of inaccurate locates third-party claims or other issues) to the Company.

Q. HAS THE COMPANY ASSESSED WHETHER USING CONTRACTORS PROVIDES APPROPRIATE BENEFITS TO CUSTOMERS?

A. Yes. The Company has performed an analysis comparing the cost per locate for internal labor compared to outside contractors.

Q. BASED ON YOUR ANALYSIS, HOW DOES THE COST OF INTERNAL LABOR PERFORMING LOCATES COMPARE TO CONTRACTORS PERFORMING THE SAME WORK?

A. In 2017, 2018, and 2019, the average cost per locate that required an on-site visit was $17.76 per locate performed by contractors compared to $26.08 per locate for internal employees. I note that our internal labor costs do not include associated fleet costs. However, the cost per locate increases to $29.17 per locate for contractors in 2020 due to a contract pricing change that went into effect February 1, 2020. I note that we receive approximately 80,000 requests a year that do not require an on-site locate visit. Requests that can be completed without a technician visiting the work site are those sites that have overhead electric facilities instead of underground facilities. These requests are completed in the office by our internal employees. These locates are not included in the cost comparison provided above.

Q. WHY WAS THERE AN INCREASE IN VENDOR COSTS ASSOCIATED WITH THE NEW CONTRACT THAT WENT INTO EFFECT FEBRUARY 1, 2020?

A. At the time the contract was negotiated, before the COVID-19 pandemic, the labor market for these jobs was tight. Additionally, the insurance premiums to protect the vendor from damages caused by inaccurate locates performed by their employees increased. Damages caused by vendors mislocating our underground facility is covered by the vendor, which is a major factor in our decision to utilize outside vendors for this type of work.

Q. WHAT WERE THE ACTUAL COSTS ASSOCIATED WITH DAMAGE PREVENTION FROM 2017-2019?

A. Table 24, below, shows the actual O&M costs associated with damage prevention in 2017, 2018, and 2019, as well as the three-year average. Table 24 also contains forecasted damage prevention costs for 2020 and the budgeted costs for 2021 through 2023.

Table 24

Damage Prevention O&M Expenses

(Dollars in Millions)

NSPM-Electric	2017 Actuals	2018 Actuals	2019 Actuals	2017- 2019 3-year Average	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Labor	0.59	0.88	1.33	0.94	1.61	1.88	1.93	1.98
Outside Services	6.41	6.04	5.61	6.02	9.41	10.32	10.67	11.03
Materials and Commodities	0.08	-	0.01	0.03	0.04	0.05	0.05	0.05
Other	0.24	0.01	0.06	0.10	0.12	0.26	0.26	0.26
Total	$7.32	$6.93	$7.01	$7.09	$11.18	$12.52	$12.92	$13.33

Q. PLEASE EXPLAIN THE INCREASE FROM 2019 ACTUALS TO THE 2021 BUDGET FOR DAMAGE PREVENTION.

A. The $12.52 million damage prevention 2021 test year budget includes a $5.5 million increase in damage prevention costs compared to 2019. This increase is attributable to both an increase in the volume of underground locate request and a higher contract cost per locate due to the cost increase that went into effect on February 1, 2020.

Q. CAN YOU EXPLAIN WHY YOU ARE FORECASTING APPROXIMATELY A 2 PERCENT INCREASE IN THE VOLUME OF TICKETS FROM 2019 TO 2021, IN ADDITION TO THE COST PER LOCATE INCREASE YOU ALREADY IDENTIFIED?

A. From 2017 to 2019 the Company saw an 11 percent increase in the number of electric locates. From 2019 to the 2021, the Company is forecasting a 1.9 percent increase with a 1.5 percent annual increase through 2023. As shown in Table 25, below, between 2017 and 2019, we saw an increase of over 10,200 locates.

Table 25

NSPM (Minnesota) Volume of Electric Locates

2017 Actuals	2018 Actuals	2019 Actuals	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
424,483	459,904	470,697	472,666	479,756	486,952	494,256

Q. DOES THE COMPANY PLAN TO CONTINUE USING LOCATE CONTRACTORS DESPITE THE INCREASE IN COSTS ASSOCIATED WITH CONTRACTING FOR THIS WORK?

A. Yes, for the foreseeable future. As mentioned earlier, the Company is currently evaluating RFP results for contract locating services beginning on February 1, 2021. Simultaneously, the Company is in discussions with the union to determine if additional internal resources can replace contract locating services. Even if we determined that it would be appropriate and cost-effective to bring on sufficient internal staff to complete this work internally and were able to do so within the confines of our collective bargaining agreements, it would require significant time to effectuate these changes and hire enough staff to undertake the work. As we continue to gather information from the RFP process and other efforts, the Company will keep the parties informed as appropriate.

5. AGIS

Q. WHAT TYPES OF O&M COSTS IS DISTRIBUTION INCURRING TO IMPLEMENT THE AGIS PROJECTS?

A. Distribution's AGIS related O&M costs include internal labor, contract labor, vendor services, and materials. As I noted above, the majority of the AGIS costs will be recovered through the TCR Rider. The only portion of the AGIS capital and O&M costs that will be recovered through base rates are those costs related to internal labor. I discussed the types of activities that will be performed by internal labor earlier in my testimony. All of the AGIS O&M costs attributed to Distribution are included in the O&M budgets presented here and are discussed in my testimony as they are helpful to understanding to Distribution's overall O&M budget regardless of how they are recovered.

Table 26

AGIS O&M Expenses

(Dollars in Millions)

NSPM-Electric	2017 Actual	2018 Actual	2019 Actual	2017-2019 Average	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
AGIS	--	$0.9	$1.1	$0.7	$2.2	$7.4	$8.9	$5.9

6. Other

Q. WHAT O&M COSTS ARE INCLUDED IN THE OTHER CATEGORY?

A. This category includes Distribution's allocated costs for fleet (vehicles, trucks, trailers, etc.), employee expenses for training and safety meetings, and miscellaneous materials and tools necessary to operate and maintain our electric distribution system.

Q. HOW HAVE YOUR O&M COSTS FOR OTHER BEEN TRENDING?

A. Our Other O&M costs for 2021 to 2023 are lower than our most recent three-year average (2017-2019). This decrease in Other O&M costs is the result of slight decreases in fleet expenses and materials expenses due to the mixed work reductions previously discussed, which has a positive impact on both our O&M transportation and material costs. This decrease is also due to a slight increase in first set credits (which reduce our O&M expenses) in these years.

Table 27

Other O&M Expenses

(Dollars in Millions)

NSPM-Electric	2017 Actual	2018 Actual	2019 Actual	2017-2019 Average	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Other (Materials, Fleet, Employee Expenses, etc.)	$13.68	$15.33	$10.03	$13.0	$7.38	$8.36	$	8.0

Q. WHAT DO YOU CONCLUDE ABOUT DISTRIBUTION'S O&M COSTS OVERALL?

A. Distribution works diligently each year to minimize increases in our O&M costs. However, in certain years we may experience higher than anticipated O&M costs due to increases in number or severity of severe weather events. During the term of the multi-year rate plan, Distribution's O&M costs will be increasing due to increased investment in capital programs, such as AGIS and Asset Health and Reliability projects, which require increased O&M to implement. In addition, our O&M costs for vegetation management are higher during the first two years of the multi-year rate plan as we catch up on work that was delayed in 2020. As a result, our O&M cost levels demonstrate a balance between reasonable and prudent management while enabling implementation of necessary capital investments and volume increases in some of our programmatic work activities.

V. ELECTRIC VEHICLE PROGRAMS

A. Overview of the Electric Vehicle Programs

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

A. In this section, I describe the Company's EV programs and discuss the EV capital and O&M budgets for 2021 to 2023.

Q. WHY IS THE COMPANY INVESTING IN EV PROGRAMS?

A. As a Company, we have a groundbreaking objective to reduce emissions 80 percent below 2005 levels by 2030, with zero emissions by 2050. With an increasing reliance on renewable generation resources and plans to continue to shift to more renewable generation resources, the electricity sector is no longer the leading producer of greenhouse gases in the United States. Instead, the transportation sector now accounts for the greatest percentage of emissions. Our investments in EVs provide an opportunity to build on our Company's utility decarbonization efforts and reduce carbon emissions across both the electricity and transportation sectors. To that end, we have committed to powering 1.5 million EVs across the areas served by Xcel Energy's operating companies by 2030, which is 20 percent of all vehicles and is equivalent to a 30-fold increase in electric vehicles.[10]

The Company has also developed EV programs in response to legislative and Commission directives aimed at decreasing the greenhouse gas emissions in the State.

Q. HOW HAS THE LEGISLATURE ENCOURAGED THE DEVELOPMENT OF EV PROGRAMS?

A. The Minnesota legislature developed statewide greenhouse gas emission goals in Minn. Stat. § 216H.02 that apply to the transportation and electric utility sectors, among others. Additionally, Minn. Stat. § 216B.1614 (EV Statute), which was enacted in 2014, established requirements for utilities to engage in

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[10] *Xcel Energy Electric Vehicle Vision*, XCELENERGY.COM, https://www.xcelenergy.com/staticfiles/xe-responsive/Marketing/EV%20Vision%20Brochure.pdf.

the electrification of the transportation sector. Specifically, the statute states that "each public utility selling electricity at retail must file with the commission a tariff that allows a customer to purchase electricity solely for the purpose of recharging an electric vehicle."[11] The tariff must be available to the residential class. It also authorizes a cost-recovery mechanism to allow utilities to recover costs "reasonably necessary to comply" with the statute, as well as costs related to informing and educating "customers about the financial, energy conservation, and environmental benefits of electric vehicles."[12]

Q. HOW HAS THE COMMISSION ENCOURAGED THE DEVELOPMENT OF EV PROGRAMS?

A. The Commission recognized that the transportation sector now accounts for the greatest percentage of greenhouse gas emissions in Minnesota and has not significantly reduced emissions levels.[13] Increasing the adoption of EVs in Minnesota can help the transportation sector reduce its emissions and the State meet its emissions reduction goals and fight climate change. The Commission has also recognized that utilities are uniquely situated to help drive the electrification of the transportation sector in Minnesota. In furtherance of Minnesota's greenhouse gas emission reduction goals, the Commission ordered utilities to "file proposals, which can be pilots, intended to enhance the availability of or access to charging infrastructure, increase consumer awareness of EV benefits, and/or facilitate managed charging or other mechanisms that optimize the incorporation of EVs into the electric system."[14]

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[11] Minn. Stat. § 216B.1614, subd. 2.
[12] *Id.*
[13] *In re Commission Inquiry into Electric Vehicle Charging and Infrastructure*, Docket No. E999/CI-17-879, ORDER MAKING FINDINGS AND REQUIRING FILINGS (Feb. 1, 2019).
[14] *Id.*

Q. WHAT COMMISSION APPROVALS HAS THE COMPANY RECEIVED REGARDING ITS EV PROGRAMS?

A. In 2015, the Commission approved the Company's Residential EV Charging Tariff,[15] which provides customers who opt to have a dedicated service line and meter installed for their EV charger with the opportunity to charge their EV during off-peak hours at deeply discounted rates.

In May 2018, the Commission approved the Company's Residential EV Service Pilot,[16] which is designed to help customers participate in off-peak rates without the upfront costs of a second service line and provide customers with the option of having the Company install and pay for the upfront costs of charging equipment. The Company applied for and received verbal Commission approval to expand this pilot into a permanent program on May 7, 2020.

In July 2019, the Commission approved the Company's Fleet EV Service and Public Charging Infrastructure Pilots,[17] which are structured to encourage the electrification of fleets and development of public charging facilities by having

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[15] *In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of a Residential Electric Vehicle Charging Tariff*, Docket No. E002/M-15-111, ORDER APPROVING TARIFFS AND REQUIRING FILINGS (June 22, 2015). *See also In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of a Residential Electric Vehicle Charging Tariff*, Docket No. E002/M-15-111, ORDER ACCEPTING 2017 ANNUAL REPORTS AND ESTABLISHING REQUIREMENTS FOR NEXT ANNUAL REPORTS (Nov. 15, 2017); *In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of a Residential Electric Vehicle Charging Tariff*, Docket No. E002/M-15-111, ORDER ACCEPTING ANNUAL REPORTS AND ESTABLISHING REQUIREMENTS FOR NEXT ANNUAL REPORTS (Sept. 11, 2018); *In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of a Residential Electric Vehicle Charging Tariff* Docket No. E002/M-15-111, ORDER ACCEPTING ANNUAL REPORTS AND ESTABLISHING REQUIREMENTS FOR ADDITIONAL FILINGS (Dec. 12, 2019).

[16] *In the Matter of Xcel Energy's Petition for Approval of a Residential Electric-Vehicle Service Pilot Program*, Docket No. E002/M-17-817, ORDER APPROVING PILOT PROGRAM, GRANTING VARIANCE, AND REQUIRING ANNUAL REPORTS (May 9, 2018).

[17] *In the Matter of Xcel Energy's Petition for Approval of Electric Vehicle Pilot Programs*, Docket No. E002/M-18-643, ORDER APPROVING PILOTS WITH MODIFICATIONS, AUTHORIZING DEFERRED ACCOUNTING, AND SETTING REPORTING REQUIREMENTS (July 17, 2019).

the Company build "make ready" infrastructure to support public and fleet customers.

In October 2019,[18] the Commission approved the Company's Residential Subscription Service Pilot, which provides all the services of the Residential EV Service Pilot and also includes a straightforward monthly subscription fee that makes the cost of charging an EV easier to understand.

In May 2020, the Commission voted to approve the Company's EV Home Service program (a permanent expansion of the EV Service Pilot discussed above).[19] This program is designed to make it easier and more affordable for residential customers to access the benefits of charging off-peak.

Q. FOR WHAT EV PROGRAMS IS THE COMPANY SEEKING TO RECOVER ITS COSTS IN THIS RATE CASE?

A. The Company is seeking to recover capital and O&M expenses for 2021 to 2023 associated with the following Commission-approved EV pilots and programs: (1) Residential EV Service Program; (2) Fleet EV Service Pilot; (3) Public Charging Infrastructure Pilot; (4) Residential EV Subscription Service Pilot; and (5) EV Home Service Program.

The Company is also seeking to recover capital and O&M expenses for 2021 to 2023 associated with new offerings highlighted in the Transportation Electrification Plan, and for which the Company plans to seek Commission

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[18] *In the Matter of Xcel Energy's Petition for Approval of a Residential EV Subscription Service Pilot Program*, Docket No. E002/M-19-186, ORDER APPROVING PILOT WITH MODIFICATIONS, AND SETTING REPORTING REQUIREMENTS (Oct. 7, 2019).

[19] *See* Docket No. E002/M-19-559.

approval during the term of this multi-year rate plan: (1) Multi-Dwelling Unit Charging Offering; (2) Electric School Bus Offering; (3) a Customer-provided (Bring-Your-Own) Charging Offering.

Q. DOES THE DISTRIBUTION AREA BUDGET INCLUDE ALL OF THE EV PROGRAM COSTS?

A. No, but the Distribution budget does include the majority of the EV program costs. This includes all of the capital costs, along with the O&M expenses related to the EV equipment installations and maintenance. I support these costs for the MYRP period as part of my testimony.

Other EV program O&M costs for the MYRP period are included in the Customer and Innovation business area budget. These costs are related to program management, IT, program evaluation, stakeholder groups, awareness, education, and outreach. For convenience, I have included high-level discussion of these costs in my testimony.

Finally, the EV program deferred O&M and depreciation expense for prior years are discussed in the testimony of Mr. Halama.

Q. WHAT ARE DISTRIBUTION'S OVERALL CAPITAL AND O&M COSTS FOR THESE EV PILOTS AND PROGRAMS OVER THE TERM OF THIS MULTI-YEAR RATE CASE?

A. Tables 28 and 29 below provide the capital additions and related O&M expense budgets for the Company's EV programs that are included in this rate request.

Table 28

Overall EV Program Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2021 Budget	2022 Budget	2023 Budget
Capital Additions	$11.7	$10.9	$12.2

Table 29

Overall EV Program Distribution O&M Expenses

(Dollars in Millions)

NSPM – Total Company Electric (Dollars in Millions)	2021 Budget	2022 Budget	2023 Budget
O&M Expenses	$1.0	$0.8	$0.9

B. Commission-Approved EV Programs

1. Residential EV Programs

Q. PLEASE DESCRIBE THE RESIDENTIAL EV SERVICE PILOT.

A. The Company launched the Residential EV Service Pilot in August 2018 to study the effectiveness of offering residential customers a home charging product without the need to install a second meter. The pilot lowered potential barriers to EV ownership and participation in time-varying rates by reducing customers' upfront costs related to charging equipment installation and the installation of a second meter. Through the pilot, the Company coordinated the installation of level 2 electric vehicle charging equipment at a customer's home to facilitate faster, convenient EV charging. The charging equipment provides billing quality energy usage data. This allows participating customers to take service under a TOU energy rate that incentivizes participants to schedule their charging during off-peak periods.

Q. PLEASE DESCRIBE THE RESIDENTIAL EV SUBSCRIPTION SERVICE PILOT.

A. This pilot is based on much of the structure of the Residential EV Service Pilot. The pilot will allow customers to charge off-peak for a preset monthly fee. This will encourage off-peak charging and offer customers certainty in monthly charging costs. Similar to the Residential EV Service Pilot, Company-provided equipment will be used to measure charging. Enrollment in the pilot is capped at 150 participants. As of September 28, 2020, we have 108 customers who are enrolled in the program.

Q. PLEASE DESCRIBE THE EV HOME SERVICE PROGRAM.

A. Due to the immediate interest in our Residential EV Service Pilot, the Company quickly developed a plan to expand the pilot into a permanent offering – the EV Home Service Program. This proposal built off the learnings from the pilot to deliver a program that can deliver the benefits to many more residential participants. The Company filed for Commission approval of EV Home Service, in August 2019. The Commission verbally approved the program during their May 7, 2020 agenda meeting. We expect to launch this permanent program in January 2021, and all customers currently in the Residential EV Service Pilot would be transitioned to the permanent offering at that time. As such, all costs in the MYRP years are budgeted under the permanent offering.

Q. WHAT ARE THE BENEFITS OF THE COMPANY'S RESIDENTIAL EV OFFERINGS?

A. There are several benefits of the Company's Residential EV offerings which include, (1) reducing the initial barriers of entry inherent in EV charging rate adoption, (2) improving customers' experiences with EV charging; (3) increase interest and awareness around EVs leading to higher adoption rates for EVs; (4) ensure safe and reliable service consistent with our standards through the provision of a tailored EV service platform.

Q. WHAT ARE THE CAPITAL COSTS FOR THESE RESIDENTIAL EV OFFERINGS THAT ARE INCLUDED IN THE COMPANY'S RATE REQUEST?

A. Capital investments for the residential EV offerings are for the purchase and installation of the charging equipment. Each residential program offers customers a choice of chargers from a pre-approved list. The Company then coordinates installation charging equipment using contractors selected through a competitive process. The capital additions for each year of the MYRP term are provided in Table 30 below.

Table 30
EV Residential Pilots and Programs
Capital Additions

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2021 Budget	2022 Budget	2023 Budget
EV Residential Capital Additions	$0.5	$0.8	$1.3

Q. HOW WAS THE CAPITAL BUDGET DEVELOPED FOR THE EV RESIDENTIAL PILOTS AND PROGRAMS?

A. The capital budget is based on the number of customers allowed in each pilot as well as our experience with the initial EV Residential Service Pilot and level of interest in these offerings. Budget amounts were determined based on the approved charging equipment, where vendors were selected as a result of extensive testing and selection work completed for our Residential EV Service Pilot. The two installation contractors now used by the Company were selected through a request for proposal process for our Residential EV Service Pilot. As participation grows under the EV Subscription Service Pilot or the permanent EV Home Service Program, the Company will identify additional electricians through a similar competitive selection to facilitate the installation process throughout our service territory.

Q. WHAT ARE THE O&M EXPENSES ASSOCIATED WITH THE EV RESIDENTIAL PILOTS AND PROGRAMS?

A. O&M costs associated with installation of the charging equipment include maintenance of infrastructure and equipment and charging network costs. The Distribution O&M expenses for each year of the MYRP term are provided in Table 31 below.

Table 31

EV Residential Pilots and Programs Distribution O&M Expenses

(Dollars in Millions)

State of MN Electric Jurisdiction	2021 Budget	2022 Budget	2023 Budget
EV Residential O&M Expenses	$0.03	$0.04	$0.04

Q. HOW WAS THE DISTRIBUTION O&M BUDGET DEVELOPED FOR THE EV RESIDENTIAL PILOTS AND PROGRAMS?

A. The Distribution O&M budget is based on the number of customers allowed in each pilot as well as our operating experience with the initial EV Residential Service Pilot and level of interest in these offerings. Budget amounts were determined based on the approved charging equipment network costs as well as hourly rates for contracted electricians to perform maintenance.

2. *Fleet EV Service Pilot*

Q. PLEASE DESCRIBE THE FLEET EV SERVICE PILOT.

A. The Commission approved the Fleet EV Service Pilot in its July 17, 2019 Order in Docket No. E002/M-18-643. Through the Fleet EV Service Pilot, the Company will install, own, and maintain EV infrastructure for non-residential customers operating fleets, focusing on serving the charging needs of light-duty vehicles and buses. In addition, if requested by a customer, the Company would install, own, and maintain the charging equipment itself. This pilot is designed to study Company investment in installing and maintaining EV infrastructure for fleet operators and how reducing upfront costs impacts EV adoption. The pilot also will study the costs and impacts of charging behavior and utilization under time-of-use rates, and the impact of advisory services on fleet conversion. The pilot term is three years, with customer enrollment occurring for up to three years after the pilot launch date, or until the overall pilot funding limit is reached. The pilot was launched with one initial partner, Metro Transit. We expect to add further partners soon, including the Minnesota Department of Administration and the City of Minneapolis.

Q. WHAT ARE THE BENEFITS OF THE FLEET EV SERVICE PILOT?

A. The Company proposed the fleet market for piloting new services for transportation electrification because of:

- The diversity of vehicles – the fleet EV pilot creates opportunities to learn more about the challenges involved in electrifying a variety of vehicle types;

- Value focus – motivated more by project economics and life-cycle costs than residential customers, fleet operators will be more likely to quickly convert significant portions of their fleets to EVs once the business case is established;
- Motivation to reduce greenhouse gas emissions and improve air quality – fleet operators have been first movers in utilizing EVs for environmental and economic reasons, and will be likely to convert their fleets to EVs more rapidly with pilot program support; and
- The volume of vehicles to enable larger strides toward transportation electrification – many of the Company's customers have fleets of hundreds or thousands of vehicles and may be swayed to electrify their fleets by the pilot's improved economics and support for first-movers.

The pilot program will initially help address some of the barriers to EV adoption in the fleet market. It will also allow a deeper understanding of the EV system benefits and how to best socialize costs, especially in the fleet market, and will provide a platform for the Company to evaluate models for offering EV services at scale as the market matures and grows. The information learned through the pilot will also be available to help the Commission, other utilities, and stakeholders consider other EV offerings and program designs in Minnesota.

Q. WHAT CAPITAL INVESTMENTS ARE INCLUDED IN THE FLEET EV SERVICE PILOT BUDGET?

A. Fleet EV Service Pilot capital expenses fall into two categories: EV service connection infrastructure and EV supply infrastructure. Service connection infrastructure covers all equipment on the utility's side of the traditional point of connection, which includes necessary transformer upgrades, pads, poles, new service conductors, as well as metering equipment for EV charging separate from any existing service at the site. Supply infrastructure includes new panels, conduit, and wiring up to the charger (EV supply infrastructure) and the charging equipment as well as any necessary civil construction work in compliance with state and local codes. The capital additions for each year of the multi-year rate plan term are provided in Table 32 below.

Table 32
EV Fleet Capital Additions
(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
EV Fleet Capital Additions	$2.1	$5.3	$3.7	$5.2

Q. HOW WAS THE CAPITAL BUDGET DEVELOPED FOR THE FLEET EV SERVICE PILOT?

A. In the development of these capital budgets, we relied on several sources, including third-party estimators for a limited number of sites, internal subject matter experts to estimate distribution costs in various scenarios, and a third-party consultant to help benchmark our numbers by identifying and sharing studies focused on EV charging infrastructure costs and utility proposals and reports.

Q. ARE THERE O&M EXPENSES ASSOCIATED WITH THE FLEET EV SERVICE PILOT?

A. Yes. The O&M expenses for the Fleet EV Service Pilot fall into the following categories: advisory, analytics, and outreach services; installation management;

program management; and IT. There are also O&M expenses related to the maintenance of infrastructure and equipment, and charging network costs.

Q. WHICH OF THOSE O&M EXPENSES ARE INCLUDED IN THE DISTRIBUTION O&M BUDGET FOR THE FLEET EV SERVICE PILOT?

A. O&M expenses related to installation management, maintenance of infrastructure and equipment, and charging network costs are included in the Distribution budget. The Distribution O&M expenses for each year of the MYRP term are provided in Table 33 below.

Table 33
EV Fleet Distribution O&M Expenses
(Dollars in Millions)

State of MN Electric Jurisdiction	2021 Budget	2022 Budget	2023 Budget
EV Fleet O&M Expenses	$0.6	$0.3	$0.4

Q. HOW WAS THE DISTRIBUTION O&M BUDGET FOR THE FLEET EV SERVICE PILOT DEVELOPED?

A. The Distribution O&M budget is based on the number of partners expected to enroll in this pilot as well as our initial work with Metro Transit prior to pilot launch. Budget amounts were determined based on the approved charging equipment network costs as well as hourly rates for contracted electricians to perform maintenance.

Q. HOW DOES THIS BUDGET COMPARE TO THE BUDGET PROVIDED TO THE COMMISSION IN DOCKET NO. E002/M-18-643?

A. The budget for the Fleet EV Service Pilot remains the same, with implementation over a three-year period, which would end mid-2022. Beyond that, our budget assumes the Company will continue to support fleets electrification beyond the pilot period. The future permanent fleet offering will need to be developed based upon learnings from the pilot, and approved by the Commission prior to launch.

3. Public Charging Pilot

Q. DESCRIBE THE PUBLIC CHARGING PILOT.

A. The Commission approved the Public Charging Pilot in its July 17, 2019 Order in Docket No. E002/M-18-643. Through the Public Charging Pilot, Xcel Energy will install, own, and maintain EV charging infrastructure for developers of public direct current fast-charging stations within the Company's service territory. Unlike the Fleet EV Service Pilot, the Company would not own or maintain any charging equipment. In addition, the Company will partner with the cities of Saint Paul and Minneapolis to support installation of community mobility hubs, for which the cities have selected HOURCAR as the anchor tenant. The cities have obtained Federal Congestion Mitigation Air Quality funds to purchase vehicles, chargers, and operating services for this new mobility service. These charging hubs may be utilized by car-sharing services, transportation network companies (e.g., Uber and Lyft), and the public, including customers who do not have EV charging capabilities at home. The Company is continuing to recruit customers and work with partners at the cities of Minneapolis and Saint Paul to identify potential charging sites. The Company estimates that this pilot will facilitate the installation of approximately 350 charging ports.

Q. WHAT ARE THE BENEFITS OF THE PUBLIC CHARGING PILOT?

A. This pilot program will seek to leverage private and public funding, including Minnesota's Diesel Replacement Program funded by the Volkswagen Environmental Mitigation Settlement and administered by the Minnesota Pollution Control Agency, and help reduce a significant barrier to EV adoption—limited availability of public charging for EVs—by adding public EV charging stations along corridors and at charging hubs. The public charging stations will support longer distance driving, address range anxiety, and provide charging solutions for those who are not able to charge at home. This should encourage greater adoption of EVs within the state, which will reduce greenhouse gases and improve air quality.

Q. WHAT CAPITAL INVESTMENTS ARE INCLUDED IN THE PUBLIC CHARGING BUDGET?

A. Public Charging Pilot capital expenses fall into two categories: EV service connection infrastructure and EV supply infrastructure. Service connection infrastructure covers all equipment on the utility's traditional side of the point of connection, which includes necessary transformer upgrades, pads, poles, new service conductors, as well as metering equipment for EV charging separate from any existing service at the site. Supply infrastructure includes new panels, conduit, and wiring up to the charger as well as any necessary civil construction work in compliance with state and local codes. For the public charging pilot, site hosts and developers are responsible for the procurement, installation, and maintenance of charging equipment. The capital additions for each year of the multi-year rate plan are provided in Table 34 below.

Table 34

Public Charging Capital Additions

(Dollars in Millions)

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2021 Budget	2022 Budget	2023 Budget
Public Charging Capital Additions	$4.1	$5.3	$5.2

Q. HOW WAS THE CAPITAL BUDGET DEVELOPED FOR THE PUBLIC CHARGING PILOT?

A. Similar to the Fleet EV service pilot, we relied on several sources, including third-party estimators for a limited number of sites, internal subject matter experts to estimate distribution costs in various scenarios, and relied on a third-party consultant (Atlas Public Policy) to help benchmark our numbers by identifying and sharing other EV infrastructure studies and utility proposals and reports.

Q. ARE THERE O&M EXPENSES ASSOCIATED WITH THE PUBLIC CHARGING PILOT?

A. The O&M expenses for the Public Charging Pilot fall into the following categories: installation management, program management, and IT. There is additional O&M expenses related to infrastructure maintenance, and marketing, education, and outreach.

Q. WHICH OF THOSE O&M EXPENSES ARE INCLUDED IN THE DISTRIBUTION O&M BUDGET FOR THE PUBLIC CHARGING PILOT?

A. O&M expenses related to installation management and maintenance of infrastructure and equipment are included in the Distribution budget. The Distribution O&M expenses for each year of the MYRP term are provided in Table 35 below.

Table 35
Public Charging Distribution O&M Expenses
(Dollars in Millions)

State of MN Electric Jurisdiction	2021 Budget	2022 Budget	2023 Budget
Public Charging O&M Expenses	$0.4	$0.3	$0.4

Q. HOW WAS THE DISTRIBUTION O&M BUDGET FOR THE PUBLIC CHARGING PILOT DEVELOPED?

A. The Distribution O&M budget is based on the number of sites expected under the pilot as described above. Budget amounts were determined based on internal subject matter experts to estimate distribution costs in various scenarios as well as hourly rates for contracted electricians to perform maintenance.

Q. HOW DOES THIS BUDGET COMPARE TO THE BUDGET PROVIDED TO THE COMMISSION IN DOCKET NO. E002/M-18-643?

A. The Public Charging Pilot budget remains the same, with implementation over a three-year period, which would end mid-2022. Beyond that, our budget assumes the Company will continue to support public charging beyond the pilot period. The future public charging offering will need to be developed based on learnings from the pilot, and approved by the Commission prior to launch.

4. *Additional Components of EV Programs*

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. In this section, I provide a high-level discussion of other components of the Company's approved EV programs that are not included in the Distribution area budgets. O&M costs for these activities are in the Customer and Innovation business area budgets, but I provide this information in my testimony for convenience. These costs are related to program management, IT, program evaluation, stakeholder groups, awareness, education, and outreach.

Costs for EV education and outreach that are incremental to the budget will continue to be included in our established EV cost tracker. Use of the EV tracker is consistent with the EV Statute and based on prior Commission approvals in our separate EV program and pilot dockets, and will be addressed in proceedings for any new offerings. Treatment of the EV tracker costs for prior years is discussed in the testimony of Mr. Halama.

a. *Evaluation and Stakeholder Group for Fleets and Public Charging Pilots*

Q. WHAT EVALUATION AND STAKEHOLDER GROUP ACTIVITIES DOES THE COMPANY PROPOSE FOR THE TERM OF THE MULTI-YEAR RATE PLAN?

A. In order to gather feedback and input from stakeholders, ensure transparency and share lessons learned, as well as to assess our customers' experiences and perceptions about EVs that could lead to increased adoption, we propose to:

- *Host semi-annual advisory group meetings with support from a facilitator.* These meetings are intended to foster discussion about pilot progress, gather ideas for continuing to improve pilots as well as new initiatives, and discuss how the pilots should scale or may be redesigned.

- *Provide data on key metrics in an annual EV compliance report.* Throughout these pilots, we will provide updates on key metrics emphasized in our stakeholder workshops in our annual June 1st EV compliance report.
- *Engage third-party evaluators to conduct an interim and final evaluation.* These evaluations of the pilots will provide information on certain metrics highlighted during our stakeholder workshops such as the customer experience, the impact pilot programs have on customer perceptions of electric vehicles, and impacts on EV adoption.

b. EV Awareness, Education, and Outreach

Q. PLEASE DESCRIBE THE EV AWARENESS, EDUCATION, AND OUTREACH THAT THE COMPANY PROPOSES FOR THE TERM OF THE MULTI-YEAR RATE PLAN.

A. The Company has continually expanded its mass-market electric vehicle advisory efforts. We focus on awareness, outreach, and education. These efforts span multiple communication channels including sponsorship of community events, digital media, and traditional media channels like radio and print, and engagement with trade partners.

Although many customers have general familiarity with EVs, many are not aware of all the facts and benefits of driving electric. Our strategies build EV awareness and promote Xcel Energy's programs through a number of different channels that are convenient and understandable.

EV-related print and updated web content serve as educational pieces for customers that align with our service offerings. The Company also connects directly with customers through community events which enable education through open dialogue. Event presence provides the opportunity to share EV information while gathering feedback and learning more about customer perceptions of EVs. Finally, Xcel Energy has promoted its EV driver options to the auto industry and to electricians who install EV chargers.

One specific example of the Company's expanded advisory efforts for EVs is its development of an online EV advisor tool (EV Advisor) that is designed to be integrated into the Company's website. The EV Advisor has launched and will continue to be refined to provide customers with information on what EV options are best for them and the benefits of EVs.

C. New Programs and Pilots

Q. PLEASE DESCRIBE THE NEW PROGRAMS AND PILOTS IDENTIFIED IN THE 2020 TEP.

A. The Company's 2020 Transportation Electrification Plan (TEP), which was filed on June 1, 2020 in Docket No. E999/CI-17-879, highlighted new programs and pilots in development to support the EV market, including: (1) the Multi-Dwelling Unit Charging Offering; (2) Electric School Bus Offering; (3) a Customer-provided (Bring-Your-Own) Managed Charging Offering; and (4) Metro Transit Additional Infrastructure and Other Fleet Services Offering.

Q. HAS THE COMPANY FILED OTHER EV INVESTMENT PROPOSALS FOR THE MYRP PERIOD IN ADDITION TO THOSE PRESENTED IN THE TEP?

A. Yes. On June 17, 2020, we filed our COVID-19 Relief and Recovery Report in Docket No. E,G999/CI-20-492. This report proposed various investments designed to support economic recovery, including investments in clean energy projects. Specifically, the Company has proposed additional investments to decarbonize the transportation sector through additional support for EVs. We expect these proposals will require additional filings with the Commission in separate dockets, where timing, costs, cost recovery, and any rate mitigation measures will be fully reviewed and determined in those proceedings. As such, costs related to the EV proposals in the Relief and Recovery Report are not included in this current rate case.

Q. WHICH OF THE COMPANY'S PROPOSED NEW EV PROGRAM AND PILOT OFFERINGS ARE INCLUDED THE MYRP BUDGETS?

A. Included in our MYRP request are capital and O&M expenses for 2021 to 2023 associated with three new offerings highlighted in the 2020 TEP: (1) Multi-Dwelling Unit Charging Offering; (2) Electric School Bus Offering; and (3) Customer-provided (Bring-Your-Own) Managed Charging Offering. The Company has already filed its request for approval of a Multi-Dwelling Unit EV Service Pilot and plans to seek approval for the two other offerings during the MYRP period.

Q. PLEASE DESCRIBE THE MULTI-DWELLING UNIT CHARGING OFFERING.

A. The Company filed its request for approval of a Multi-Dwelling Unit (MDU) EV Service Pilot on September 10, 2020, in Docket No. E002/M-20-711. This EV offering focuses on multi-family housing, which presents additional considerations and challenges when compared to the general residential EV service offerings. One goal of this pilot is to generate learnings to inform the appropriate path forward to facilitate growth in this sector as part of our overall portfolio of EV initiatives.

The three primary objectives of the MDU EV Service Pilot are to:

- address the market barriers to installing EV charging at MDUs to increase EV adoption;
- assess the financial support needed to encourage accelerated installation of EV charging in MDUs, and
- provide enough financial support, including by leveraging United States Department of Energy (DOE) funds for carsharing, to facilitate the installation of EV infrastructure in affordable housing MDUs.

Through this pilot, the Company will install supply and charging infrastructure to be used by the residents of MDUs. The pilot is designed with optionality related to parking types and charging equipment ownership that will allow site owners to customize their participation based on their needs. All sites will be required to take electric service on an available time-varying rate, which will further the Company's goal of promoting EV charging at times that make efficient use of the power grip by avoiding system peaks and integrating more renewable energy production.

Q. PLEASE DESCRIBE THE ELECTRIC SCHOOL BUS OFFERING.

A. The Company is investigating an offering to support the use of electric school buses. We believe this type of offering could help drive the market for electric school buses in Minnesota, while potentially piloting charging optimization approaches, including using bus batteries as energy storage resources and minimizing local peak demands – a vehicle-to-grid (V2G) offering. The Company recognizes that the incremental costs for electric school buses are high relative to diesel-powered buses and is exploring opportunities, like rebates, to help reduce these costs. The Company plans to pilot a school bus V2G offering during the MYRP period. We are currently working to determine program viability, including evaluating vendors and discussing opportunities with customers. The Company has proposed rebates for school buses as part of the Relief and Recovery filing discussed above.

Q. PLEASE DESCRIBE THE BRING-YOUR-OWN MANAGED CHARGING OFFERING.

A. The Company plans to propose a new bring-your-own managed charging offering. This offering will focus on charging optimization for residential customers, providing incentives for customers who charge during off-peak time periods. As part of this offering, customers will not be required to use Company-owned equipment, as is the case with our other residential EV offerings, but will be able to participate with qualifying technologies that they would own. The Company has previously proposed this as an option for residential customers in a managed-charging pilot, and the Commission voted to order this new proposal at its May 7, 2020 hearing in Docket No. E002/M-19-559.

Q. YOU ALSO MENTIONED THE 2020 TEP INCLUDED METRO TRANSIT ADDITIONAL INFRASTRUCTURE AND OTHER FLEET SERVICES OFFERINGS. ARE THESE NEW OFFERING INCLUDED IN THE MYRP BUDGET?

A. No. The Company has proposed the additional support for Metro Transit and other transit agencies to support their fleet electrification efforts as part of the Relief and Recovery filing. Metro Transit is considering adding up to 100 buses as well as bus charging to a new bus garage planned for the North Loop area of Minneapolis. The Company has proposed rebates for the buses and charging infrastructure, with review and determinations on those proposals to be conducted in the Relief and Recovery docket rather than in this rate case.

Q. WHAT ARE THE CAPITAL COSTS FOR THESE THREE NEW EV OFFERINGS THAT THE COMPANY IS SEEKING TO RECOVER DURING THE TERM OF THE MULTI-YEAR RATE PLAN?

A. The capital costs for these programs will include the installed costs of charging infrastructure and equipment. The capital additions budgeted for each year of the MYRP term are provided in Table 36 below.

Table 36
New EV Pilots and Programs
Capital Additions

State of MN Electric Jurisdiction Capital Additions (includes AFUDC)	2021 Budget	2022 Budget	2023 Budget
EV New Pilots and Programs Capital Additions	$1.8	$1.1	$0.5

Q. HOW WAS THE CAPITAL BUDGET DEVELOPED FOR THESE NEW EV PILOTS AND PROGRAMS?

A. The Company's budget estimates are based on our experiences with similar pilots, including our EV fleets pilot and DSM offerings, such as smart thermostats.

Q. WHAT ARE THE O&M EXPENSES ASSOCIATED WITH THE NEW EV PILOTS AND PROGRAMS?

A. O&M expenses for these projects include maintenance of infrastructure and equipment and charging network costs. The O&M expenses for each year of the MYRP term are provided in Table 37 below.

Table 37
New EV Pilots and Programs O&M Expenses
(Dollars in Millions)

State of MN Electric Jurisdiction	2021 Budget	2022 Budget	2023 Budget
EV New Pilots and Program O&M Expenses	$0.05	$0.05	$0.05

Q. HOW WAS THE O&M BUDGET DEVELOPED FOR THESE NEW EV PILOTS AND PROGRAMS?

A. The O&M budget uses estimates based on the Company's experience managing similar pilots that provide EV charging infrastructure and seek to optimize load usage, including our EV fleets pilot and DSM offerings such as smart thermostats.

Q. FOR THESE NEW EV PROGRAMS AND PILOTS, DOES THE COMPANY EXPECT ACTUAL COSTS TO EXACTLY MATCH THE MYRP BUDGETED AMOUNTS?

A. No. As discussed earlier in my testimony, actual expenditures may differ from budgeted amounts due to changing circumstances or specific events that occur during a multi-year rate plan period. For these EV proposals in particular, the implementation details, timing, and budgets will require Commission approval in separate dockets, where stakeholder input on the specific programs will also be considered in the Commission's final determinations. As such, actual investments and expenditures may be different than the amounts included in our MYRP budgets in this case.

I also note, for example, that the proposed budget for the MDU pilot included in our September 10, 2020 is higher than what is included in our rate case budget. This is because additional detail was developed for our pilot proposal that was not available at the time our rate case budget was finalized in the summer of 2020. Similarly, as we prepared proposals for our Relief and Recovery filing, we included any rebate portion of the school bus offering as part of that filing, rather than as initially contemplated to go along with the V2G pilot aspect when our rate case budgets were being developed. These changes are indicative of budget variations that may occur as circumstances change over the MYRP period.

Further, with continuing changes in the EV landscape, additional stakeholder input, or as a result of Commission direction, it is possible that the Company may propose additional pilots or offerings during the MYRP period.

Q. HOW DOES THE COMPANY PROPOSE TO MANAGE ANY CHANGES TO ACTUAL EV PROGRAM EXPENDITURES THAT MAY BE REQUIRED DURING THE MYRP PERIOD?

A. As discussed earlier in my testimony, Electric Vehicle Programs is one of the eight capital budget groupings in the Distribution area. Management of any changes to Distribution's capital investments over the course of the MYRP are discussed in Section III.B. Section IV.B. describes how the Distribution business unit – like other business areas of the Company – manages changes to

O&M expenditures that may be required in a particular area by re-prioritizing and reallocating budgeted O&M dollars while still operating within the overall Distribution O&M budget.

VI. LED STREET LIGHTS

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

A. In this section of my testimony I will describe the Company's LED street lighting program and discuss the compliance requirements stemming from the Company's 2015 rate case regarding the reporting of costs and cost savings associated with the conversion to LED street lights.

Q. PLEASE DESCRIBE THE LED STREET LIGHTING PROGRAM.

A. In October 2015, the Company filed a Petition for Approval of a Light Emitting Diode (LED) Streetlight Rate.[20] The purpose of the petition was to introduce an LED rate that would enable the Company to work with its large municipal customers to explore the benefits of converting existing street lights to LED. The goals of the program included: reducing bills; decreasing maintenance and other street light expenses; increasing efficiency; helping to meet energy usage and greenhouse gas emission reduction goals; and improving lighting quality. Although LED fixtures cost more than the existing high pressure sodium (HPS) fixtures, the increased cost was projected to be largely offset by fuel cost savings, maintenance savings and base rate energy and demand cost allocation associated with LED lights.

[20] *In the Matter of a Petition of Northern States Power Company for Approval of a Light Emitting Diode (LED) Streetlight Rate*, Docket No. E002/M-15-920, PETITION (October 15, 2015).

The LED conversion was voluntary, allowing customers to opt out if they desired, and was scheduled to be implemented over a five-year period over the Company's normal relamping schedule. The Company completed the LED conversion in May 2019.

Q. WHAT LED STREET LIGHTING COMPLIANCE REQUIREMENTS ARE YOU ADDRESSING?

A. As part of the Stipulation of Settlement (Settlement) in the last rate case,[21] the Company agreed to remove capital costs associated with the LED conversion project from revenue requirements in that case. Instead, those costs were included in a regulatory asset that was permitted to be deferred until the next rate case. Pursuant to the Settlement, the Suburban Rate Authority and the City of Minneapolis agreed not to contest Xcel Energy's recovery of the deferred LED costs in the next rate case, but reserved the right to review and challenge the actual costs and savings associated with the LED project using the standards applicable to a utility's recovery of a regulatory asset, as well as the class cost of service, revenue apportionment, and other aspects of street lighting rates.

The Settlement directed the Company to "maintain reasonably detailed records of LED costs and cost savings compared to HPS lighting derived from a) relamping of LEDs, b) LED service orders, c) LED effect on base rate energy, and d) demand allocation," and to present this information in the next rate case.[22] I will be addressing a) and b) above, while Mr. Huso will be addressing c) and d).

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[21] *In re The Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-15-826, STIPULATION OF SETTLEMENT at pp. 9-11 (Aug. 16, 2016), and FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATIONS at ¶¶ 103-05 (March 1, 2017).

[22] *In re The Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-15-826, STIPULATION OF SETTLEMENT at pp. 9-11 (Aug. 16, 2016).

Q. PLEASE DESCRIBE THE COSTS OR COST SAVINGS DERIVED FROM ELIMINATING RELAMPING BY CONVERTING TO LED STREET LIGHTS.

A. Historically, the Company conducted proactive relamping of the HPS street lights on a rolling basis, relamping each light approximately every five years. Due to the conversion to LED technology, which does not require relamping, the Company has saved $600,000 per year in relamping costs since 2015. This equates to approximately $3,000,000 million savings to date and the annual savings will continue into the future.

Q. PLEASE DESCRIBE THE COSTS OR COST SAVINGS ASSOCIATED WITH LED SERVICE ORDERS.

A. LED technology lasts significantly longer and requires less maintenance than the replaced HPS street lights. As cobra head street lights were converted to LED from 2016 to 2019, the cost savings associated with fewer service orders for the LED street lights incrementally increased each year. Since the LED conversion was completed in early May 2019, the Company has experienced an 88 percent reduction in street light outages reported for cobra head lights in Minnesota each month. Table 38 provides details on the annual number of street light outages reported from 2015 to 2020 for all Street Light Outages under Rate Code A30 and Table 39 for just cobra head lights under the A30 Rate Code.

Table 38

Street Light Outages – Rate Code A30- Street Lighting System Service (All fixture Types)

Year	Street Light Outages	Percent Reduction	Notes
2015	10,823		Baseline year
2016	10,360	5%	Conversions began in August 2016
2017	7,520	31%	Actuals
2018	5,357	51%	Actuals
2019	3676	65%	Actuals
2020 Projected	3676	67%	Projected

Table 39

Street Light Outages – Rate Code A30- Street Lighting System Service (Cobra Heads Only)

Year	Street Light Outages	Percent Reduction	Notes
2015	10,029		Baseline year
2016	9227	8%	Conversions began in August 2016
2017	6528	35%	
2018	4118	59%	
2019	1986	81%	Conversions completed in May
2020 Projected	1260	88%	Projected

Q. WHAT COST SAVINGS WILL THE COMPANY ACHIEVE DUE TO THE REDUCTION IN SERVICE ORDERS FOR THE LED LIGHTS?

A. Based on the 66 percent reduction in street light outage service calls, the Company estimates that it will save approximately $700,000 in maintenance costs annually.

VII. MINIMUM SYSTEM STUDY AND ZERO INTERCEPT ANALYSIS

Q. WHAT INFORMATION DO YOU PRESENT IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I discuss the data inputs, including sources and assumptions, for the minimum system study and zero intercept analysis. Company witness Mr. Michael A. Peppin provides the study and analysis results in his testimony.

A. Minimum System Study

Q. GENERALLY, HOW DOES THE ENGINEERING ORGANIZATION DETERMINE THE MINIMUM CONDUCTOR, CABLE, TRANSFORMER, AND SECONDARY SERVICE EQUIPMENT BEING INSTALLED ON THE DISTRIBUTION SYSTEM?

A. The minimum-size conductor, cable, transformer, and secondary service equipment used in the Minimum System Study were selected by the Engineering Organization according to its field experience and its evaluation of the smallest practical-sized equipment inventories held in the Company's inventory. The "smallest practical-sized equipment" presently utilized on the Company's distribution system in Minnesota has been developed and refined over a number of decades as our industry has matured and progressed.

Although the equipment analyzed as part of the zero intercept component of the study indicates minimum-size equipment that differs from the minimum-size equipment indicated in Table 40, this does not necessarily represent what is presently utilized on the Company's distribution system in Minnesota. The equipment analyzed for the zero intercept component of the study represents the equipment that currently exists on the Company's distribution system in Minnesota, although much of the equipment has not been installed in several decades. As was described above, the smallest sized equipment presently utilized on the Company's distribution system in Minnesota has been continually developed and refined as the system has matured and progressed.

Q. WHAT IS THE MINIMUM-SIZE EQUIPMENT UTILIZED IN THE MINIMUM SYSTEM STUDY?

A. The Minimum System Study presented by Mr. Peppin utilizes the same minimum-size equipment assumptions as were presented in our last rate case. The only difference is that the new Minimum System Study does not include a minimum-size pole assumption.

For the most recent study, we combined the pole and overhead conductor assumptions because these two components are inextricably linked in installations and are combined on our work orders. The installed costs of the poles are, by nature, included in the installed costs for the overhead conductors, as one would not be installed without the other. Furthermore, the size of the pole installed does not necessarily vary with respect to the load-carrying capacity of the conductor. Rather, the size of the pole is determined by the specific minimum height for clearances, and the strength needed for adequate resiliency to accommodate the weather conditions in the particular geographic area of the installation. As a matter of course, we install the minimum-sized pole that we can for each project based on the clearance and resiliency requirements for that particular geographic area.

Table 40 below provides a summary of the minimum-size equipment utilized in the Minimum System Study.

Table 40

Minimum-Size Equipment from Minimum System Study

Description	Minimum-Size Equipment	FERC Account
OH Conductors – Primary OH Conductors – Secondary	#2 ACSR Bare 1/0 Lashed Aerial Cable	365
UG Cables – Primary UG Cables - Secondary	#1/0 ALUM Stranded #1/0 – 2 – 1/0 600 V	366/367
OH Transformers PAD Transformers	10 kVA 10 kVA	368
OH Secondary Service UG Secondary Service Average Length of Service OH Secondary UG Secondary	#2 Triplex #1/0 – 2 – 1/0 600 V 50 feet 50 feet	369

[1] In the analysis to determine installed costs, the cost of the pole was assumed to be included in the cost of the conductor. Therefore, the pole costs were not individually tracked.

Q. ARE THESE REASONABLE ASSUMPTIONS FOR USE IN THIS CASE?

A. Yes. While there are some differences between the minimum-size equipment currently being installed on the Company's system and the assumptions from Table 40 above, overall, the assumptions reasonably approximate the minimum-size equipment being installed today, or in some cases such as transformers, slightly underestimate the minimum-size equipment.

Q. WHAT FACTORS COULD DRIVE CHANGES TO THE MINIMUM-SIZE EQUIPMENT?

A. Our Engineering Organization monitors equipment performance, changes in the industry, and customer requirements. Each of these factors may result in changes to minimum-size equipment. In addition, as we pursue additional grid modernization improvements or employ new technologies to improve reliability within the distribution system, equipment standard changes may occur.

B. Zero Intercept Analysis

Q. HOW WERE THE SPECIFIC CONDUCTORS, CABLES, TRANSFORMERS AND SECONDARY EQUIPMENT SELECTED TO BE STUDIED IN THE ZERO INTERCEPT ANALYSIS?

A. Unlike the Minimum System Study, the Zero Intercept Analysis is very data-intensive. For this reason, the first step in the Zero Intercept Analysis process was to acquire a set of data for all conductors, cables, transformers and secondary equipment that exist on the Company's distribution system in Minnesota. This was done by querying all of the data available on conductors, cables, transformers and secondary equipment in the Company's Geographic Information System (GIS) database. This data was then split into the following specific Property Units: Overhead (OH) Primary, Underground (UG) Primary, OH Secondary, UG Secondary, OH Transformers and UG Transformers.

These Property Units were then further divided into specific sizes and configurations (i.e. 1/0 AL 3ph under the UG Primary Property Unit). The total length (feet) in the GIS was calculated for each specific configuration of conductors and cables, and the total amount of units in the GIS was calculated for each specific configuration of transformers. Then, the total feet or count for each specific configuration was then divided by the total feet or count for its associated Property Unit to acquire the percent contribution of each specific configuration to the total feet or count of the entire Property Unit on the Company's distribution system in Minnesota (i.e., 1/0 AL 3ph represents 31 percent of all UG Primary feet installed on the Company's distribution system in Minnesota).

The configurations with the highest percent contributions towards the overall feet or unit count of each Property Unit were then selected such that at least 90 percent of the total feet or unit count of the Property Unit was covered by the analysis.

Q. HOW DID YOU DETERMINE THE INSTALLED UNIT COSTS FOR EACH SPECIFIC CONFIGURATION?

A. To acquire the data needed to determine the installed unit costs, data from the GIS was queried on completed Distribution Work Orders. When new equipment such as a cable or a transformer is added to the GIS, or when existing equipment is changed, the equipment is associated with a Work Order number. The Work Order number is an identification number for the specific job that was done to install the equipment. Therefore, when the Work Orders were queried from the GIS, all of the specific equipment installed in those Work Orders was acquired. In the Company's 2015 rate case, Work Orders completed from 2010-2015 were used in the analysis. In the current rate case, the Company supplemented these work orders with ones completed from 2007-2009 (the Company's GIS System was implemented in 2007), and ones completed from 2016-2018.

Then, to determine the costs associated with each Work Order, the Work Orders pulled from GIS were queried in the Company's financial management system. This query was able to pull the total cost for each Work Order, and the breakdown of how much was charged to each cost area (regular labor, overtime labor, equipment, stocked materials, etc.). This then gave a breakdown of historical jobs, what was installed in those jobs, and how much the jobs cost.

Q. WHAT WAS DONE TO REFINE THE DATA USED FOR THE ZERO INTERCEPT ANALYSIS?

A. Using the Work Order and cost data, the Work Orders were then filtered down to those in which only one Property Unit and one specific configuration was installed (i.e., a Work Order that only installs 350 feet of 1/0 AL 3ph would be used for the study, but a Work Order that installs both 350 feet of 1/0 AL 3ph and 200 feet of 750 AL 3ph would be filtered out). This was done to ensure accuracy in calculating the installed unit cost for a single specific configuration because we could not parse out the costs for the two different configurations from the entire cost of a Work Order. Although there could have been ways to approximate installed unit costs based on Work Orders that installed multiple different specific configurations, these approximations would have yielded a less accurate result. Also, while the cost data from the study completed in the last rate case included both new and reconstruction work orders to ensure adequate sample sizes for each configuration, the additional work orders that were added only included new construction work ordered to reduce the variability of the unit costs.

The remaining 11,965 Work Orders were then grouped by the specific configuration that was installed (i.e., a list of all Work Orders in which just 1/0 AL 3ph was installed). This Work Order data was then further refined to eliminate any Work Orders that contained erroneous data (i.e., if no material costs or no labor costs were shown, or if the overtime labor costs were greater than the regular labor costs, etc.). The Company utilized all work orders that were included in the last rate case. For the new work orders that were added in the current case, a similar analysis was undertaken. Additionally, an analysis of the skewness of the data for each configuration was conducted to identify unit cost outliers that should be excluded when calculating the average installed cost for each configuration.

Overall, this process of narrowing down the Work Order dataset eliminated thousands of Work Orders. The identification of the Work Orders that contained erroneous data took considerable time and resources, as each Work Order needed to be analyzed on an individual basis. The ultimate dataset used for the analysis was determined to be an adequate representation of installation costs, containing natural variances in job costs.

Q. HOW WAS THE INSTALLED UNIT COST CALCULATED FROM THE DATA THAT WAS ANALYZED?

A. To calculate the installed unit cost for a specific configuration of a Property Unit, the total cost of all Work Orders associated with that specific configuration was divided by the total feet or units installed. For specific configurations that did not have any reliable Work Order data available, estimations were made using the information from other configurations that did have reliable data available.

Installed unit costs were also acquired for Primary Step-down Transformers. The installed unit costs for Primary Step-down Transformers were used for neither the zero intercept, nor the minimum system components of the study, but were needed to determine the overall plant investment of transformers on the distribution system. Insufficient Work Order data was available to identify unit costs for each step-down transformer in the same way as had been done for other Property Units. Instead, material costs were gathered for each step-down transformer, and the average ratio of material cost to installed unit cost for the corresponding installation type (i.e., 1ph OH, 3ph OH, 1ph UG, 3ph UG) of distribution service transformers were used to estimate the installed unit cost of each step-down transformer. For example, the installed unit cost for a 1ph OH step-down transformer was calculated as its material cost multiplied by the average ratio of installed unit cost to material cost for 1ph OH service transformers. This was done because the scope and cost of labor for these installations are similar, and a significantly greater availability of Work Order data was available for distribution service transformers

Q. FOR THE COST DATA USED IN THE ANALYSIS INCLUDED DATA FROM 2007-2018, WAS ANY ADJUSTMENT MADE TO THE UNIT COST DATA TO ACCOUNT FOR THE DIFFERENT COST VINTAGES OF THE DATA?

A. Yes, the final cost data was normalized to the 2015 vintage year using the Handy Whitman Indices.

Q. HOW DID YOU DETERMINE THE LOAD-CARRYING CAPABILITY FOR EACH COMPONENT STUDIED?

A. With regard to the Zero Intercept Analysis, the load-carrying capability is determined as the unique load-carrying capacity identified for each conductor, cable, transformer, and secondary equipment studied. For transformers, this is measured in kVA. For conductors, cables, and secondary service equipment this is measured in Amps. For three-phase conductors and cables, the load-carrying capacity is defined as three times the ampacity of the single-phase conductor or cable.

Q. HOW WAS THE LOAD-CARRYING CAPABILITY FACTORED INTO THE ANALYSIS?

A. The load-carrying capability was factored into the analysis using the unique load-carrying capacity value for each specific configuration. For transformers, this value was the nameplate kVA value. For conductors, cables and secondary equipment, this value was the ampacity. The values for ampacity of the various conductors, cables and secondary service equipment were acquired from the Company's Distribution design and construction manuals. For three-phase conductors and cables, this ampacity value was calculated as three times the single-phase value listed in the Company's Distribution Design and Construction manuals.

Q. ARE THE ASSUMPTIONS IN THE ZERO INTERCEPT ANALYSIS REASONABLE?

A. Yes. The assumptions and eliminations that were made to the data used for the Zero Intercept Analysis were necessary to ensure accurate results were acquired.

VIII. DISTRIBUTION SYSTEM LOSSES

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

A. In its June 12, 2017 Order from our 2015 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 Class Cost of Service Study.[23] As a result, the Commission directed the Company to report in the next rate case 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

[23] *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).

methods for measuring distribution line losses, while Company witness Mr. Ian R. Benson will discuss the methods for measuring transmission line losses.

Q. WHAT ARE ELECTRIC LOSSES?

A. The Edison Electric Institute (EEI) defines electric losses as the general term applied to energy (kilowatt-hours) and power (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' total peak is reached. There are five categories or distribution subsystems where specific losses occur. Within these categories there may be load and non-load losses, as summarized in the table below. For example, transformers have both load and no-load losses. Load losses are a function of the transformer winding resistance and the load current through the transformer. Transformers and meters also have no-load losses which are a function of voltage.

Table 41

Distribution Subsystems and Losses

Category	Load Losses	No-Load Losses
Distribution Primary Transformers	Yes	Yes
Primary Distribution Lines	Yes	No
Distribution Secondary Transformers	Yes	Yes
Service Lines and Drops	Yes	No
Meters	No	Yes

Q. DOES THE COMPANY HAVE THE CAPABILITIES TO MEASURE ACTUAL LOSSES ON THE DISTRIBUTION SYSTEM?

A. No, not at this time. To measure actual losses on the distribution system, we would need the ability to collect data from locations throughout the distribution system. Specifically, the Company would need the ability to collect energy data at both individual customer premises and from the transformers at each distribution substation. This would allow the Company to evaluate the amount of energy leaving each substation compared to the amount of energy being delivered to the customer. The difference between these two amounts would be used to determine the losses across the distribution system.

Q. WHAT EQUIPMENT WOULD BE NEEDED TO MEASURE ACTUAL LINE LOSSES ON THE DISTRIBUTION SYSTEM?

A. To obtain data at the customer level, AMI meters along with the FAN communication network would need to be installed throughout the system. As I discussed above, the majority of the distribution system is not equipped with

AMI, or any other equipment with similar data collection and communication capabilities.

To collect substation level data, the Company would need Supervisory Control and Data Acquisition (SCADA) technology at each distribution substation. As of November 2019, approximately 102 of the Company's 240 distribution substations in Minnesota have SCADA functionality. Another 50 substations only have partial SCADA. Even those distribution substations that currently have SCADA functionality only have it on the low side of the transformer, and similar equipment would need to be installed on the high side of the transformer to collect the data needed to quantify the losses that occur in the substation transformer.

Q. IS THERE OTHER DATA THAT THE COMPANY NEEDS TO DETERMINE ACTUAL LOSSES ON THE DISTRIBUTION SYSTEM?

A. Yes. In addition to the customer and substation level data, the Company would also need to collect secondary data regarding the transformers and service lines and lengths to perform an accurate line loss analysis. This information would need to be collected manually as it is not currently tracked by the Company in the detail needed for a line loss analysis.

Once all of the customer and distribution station level data is available, the Company would need to develop or purchase software that could take the field data, integrate data from the DER on the system, and calculate the line losses.

Q. DOES THE COMPANY HAVE AN ESTIMATE OF HOW LONG IT WOULD TAKE TO HAVE THE NECESSARY COMPONENTS TO DETERMINE ACTUAL LOSSES ON THE DISTRIBUTION SYSTEM?

A. As noted above, AMI meters and FAN will be installed by the end of 2024. We expect that the installation of the necessary SCADA infrastructure will not be completed until much further in the future, or approximately 15 years from now.

IX. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission approve the Distribution capital investments and O&M budget presented in this rate case. These investments are needed to continue to provide safe and reliable service to our customers while replacing infrastructure that has reached the end of its life, responding to localized areas of demand growth, extending service to new customers, and relocating facilities as needed. To support these capital investments and to maintain our existing assets, our O&M expenditures are reasonable and necessary.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Kelly A. Bloch
Regional Vice President, Distribution Operations
825 Rice Street, St. Paul, Minnesota

Ms. Bloch has more than 29 years of experience in the utility industry where she has compiled a diverse background. She joined Public Service Company of Colorado in 1991 and served in various engineering roles in the four operating companies at Xcel Energy: Manager of Capacity Planning for Xcel Energy, Manager of Distribution Planning for Public Service, Manager of System Planning and Strategy, and Senior Director Electric Distribution Engineering, in addition to her current role.

Ms. Bloch is currently the Regional Vice President, Distribution Operations, for Northern States Power Minnesota and Northern States Power Wisconsin. She is responsible for the electric and natural gas distribution design and construction activities for the Company's service areas in the states of North Dakota, South Dakota, Minnesota, Wisconsin and Michigan.

Resume

Kelly A. Bloch
Regional Vice President, Distribution Operations
825 Rice Street, St. Paul, Minnesota

<u>Education</u>:

Bachelor of Science Electrical Engineering
South Dakota State University

<u>Employment</u>:

Xcel Energy Services

2015-Present	Vice President, Distribution Operations NSPM/WI
2014-2015	Sr. Director, Electric Distribution Engineering
2012-2014	Manager, System Planning and Strategy
2005-2009	Manager, Distribution Capacity Planning
2002-2005	Sr. Engineer, Distribution Capacity Planning

Public Service Company of Colorado

2009-2012	Manager System Planning
1993-2002	Sr. Engineer, Distribution Reliability Assessment
1991-1993	Distribution Standards Engineer

Distribution's Capital Additions: 2021-2023
State of MN Electric Jursidiction
Includes AFUDC

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2021	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023
AGIS	D.0001901.043	AMI-DIST-NSPM-MN Full AMI	7,094,251.35	102,301,010.34	81,030,477.93
AGIS	D.0001900.016	FAN - AGIS - NSPM	6,029,315.87	-	-
AGIS	D.0001907.025	AGIS - Interconnection Portal - MN	-	-	0.00
AGIS	D.0001904.040	IVVO-Comm-Dist Blanket-NSPM	-	-	-
AGIS	D.0001908.064	AGIS-Dist-Cap-ADMS-IVVO-Cont-NSPM	-	-	-
AGIS	D.0001908.038	AGIS-Dist-Capital-Line-AMI-Contin-N	-	-	20,266,765.32
ASSET HEALTH & RELIABILITY	A.0010027.001	MN - URD Cable Replacement Blanket	27,440,000.00	28,910,000.00	28,910,000.00
ASSET HEALTH & RELIABILITY	A.0010019.008	MN - Pole Replacement Blanket	24,903,366.61	23,977,947.71	23,656,278.55
ASSET HEALTH & RELIABILITY	A.0010019.009	MN - Line Asset Health WCF Blanket	16,128,054.67	13,122,586.65	15,124,307.00
ASSET HEALTH & RELIABILITY	A.0010019.001	MN - OH Rebuild Blanket	12,988,175.24	13,629,170.17	14,019,796.89
ASSET HEALTH & RELIABILITY	A.0010019.004	MN - UG Services Renewal Blanket	6,137,639.00	6,701,977.46	6,894,730.40
ASSET HEALTH & RELIABILITY	A.0010019.002	MN - UG Conversion/Rebuild Blanket	4,922,028.37	5,611,233.35	5,772,207.39
ASSET HEALTH & RELIABILITY	A.0010027.002	MN - Feeder Cable Replace Proactive	4,900,000.00	13,720,000.00	14,700,000.00
ASSET HEALTH & RELIABILITY	A.0010077.032	Rebuild Downtown St. Paul Manholes	3,383,613.59	-	-
ASSET HEALTH & RELIABILITY	A.0005521.051	ELR MN Sub Feeder Breakers	3,364,682.69	3,767,224.33	4,589,859.74
ASSET HEALTH & RELIABILITY	A.0010125.024	Reserve Low Impedance Mobile	2,385,987.04	-	-
ASSET HEALTH & RELIABILITY	A.0005521.001	MN Failed Sub Equip Replacement	2,038,014.62	1,860,136.40	1,860,000.11
ASSET HEALTH & RELIABILITY	A.0010077.040	Relocate STP Tunnel Feeders	1,894,866.40	4,277,844.24	4,773,812.80
ASSET HEALTH & RELIABILITY	A.0010125.030	ELR Mobile Substation Renewal	1,871,753.16	4,217,003.13	4,698,145.46
ASSET HEALTH & RELIABILITY	A.0010019.006	MN - UG Street Light Rebuild Blanke	1,796,241.35	1,895,932.81	1,950,672.38
ASSET HEALTH & RELIABILITY	A.0010077.039	SE Region Reliability Initiative	1,419,664.48	2,497,220.78	2,686,779.96
ASSET HEALTH & RELIABILITY	A.0005509.013	ELR STP Vault Tops	1,336,487.87	804,318.26	765,553.57
ASSET HEALTH & RELIABILITY	A.0005521.212	MN Failed Sub TR Replacement	1,321,875.76	1,497,516.03	1,497,756.30
ASSET HEALTH & RELIABILITY	A.0010027.004	MN - FPIP Blanket	980,000.00	980,000.00	980,000.00
ASSET HEALTH & RELIABILITY	A.0010069.004	MN LED Post Top Conversion	945,000.00	945,000.00	945,000.00
ASSET HEALTH & RELIABILITY	A.0010019.005	MN - OH Street Light Rebuild Blanke	908,595.67	914,437.78	940,893.49
ASSET HEALTH & RELIABILITY	A.0010027.003	MN - REMS Blanket	882,000.00	882,000.00	882,000.00
ASSET HEALTH & RELIABILITY	A.0005521.094	ELR MN Sub TRs	850,058.42	2,893,064.67	6,400,591.18
ASSET HEALTH & RELIABILITY	A.0010125.014	ELR MPLS Network Protectors	637,731.18	1,550,439.30	1,394,012.57
ASSET HEALTH & RELIABILITY	A.0005512.008	MPLS UG Network Vault Blanket	473,076.20	473,071.14	473,078.48
ASSET HEALTH & RELIABILITY	A.0005521.091	ELR MN Sub Relays	438,194.18	551,327.31	561,650.41
ASSET HEALTH & RELIABILITY	A.0005521.052	ELR MN Sub Switches	411,022.64	467,972.08	468,048.82
ASSET HEALTH & RELIABILITY	A.0010125.002	ELR MN Sub Batteries	394,622.19	449,253.27	449,326.85
ASSET HEALTH & RELIABILITY	A.0010125.029	T Replace Coon Creek CNC Relays	361,664.51	-	-
ASSET HEALTH & RELIABILITY	A.0005521.103	ELR MN Sub Retirements	340,014.65	374,386.67	374,439.09
ASSET HEALTH & RELIABILITY	A.0005549.020	ELR MN Sub RTUs	322,079.57	388,176.41	391,214.23
ASSET HEALTH & RELIABILITY	A.0005521.093	ELR MN Sub Fences	308,270.96	392,083.41	459,491.69

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2021	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023
ASSET HEALTH & RELIABILITY	A.0010019.003	MN - OH Services Renewal Blanket	273,862.57	235,807.93	242,682.05
ASSET HEALTH & RELIABILITY	A.0005521.092	ELR MN Sub Regulators	246,613.59	313,663.52	367,593.33
ASSET HEALTH & RELIABILITY	A.0005512.012	STP UG Network Vault Blanket	236,540.10	236,537.56	236,541.24
ASSET HEALTH & RELIABILITY	A.0005585.001	MINNESOTA MAJOR STORM RECOVERY	201,443.71	-	-
ASSET HEALTH & RELIABILITY	A.0010019.007	MN - Network Renewal Blanket	113,498.14	247.06	0.53
ASSET HEALTH & RELIABILITY	A.0010125.015	ELR STP Network Protectors	28,035.45	664,008.50	358,499.59
ASSET HEALTH & RELIABILITY	11662320	Tap Cable Injection	0.80	-	-
ASSET HEALTH & RELIABILITY	A.0005518.052	REMS-Maple Grove	0.24	-	-
ASSET HEALTH & RELIABILITY	A.0005509.014	ELR MPLS Vault Tops	(14.11)	1,379,295.27	1,716,235.76
ASSET HEALTH & RELIABILITY	A.0005518.003	NSPM-Poor Perf Fdr Replace Blk	(16.36)	-	-
ASSET HEALTH & RELIABILITY	A.0005508.028	Northwest - Overhead Rebuilds	(22.65)	-	-
ASSET HEALTH & RELIABILITY	A.0005550.005	NSPM-Accelerated URD Cable Rep	(80.14)	(0.05)	-
ASSET HEALTH & RELIABILITY	A.0005550.002	NSPM-Accelerated URD Cable Rep	(147.70)	-	-
ASSET HEALTH & RELIABILITY	A.0010077.024	Rebuild Sacred Heart SCH211	-	4,214,664.71	-
ASSET HEALTH & RELIABILITY	A.0010019.022	MN High Customer Count Taps	-	2,658,000.00	2,658,000.00
ASSET HEALTH & RELIABILITY	A.0010019.024	MN Porcelain Cutouts	-	2,658,000.00	2,658,000.00
ASSET HEALTH & RELIABILITY	A.0005502.015	Serve Essig from Local REA	-	2,135,675.30	-
ASSET HEALTH & RELIABILITY	A.0010077.012	Rebuild Clara City CLC221	-	1,859,841.03	-
ASSET HEALTH & RELIABILITY	A.0010125.005	SUB Convert Clarks Grove CKG 8kV	-	1,615,603.38	-
ASSET HEALTH & RELIABILITY	A.0010077.038	MN Arrestor Replacement Program	-	709,779.41	183,954.50
ASSET HEALTH & RELIABILITY	A.0005521.095	Reserve TR 69/13.8 kV 28 MVA	-	513,047.18	-
ASSET HEALTH & RELIABILITY	A.0010077.002	LINE Convert Clarks Grove CKG 8kV	-	360,221.33	-
ASSET HEALTH & RELIABILITY	A.0010077.011	LINE Convert Sacred Heart SCH Area	-	225,138.33	-
ASSET HEALTH & RELIABILITY	A.0010077.037	LINE Install Lake Yankton LAY061 Ne	-	163,521.58	-
ASSET HEALTH & RELIABILITY	A.0010077.022	T Rebuild West St Cloud to Millwood	-	-	4,876,010.23
ASSET HEALTH & RELIABILITY	A.0010019.019	MN Targeted Undergrounding	-	-	3,780,000.00
ASSET HEALTH & RELIABILITY	A.0010027.006	MN Cable Assessment	-	-	2,940,000.00
ASSET HEALTH & RELIABILITY	A.0001471.001	SUB Reinf Daytons Bluff DBL Sub	-	-	2,685,630.95
ASSET HEALTH & RELIABILITY	A.0010019.018	MN TR and Secondary Replacements	-	-	2,126,400.00
ASSET HEALTH & RELIABILITY	A.0010019.023	MN Pole Fire Mitigation	-	-	1,772,000.00
ASSET HEALTH & RELIABILITY	A.0005521.137	SUB Convert Montevideo MTV 4kV	-	-	1,710,721.90
ASSET HEALTH & RELIABILITY	A.0010019.020	MN Low Cost Reclosers (Single Ph)	-	-	1,240,400.00
ASSET HEALTH & RELIABILITY	A.0010019.021	MN Pole Top Reinforcements	-	-	974,600.00
ASSET HEALTH & RELIABILITY	A.0010077.006	LINE Convert Montevideo MTV 4kV	-	-	720,593.51
CAPACITY	A.0000390.015	SUB Install Wilson WIL TR4 & Feeder	9,267,210.30	-	-
CAPACITY	A.0010148.002	SUB Install Raptor RPO Sub	7,172,426.70	-	-
CAPACITY	A.0000226.009	SUB Plymouth-Area Power Grid Upgrad	5,931,593.38	-	-
CAPACITY	A.0000226.010	LINE Plymouth-Area Power Grid Upgra	4,981,652.55	-	-
CAPACITY	A.0010133.067	Install Hiawatha West HWW TR2	4,891,545.14	-	-
CAPACITY	A.0010101.001	SUB MN Feeder Load Monitoring	3,363,897.79	3,786,071.76	3,786,672.57
CAPACITY	A.0010133.047	SUB Install Elm Creek ECK 34.5kV TR	3,277,402.29	-	-

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2021	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023
CAPACITY	A.0010035.002	MN - UG Reinforcement Blanket	1,895,851.00	1,948,321.00	2,004,751.00
CAPACITY	A.0010133.075	SUB C Reinforce Green Isle TR1 & Fd	1,827,683.77	-	-
CAPACITY	A.0010133.044	Install Midtown MDT TR2	1,811,533.90	-	-
CAPACITY	A.0005503.156	LINE C Install Chemolite CHE065 Fee	1,750,372.31	-	-
CAPACITY	A.0010093.116	C LINE Reinforce Waseca TR2	1,519,727.75	-	-
CAPACITY	A.0010035.004	MN - Line Capacity WCF Blanket	1,431,977.58	1,867,744.93	2,955,531.64
CAPACITY	A.0010093.094	C Install East Bloomington EBL Feed	1,310,960.93	-	-
CAPACITY	A.0005522.033	SUB Reinforce Fair Park FAP TR1 & F	1,269,625.47	-	-
CAPACITY	A.0005522.001	MN Dist Subs Capacity WCF Blanket	904,006.54	1,676,107.66	2,572,176.73
CAPACITY	A.0010035.001	MN - OH Reinforcement Blanket	850,663.00	874,188.00	899,600.00
CAPACITY	A.0010093.086	Reinforce Medicine Lake MEL074	757,953.99	-	-
CAPACITY	A.0005522.279	SUB C Install Chemolite CHE065 Feed	543,456.20	-	-
CAPACITY	A.0010133.085	C SUB Reinforce Waseca TR2	503,102.35	-	-
CAPACITY	A.0010148.003	LINE Install Raptor RPO Sub	502,354.12	-	-
CAPACITY	A.0010093.024	LINE Reinforce Fair Park FAP TR1 &	390,327.32	-	-
CAPACITY	A.0010093.114	C Reinforce Ada ADA081 Feeder	385,202.39	-	-
CAPACITY	A.0010133.077	T Revenue Metering Minnesota Lake	358,231.27	-	-
CAPACITY	A.0010133.076	T Revenue Metering Mapleton	299,433.03	-	-
CAPACITY	A.0010003.007	MN - New Business Network Blanket	276,767.00	284,455.00	292,145.00
CAPACITY	A.0010144.002	Crosstown new 13.8kv Sub(REPLACED)	236,722.58	-	-
CAPACITY	A.0010093.096	LINE C Reinforce Green Isle Fdr	193,024.71	-	-
CAPACITY	A.0010133.080	Reinforce Pine Bend PBE061	152,594.36	-	-
CAPACITY	A.0005522.005	Minnesota-Sub Capac Reinforcem	99,743.20	99,642.60	99,649.10
CAPACITY	A.0010093.106	Install Brooklyn Park BRP071 Switch	29,004.49	-	-
CAPACITY	A.0010093.107	Reinforce Twin Lake TWL072	29,004.49	-	-
CAPACITY	A.0005517.023	Substation Land - MN	110.45	0.08	-
CAPACITY	A.0005502.082	Mntka-Oh Reinforcements	73.08	-	-
CAPACITY	A.0005503.061	Newport-Ug Reinforcements	12.85	-	-
CAPACITY	A.0005502.001	MNOH Reinforcements-MN	0.05	-	-
CAPACITY	A.0005503.063	St Paul-Ug Reinforcements	(82.04)	-	-
CAPACITY	A.0005502.083	Edina-Oh Reinforcements	(200.66)	-	-
CAPACITY	A.0005502.090	St Paul-Oh Reinforcements	(473.99)	-	-
CAPACITY	A.0000390.014	LINE Install Wilson WIL TR4 & Feede	-	14,651,515.04	-
CAPACITY	A.0010093.056	LINE Install Elm Creek ECK 34.5kV T	-	4,629,745.77	-
CAPACITY	A.0010133.073	SUB Install Hyland Lake HYL TR3 & F	-	3,534,857.38	-
CAPACITY	A.0001470.001	SUB Install Salida Crossing 34.5kV	-	2,853,821.59	-
CAPACITY	A.0010133.016	SUB Reinforce Kasson KAN TR1 & Feed	-	2,526,517.53	-
CAPACITY	A.0010093.078	LINE Install Midtown MDT Feeder	-	2,229,875.68	-
CAPACITY	A.0005502.024	LINE Install Wyoming WYO Feeder	-	2,014,295.79	-
CAPACITY	A.0010035.007	MN Community Resiliency	-	1,980,000.00	2,970,000.00
CAPACITY	A.0010093.117	MN EV Grid Improvements	-	1,539,671.91	3,438,899.70

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2021	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023
CAPACITY	A.0010093.084	LINE Install Hyland Lake feeder	-	1,495,304.70	-
CAPACITY	A.0005502.016	LINE Install Feeder Tie Crooked Lak	-	1,141,506.53	-
CAPACITY	A.0010093.074	Reinforce Glenwood GLD Sub Equip	-	701,441.09	-
CAPACITY	A.0010093.108	Extend Woodbury WDY321 for WDY312	-	562,276.44	-
CAPACITY	A.0005522.277	SUB Install Wyoming WYO Feeder	-	503,130.79	-
CAPACITY	A.0010133.070	SUB Install Midtown MDT Feeder	-	503,130.79	-
CAPACITY	A.0010093.104	Install Feeder Tie ALD081-ALD098	-	360,608.37	-
CAPACITY	A.0010093.028	LINE Reinforce Kasson KAN TR1 & Fee	-	336,636.90	-
CAPACITY	A.0010133.082	SUB Reinforce Feeders RAM073 RAM061	-	261,627.99	-
CAPACITY	A.0010093.071	Reinforce Basset Creek BCR062	-	250,514.69	-
CAPACITY	A.0001470.002	LINE Install Salida Crossing 34.5kV	-	192,561.82	-
CAPACITY	A.0010093.017	Install Feeder Tie EBL064	-	150,308.80	-
CAPACITY	A.0010093.079	Install Feeder Tie SOU083 to MDT074	-	100,626.15	-
CAPACITY	A.0010133.006	Upgrade Mound LV bushings and LV CT	-	50,791.00	-
CAPACITY	A.0010133.055	SUB Install Feeder Tie Crooked Lake	-	50,039.47	-
CAPACITY	A.0010093.112	Reinforce Belgrade feeder BEG001	-	47,518.78	-
CAPACITY	A.0000718.003	LINE Install Stockyards STY TR3 & F	-	-	4,511,411.21
CAPACITY	A.0005503.021	Install Baytown BYT Feeders	-	-	4,360,771.60
CAPACITY	A.0010149.001	SUB Install Western WES TR3 & Feede	-	-	4,004,232.38
CAPACITY	A.0000718.004	SUB Install Stockyards STY TR3 & Fe	-	-	3,663,839.82
CAPACITY	A.0010035.008	MN Feeder Exit Capacity	-	-	2,970,000.00
CAPACITY	A.0010133.033	SUB Install Albany ALB TR	-	-	2,847,871.30
CAPACITY	A.0010093.113	LINE Reinforce TSS TR01	-	-	1,837,299.00
CAPACITY	A.0010149.002	LINE Install Western WES TR3 & Feed	-	-	1,403,100.13
CAPACITY	A.0010093.077	Extend Saint Louis Park SLP092	-	-	1,062,834.75
CAPACITY	A.0010133.083	SUB Reinforce TSS TR01	-	-	916,063.35
CAPACITY	A.0010093.048	LINE Install Fiesta City FIC Feeder	-	-	873,542.20
CAPACITY	A.0005517.040	LAND Install Birch Area Sub	-	-	609,470.86
CAPACITY	A.0010093.023	LINE Install Goodview GVW Feeder	-	-	571,565.89
CAPACITY	A.0010133.011	SUB Install Goodview GVW Feeder	-	-	501,107.19
CAPACITY	A.0010133.038	SUB Install Fiesta City FIC Feeder	-	-	501,107.19
CAPACITY	A.0010093.110	Reinforce Shepard SHP062 and SHP071	-	-	274,163.92
CAPACITY	A.0010093.080	Extend Terminal TER064	-	-	160,221.99
CAPACITY	A.0010093.088	Reinforce Saint Louis Park SLP087	-	-	150,970.85
CAPACITY	A.0010093.044	LINE Install Albany ALB TR	-	-	95,665.70
ELECTRIC VEHICLES	A.0010180.005	MN Electric Vehicle Program FLEET	5,305,312.55	3,717,913.92	5,230,961.41
ELECTRIC VEHICLES	A.0010180.006	MN Electric Vehicle Program PUBLIC	4,100,258.95	5,283,621.15	5,230,961.41
ELECTRIC VEHICLES	A.0010180.001	MN Electric Vehicle Program	1,843,645.59	1,080,404.36	446,045.40
ELECTRIC VEHICLES	A.0010180.008	MN Electric Vehicle Program RESIDEN	494,328.34	821,304.20	1,242,096.91
ELECTRIC VEHICLES	A.0010180.007	MN Electric Vehicle Program SUBSCRI	4,093.52	4,092.72	-
FLEET, TOOLS & COMM	A.0006059.511	Tools and Equipment WCF	2,588,509.82	1,725,673.21	862,836.61

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2021	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023
FLEET, TOOLS & COMM	A.0010101.014	NSPM Cybersecurity Measures	1,224,397.96	1,614,242.32	974,809.26
FLEET, TOOLS & COMM	A.0006059.002	MN-Dist Electric Tools and Equip	1,158,788.69	1,158,788.69	1,158,715.55
FLEET, TOOLS & COMM	A.0010101.002	COMM MN Feeder Load Monitoring	967,230.22	1,045,214.72	1,045,349.20
FLEET, TOOLS & COMM	A.0005585.003	NSM - MN CAPITALIZED ELECTRIC LOCA	541,281.65	400,108.25	400,000.09
FLEET, TOOLS & COMM	A.0006059.014	MN-Dist Subs Tools and Equip	520,540.54	496,501.86	496,491.52
FLEET, TOOLS & COMM	A.0010101.013	Install Network Monitoring Mpls	416,564.52	940,856.44	1,050,320.20
FLEET, TOOLS & COMM	A.0010101.012	Install Network Monitoring St. Paul	416,438.85	871,327.64	962,920.75
FLEET, TOOLS & COMM	A.0005553.001	Sub Fiber Communication Cutover	413,788.57	2,431,427.11	4,354,057.66
FLEET, TOOLS & COMM	A.0006059.020	MN-DistLogistics	218,588.04	190,007.89	189,986.00
FLEET, TOOLS & COMM	A.0010148.004	COMM Install Raptor RPO Sub	147,954.66	-	-
FLEET, TOOLS & COMM	A.0000226.022	COMM Plymouth-Area Power Grid Upgra	111,597.28	-	-
FLEET, TOOLS & COMM	A.0010101.007	T Revenue Metering Minnesota Lake	107,622.34	-	-
FLEET, TOOLS & COMM	A.0010101.006	T Revenue Metering Mapleton	107,291.49	-	-
FLEET, TOOLS & COMM	A.0006059.024	MN-Dist Tools Common	103,701.21	89,473.91	89,463.02
FLEET, TOOLS & COMM	A.0006059.004	SD-Dist Dist Tools and Equip	100,951.88	100,951.88	100,951.88
FLEET, TOOLS & COMM	A.0006059.003	ND-Dist Electric Tools and Equip	69,888.89	69,888.89	69,888.89
FLEET, TOOLS & COMM	A.0006059.474	Nspm Metering Sys-Tools & Equi	69,028.67	69,028.67	69,028.67
FLEET, TOOLS & COMM	A.0006059.478	Logistics - Security Equipment	36,118.83	34,852.09	35,876.39
FLEET, TOOLS & COMM	A.0006059.473	Logistics - NSPM - Tools - ND	16,967.40	14,678.79	14,677.03
FLEET, TOOLS & COMM	A.0006059.477	Logistics - Fencing - NSPM	10,939.26	8,970.80	8,969.30
FLEET, TOOLS & COMM	A.0006059.479	Logistics Security Eqiupment N	10,667.71	8,970.60	8,969.30
FLEET, TOOLS & COMM	A.0005549.006	NSPM-Dist Sub Communication Eq	6,183.51	4.95	-
FLEET, TOOLS & COMM	A.0006059.021	SD-Dist Logistics	4,353.36	4,353.36	4,353.36
FLEET, TOOLS & COMM	A.0005516.030	Scrap Sale Credits-MN	38.31	-	-
FLEET, TOOLS & COMM	A.0005549.043	ND Communications Equipment	(936.36)	(0.71)	-
MANDATES	A.0010167.001	LINE Relocation Hennepin Ave Road P	13,533,763.22	-	-
MANDATES	A.0010011.001	MN - OH Relocation Blanket	11,143,324.16	11,158,550.78	11,378,180.30
MANDATES	A.0010154.002	LINE Relocation 4th Street Road Pro	8,313,600.98	-	-
MANDATES	A.0010011.002	MN - UG Relocation Blanket	7,526,736.21	7,932,350.15	8,161,490.82
MANDATES	A.0010143.005	Relocation MPLS SWLRT Road Project	4,397,886.82	-	-
MANDATES	A.0010143.002	Relocation EDINA SWLRT Road Project	2,150,936.81	-	-
MANDATES	A.0010154.001	VAULT Relocation 4th Street Road Pr	1,941,661.87	-	-
MANDATES	A.0010011.004	MN - Mandate WCF Blanket	1,812,772.36	2,828,764.29	4,069,462.12
MANDATES	A.0010069.003	MPLS Mandates WCF	1,049,342.79	8,007,179.39	9,628,634.39
MANDATES	A.0010011.003	MN - UG Service Conversion Blanket	868,910.20	876,282.84	901,501.94
MANDATES	A.0010019.010	MN - Pole Transfer (3rd Party) Blan	439,914.58	439,999.98	440,000.00
NEW BUSINESS	D.0005014.004	MN Elec Distribution Transformers	22,816,000.00	22,816,000.00	24,800,000.00
NEW BUSINESS	A.0010003.002	MN - UG Extension Blanket	19,106,134.85	22,009,821.17	25,592,354.16
NEW BUSINESS	A.0010003.004	MN - UG New Services Blanket	8,739,492.93	8,832,160.28	9,165,158.73
NEW BUSINESS	D.0005014.021	MN-Electric Meter Blanket	5,616,000.00	5,616,000.00	5,616,000.00
NEW BUSINESS	A.0010003.001	MN - OH Extension Blanket	2,297,951.81	2,440,167.98	2,528,898.81

Capital Budget Groupings	WBS Level 2 #	Description	State of MN Electric Jurisdiction 2021	State of MN Electric Jurisdiction 2022	State of MN Electric Jurisdiction 2023
NEW BUSINESS	A.0010003.003	MN - OH New Services Blanket	761,260.39	808,535.72	838,573.33
NEW BUSINESS	A.0010003.005	MN - OH New Street Light Blanket	331,634.16	347,320.12	357,320.21
NEW BUSINESS	A.0010003.006	MN - UG New Street Light Blanket	54,397.24	22,946.27	23,946.15
NEW BUSINESS	A.0005506.001	MNOH Street Lights-MN	49.70	-	-
NEW BUSINESS	A.0006062.001	Distribution CIAC MN Elec	(3,702,000.00)	(3,813,000.00)	(3,813,000.00)
SOLAR	A.0005566.015	SE Solar Garden Extensions - E	5,247,083.69	1,566,134.32	467,474.41
SOLAR	A.0005566.017	Extend facilities to serve NW	354,774.02	25,681.30	1,858.92
SOLAR	A.0005566.023	Solar Garden Ext - WBL	217,954.21	65,054.31	19,418.01
SOLAR	A.0005566.021	MN-Solar Garden Sub Comm	37,646.42	11,234.71	3,352.89
SOLAR	A.0005566.022	MN-Solar Garden Sub Work	29,469.93	8,795.72	2,625.29

Distribution's O&M Costs by Category: 2017-2023
NSPM-Electric
(Dollars in Millions)

NSPM Electric	2017 Actual	2018 Actual	2019 Actual	2020 Forecast	2021 Budget	2022 Budget	2023 Budget
Internal Labor	47.5	50.9	48.3	47.2	55.1	55.5	56.7
Contract Labor	8.7	10.3	14.1	8.9	6.8	7.5	9.5
Vegetation Management	31.1	32.4	35.3	22.9	43.0	46.8	40.9
Damage Prevention Locates	7.3	6.9	7.0	11.2	12.5	12.9	13.3
AGIS	-	0.9	1.1	2.2	7.4	8.9	5.9
Other (Fleet, Materials, Employee Expenses, Etc.	13.7	15.3	10.0	7.4	8.4	8.0	7.9
Total*	**108.3**	**116.8**	**115.9**	**99.7**	**133.1**	**139.7**	**134.3**

**Includes O&M associated with the Company's AGIS deployment. These O&M costs (with the exception of internal labor) will be recovered through the TCR Rider.*