Direct Testimony and Schedule
Marty D. Mensen

Before the South Dakota Public Utilities Commission
State of South Dakota

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

Docket No. EL22-____
Exhibit___(MDM-1)

Distribution

June 30, 2022

TABLE OF CONTENTS

SCHEDULES

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Marty D. Mensen. 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 (the Company or NSPM) and an operating company of Xcel Energy Inc. (Xcel Energy).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over 11 years of experience in the utility industry. I joined Interstate Power and Light, an operating company of Alliant Energy in 2011 and served in various leadership roles. I started with Xcel Energy Services Inc. in early 2022. In my current role, I am responsible for the electric distribution design and construction activities for the Company's service areas in the states of North Dakota, Minnesota, South Dakota, Michigan, and Wisconsin. My Statement of Qualification is attached as Exhibit___(MDM-1), Schedule 1.

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

A. My testimony supports the prudence of the revenue requirement increases attributable to the Distribution function driving the need for this rate case as described by Company witness Mr. Allen D. Krug. The Company has made significant capital additions that have been placed in service since 2013.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. I begin my testimony by discussing the Distribution function's capital expenditures, including key programs and projects, and how those support Xcel Energy's provision of safe and reliable service at reasonable costs. 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. Much of Distribution's investments and efforts are focused on maintaining the reliability, resiliency, and health of our existing distribution facilities. In order to maintain these facilities, we regularly evaluate the health of the key components of our distribution system and make the necessary investments to ensure these facilities are safe and reliable. This includes an evaluation of the condition, age, and performance of the key components of our system such as poles, underground cables, and substation transformers. We also must make significant investments to support system capacity needs due to increased loads, update existing infrastructure, respond to severe weather events, and carry out projects in response to public works projects.

From 2014 to 2015, the Company's distribution capital investments increased significantly, which was in large part a result of the Falls Substation project along with a number of other capacity projects. Capital investments then declined in 2016, 2017, and 2018 before increasing again in 2019 as a result of storm restoration work resulting from multiple severe weather events. There was then a notable decrease in 2020 attributable to the initial year of the pandemic before an increase in 2021 resulting from increased pole replacement investments, an increase in new business, and storm restoration. The Company's investments have resulted in significantly improved reliability from 2014 to 2020, and I conclude the capital portion of my Direct Testimony by presenting the data showing those improvements.

I then present Distribution's historical and forecasted operations and maintenance (O&M) expenditures and how they support Distribution's key mission of supporting system reliability. The Company's distribution's O&M expenditures include the maintenance of existing assets, the programmatic annual inspections of poles and replacement of poles as necessary, vegetation management, and damage prevention through locating underground electrical facilities. As a result of strong management practices, we have been able to keep our O&M costs relatively flat since 2016. There was an increase between 2020 and 2021; however, that is partly attributable to 2020 being the initial year of the pandemic. The 2021 O&M spending was still lower than either 2018 or 2019.

Finally, I discuss the Company's Meter Replacement project. We have used our existing meters for more than 20 years, and the time has now come to replace them with more up-to-date technology. The Company has chosen modern, Advance Metering Infrastructure (AMI) meters with Distributed Intelligence (DI) functionality, and we are making related improvements to our distribution communications and control systems. These investments will provide the Company with more granular information and control over the distribution system while also allowing us to provide customers with more information about their energy usage along with tools they can use to lower their monthly bills. It was the right time to replace the current meters and it made sense to pair that investment with related projects. Implementation of the Meter Replacement project requires capital investments, and I present specific figures, including forecasted spending beyond the 2021 test year.

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. My testimony is organized into the following sections:

- *Section I* – Introduction
- *Section II* – Distribution Functions
- *Section III* – Distribution Capital Investments
- *Section IV* – Distribution Operations and Maintenance Expenditures
- *Section V* – Meter Replacement Project
- *Section VI* – Conclusion

II. DISTRIBUTION FUNCTIONS

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S DISTRIBUTION SYSTEM IN SOUTH DAKOTA.

A. The Company's distribution system serves approximately 97,500 electric customers across South Dakota. The distribution system is the final link that provides electricity to our customers' homes and businesses, safely and reliably. The Company's distribution system in South Dakota includes 18 distribution substations, 5 step-down substations served from distribution feeders, and 2,098 line miles of distribution lines.

Q. WHERE ARE THOSE DISTRIBUTION SUBSTATIONS LOCATED?

A. Our distribution substations and step-down distribution substations served from distribution are located in the cities of Alexandria, Bridgewater, Canistota, Canton, Centerville, Dell Rapids, Emery, Lennox, Marion, Salem, and Sioux Falls.

Q. WHAT ARE THE RESPONSIBILITIES OF THE DISTRIBUTION BUSINESS UNIT?

A. The Distribution organization's investments and work directly impact the daily lives of our customers. 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 enhance the performance and reliability of the distribution system.

The work performed by Distribution is essential to ensuring that the electric service our customers receive is safe, reliable, and affordable. Our work includes new construction to extend service to new customers or increasing the capacity of the system to accommodate new or increased load, repairing facilities damaged during severe weather to restore service to customers quickly, and performing regular maintenance and repairs on poles, wires, underground cables, metering, and transformers.

Our organization is also responsible for the primary implementation and support for the Company's Meter Replacement project. I discuss the Meter Replacement project further in Section V of my Direct Testimony.

Q. PLEASE DESCRIBE THE STRUCTURE OF THE DISTRIBUTION BUSINESS UNIT.

A. To serve South Dakota customers, Distribution divides its work into five functional areas:

- *Distribution 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*. Responsible for 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;
- *Planning and Performance*. Responsible for business planning, consulting, analytical services and performance governance and management; and
- *Meter Replacement Project and Metering*. Responsible for implementing the Meter Replacement project and metering.

Q. HOW MANY EMPLOYEES WORK IN THE DISTRIBUTION BUSINESS UNIT?

A. Across the Northern States Power Minnesota operating company (which encompasses our South Dakota operations), there are 510 full-time employees performing the functions of the Distribution business unit. Of those 510, 52 are based in the Sioux Falls Service Center and/or directly support operations in the region covered by the Sioux Falls Service Center, which includes adjacent portions of Minnesota. Approximately 70% of those 52 employees (36 full-time employees) are in bargaining units. Additionally, employees of XES provide support to all Xcel Energy operating companies. The budget of each operating company—including that of NSPM—assumes support by a certain number of employees of the Service Company based on the number of line miles in the service territory. There are currently 244 full-time employees in the Xcel Service Company. NSPM assumes support of 85 full-time Service Company employees (based on NSPM containing 35% of total Xcel Energy Distribution line miles). Finally, certain employees of the Gas Engineering and Operations business area support the electric utility's work.

III. DISTRIBUTION CAPITAL INVESTMENTS

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

A. In this section of my Direct Testimony, I describe the capital investments the Distribution business unit makes to deliver safe, reliable electric service to our South Dakota customers.

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. First, I provide a broad overview of the types of capital investments the Distribution business unit makes and the process for planning and implementing those investments. Next, I discuss Distribution business unit capital investments made since 2014, which the Company is proposing to add to the rate base, and which are a driver for the broader rate case. (I present the capital additions related to the Meter Replacement initiative in Section V).

A. Types of Distribution Capital Investments

Q. WHAT TYPES OF CAPITAL INVESTMENTS DOES THE DISTRIBUTION BUSINESS MAKE TO PROVIDE SAFE AND RELIABLE SERVICE FOR SOUTH DAKOTA CUSTOMERS?

A. The Distribution business unit makes capital investments to maintain, and where possible enhance, the reliability and functionality of the distribution system, extend service to new customers, and relocate facilities in response to road construction or other governmental projects. Also, in partnership with other areas of the Company, Distribution makes capital investments in support of the Meter Replacement project.

Q. CAN YOU EXPAND ON EACH OF THESE CATEGORIES OF INVESTMENT?

A. Yes. The majority of our investments are made to maintain the health and reliability of our facilities through replacement of aging or damaged equipment. By making these investments, we maintain and enhance reliability of service for customers. As I discuss further below, since our last South Dakota rate case, we made investments in poles, feeder lines, substation transformers, and replacement of underground cables—all to maintain the health of these key components of our system and thereby provide reliable service for our South Dakota customers. Where necessary, we also make necessary improvements to provide increased capacity. These capacity investments increase the ability of the distribution system to handle system load growth and to serve load when other elements of the distribution system are out of service. Projects in this category include installing new or upgraded substation transformers and distribution feeders.

The Company also makes capital additions 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. Such mandate projects typically result in updated distribution infrastructure that benefits the system and customers. The Company also invests in the tools, equipment, and fleet that its personnel need to perform their jobs.

Additionally, since 2019, Xcel Energy has made strategic investments in the Company's Meter Replacement project, which is discussed in Section V below.

Q. PLEASE SUMMARIZE THE PROCESS THE COMPANY USES TO DETERMINE WHAT INVESTMENTS TO MAKE.

A. On an ongoing basis, the Company identifies necessary routine and non-routine investments into the distribution system. The Company divides expenditures into routine and non-routine categories depending upon whether we expect the expenditure to re-occur. Regarding routine projects, Distribution makes those capital additions necessary as a regular, common part of maintaining a properly functioning distribution system. For non-routine projects, Distribution identifies risks to the distribution system and possible capital additions to mitigate those risks, and scores the possible projects to determine a priority order. The Company uses that priority order to guide its investments as the amount of capital varies from year to year. At the same time, the Company remains flexible so that if an emergency occurs during a given year, such as the storms and flooding in 2019, the Company can adjust the priority of projects on the approved list. In summary, we meet identified needs and requirements, adjust to changing circumstances, and prudently promote the long-term health of the distribution system.

Q. HOW ARE DISTRIBUTION'S CAPITAL ADDITIONS ALLOCATED TO THE SOUTH DAKOTA JURISDICTION?

A. As the last mile of service, Distribution's activities accrue benefits that are more localized in nature than other Company functions such as Energy Supply, Transmission, and Business Systems (Information Technology) which support the entire NSP System. Consequently, Distribution's capital and O&M costs tend to be differently allocated than system-wide resources.

Distribution's capital additions are, in general, directly assigned to the South Dakota jurisdiction—just as Distribution's capital additions in North Dakota and Minnesota are directly assigned to those jurisdictions. For example, all of the costs of a Distribution capital addition at a substation in the Sioux Falls area would be direct assigned to the South Dakota jurisdiction. This is because the distribution capital additions support local electric service in the particular jurisdiction.

With the Company's Meter Replacement project, we also utilize allocators for certain initiative costs rather than merely directly assigning them. We take this approach because some elements of the project are more akin to networks that provide broad-based support for the distribution system, rather than being local in nature. Company-wide deployment of these technologies and software to support them are, therefore, treated more like information technology investments rather than local investments in distribution.

Q. PLEASE DESCRIBE HOW DISTRIBUTION'S CAPITAL INVESTMENTS BENEFIT SOUTH DAKOTA CUSTOMERS.

A. Distribution's capital investments support various initiatives, activities, and responsibilities. For example, these investments keep assets working properly, provide customers with reliable service, serve new load, support new capacity, accommodate public works projects, and provide employees with the tools and equipment they need to perform their job responsibilities.

Q. HOW DO CAPITAL INVESTMENTS KEEP ASSETS WORKING PROPERLY AND PROVIDE CUSTOMERS WITH RELIABLE SERVICE?

A. Distribution invests capital to replace infrastructure that may experience or be particularly susceptible to failure and, as a result, negatively impact service reliability and increase O&M expenditures needed to repair the equipment. 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 life. This category also captures replacements due to storms and public damage. Distribution designates capital additions in this category as Asset Health and Reliability projects.

Q. HOW DO CAPITAL INVESTMENTS SERVE NEW LOAD?

A. Distribution invests capital to build 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.

Q. HOW DO CAPITAL INVESTMENTS SUPPORT NEW CAPACITY?

A. Distribution's investments in support of capacity increase the ability of the distribution system to handle system load growth and to serve load when other elements of the distribution system are out of service. Projects in this category include installing new or upgraded substation transformers and distribution feeders.

Q. HOW DO CAPITAL ADDITIONS ACCOMMODATE PUBLIC WORKS PROJECTS?

A. When a unit of government widens a road, for example, the Company makes a capital investment to relocate utility infrastructure in public rights-of-way. These mandate projects typically result in updated distribution infrastructure.

Q. HOW DO CAPITAL ADDITIONS PROVIDE EMPLOYEES WITH THE TOOLS AND EQUIPMENT THEY NEED TO PERFORM THEIR JOB RESPONSIBILITIES?

A. Distribution makes capital investments in tools, equipment, communication equipment, and costs to locate existing utility lines. Distribution also invests in replacing fleet vehicles that have reached the end of their useful lives.

B. Overview of Capital Additions Through 2021

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S NON-METER REPLACEMENT DISTRIBUTION PLANT ADDITIONS FROM 2013 TO 2021.

A. Table 1 below reflects Distribution capital additions placed in service from 2014 through 2021, broken down by category.

Table 1

Distribution Non-Meter Replacement Project Capital Additions 2013-2021

State of SD Electric Jurisdiction Plant Additions (includes AFUDC)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Asset Health & Reliability	$8.9	$3.6	$4.8	$1.8	$6.0	$4.1	$8.3	$7.9	$9.4
New Business	$4.2	$6.5	$6.5	$7.3	$5.2	$9.4	$5.8	$4.0	$9.1
Capacity	$5.4	$4.0	$15.8	$11.3	$5.3	$0.5	$4.0	$0.7	$0.7
Mandates	$0.8	$1.1	$1.0	$0.4	$0.6	$1.5	$0.8	$0.8	$2.4
Tools and Equipment	$0.3	$0.2	$0.3	$0.3	$0.6	$0.4	$0.2	$0.4	$0.3
Total	**$19.5**	**$15.5**	**$28.4**	**$21.0**	**$17.8**	**$15.9**	**$19.1**	**$13.7**	**$21.9**

Q. WHAT TRENDS DOES THIS TABLE ILLUSTRATE IN THE COMPANY'S NON-METER REPLACEMENT PROJECT DISTRIBUTION CAPITAL ADDITIONS FROM 2014-2021?

A. The table illustrates we made investments in refreshing the system since the 2013 test year used in our last rate case. One notable trend is that capital additions peaked in 2015 before declining for three years, and then have increased again somewhat. The 2015 peak is the result of significant capacity additions, which are discussed below.

Q. WHAT DROVE THAT INCREASE IN CAPITAL ADDITIONS IN 2015, 2019, AND 2021?

A. As I noted above, the 2015 increase is attributable to a number of capacity projects, including the Falls Substation project. Capital additions then decreased for three years before increasing again in 2019. That 2019 increase largely results from additional Asset Health & Reliability spending in the form of storm restoration work carried out that year in response to multiple severe weather events, including the severe thunderstorms and tornadoes in the Sioux Falls area on September 10-11 of that year. After a decrease in 2020, there was then another increase in 2021, which resulted from increased pole replacement costs, an increase in New Business resulting from local economic growth, increased mandates work, and storm restoration work.

1. Investments Across the Distribution System in South Dakota

Q. SINCE THE LAST RATE CASE, DID THE COMPANY MAKE ANY CAPITAL INVESTMENTS BROADLY ACROSS THE DISTRIBUTION SYSTEM IN SOUTH DAKOTA?

A. Yes. The Company made a variety of investments to enhance the reliability and performance of the distribution grid throughout our South Dakota service territory.

Q. PLEASE SUMMARIZE THOSE INVESTMENTS.

A. The Company invested in pole replacements and new cable. I describe each of these key investments in more detail below.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS IN POLE REPLACEMENT.

A. The Company invests in rebuilding, replacement, and renewal of poles to enable them to withstand weather events, continue to provide a sturdy underpinning for the distribution grid, and prevent safety hazards for customers or Company employees. The NSPM distribution system has approximately 500,000 wooden poles in service of which 33,402 are in South Dakota.[1] These poles have a service life, on average, of 40 to 50 years; those poles at the end of their service life have the highest rate of failure. Pole rot at the base of the pole can be a cause of pole failure, especially during storms. Pole failures create outages and so maintaining the integrity of the Company's poles is important for the maintaining the reliability of the distribution system.

To identify poles in need of replacement, the Company employs a 12-year inspection cycle. The Company seeks to replace poles identified for

[1] There are also 5,629 wood poles in South Dakota not owned by the Company to which Company lines are attached.

replacement within one year of the inspection. The number of poles inspected each year can vary depending on overall budget management efforts, and the number of poles replaced each year depends on various factors including the rejection rate of the inspected poles in prior years, resource limitations, and emergent work. 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 are identified for replacement has increased since 2012. For instance, in 2018, the rejection rate (the proportion of poles that fail testing and need to be replaced or reinforced to ensure the physical integrity of the pole) was 19.6 percent, and for 2020 it was 18.8 percent. In comparison, the NSPM company-wide rejection rates for 2014 to 2017 were between 9.5 percent and 11 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 step change in the rejection rate underscores the need to place greater focus on these key assets.

In any given year, the Company inspects approximately 1/12 of its overall inventory of poles across South Dakota, North Dakota, and Minnesota. However, the number of poles inspected in South Dakota can vary significantly from year to year, and so, consequently, can the number of pole replacements that are necessary. In 2021, the Company replaced 999 poles in South Dakota, which is a relatively high number historically. Currently, the Company is working through a backlog of poles identified for replacement, which results from a higher volume of testing within South Dakota in recent years and increased failure rates.

Capital additions for pole replacement totaled $10,448,558 from 2014 to 2021.

Q. PLEASE DESCRIBE THE COMPANY'S INVESTMENTS TO ENHANCE RELIABILITY OF CABLE THROUGHOUT THE DISTRIBUTION SYSTEM.

A. Historically, South Dakota customers have experienced reliability issues due in part to failing 500 MCM[2] unjacketed cable. This is an issue experienced throughout the electric utility industry. The technology and manufacturing of cable has improved over the years and a jacket around the concentric neutrals provides much better protection from soil and environmental corrosion extending the useful life of the cable. In response to that advancement, the Company has taken a proactive approach to improving reliability by replacing unjacketed cable with jacketed cable. Over the last five to seven years, the Company has proactively replaced old unjacketed cable. Similarly, the Company has prioritized the replacement of underground residential distribution cable that was originally installed in the 1970s and has been failing in recent years. Additionally, the Company has invested in underground extensions, conversions, reinforcements, and rebuilds. These investments in undergrounding created benefits for our customers of increased reliability—since wires underground are less impacted by storms and animals than overhead wires—and improved aesthetics. The Company has invested in this initiative consistently, making capital additions totaling $7,147,506 from 2014 to 2021.

Q. PLEASE DESCRIBE THE COMPANY'S DEPLOYMENT OF LED STREETLIGHTS ACROSS ITS SOUTH DAKOTA SERVICE TERRITORY.

A. In 2017, we deployed LED streetlights. These LED streetlights create a variety of benefits for customers: compared to incandescent streetlights, LED streetlights are more energy-efficient, last longer, and put less strain on the

[2] MCM stands for circular mill. It is a unit of measurement used to describe the size of electrical wires.

grid. In addition, the switch to LED lighting promotes safety by improving nighttime visibility for both drivers and pedestrians. The Company made a total of $915,269 in capital additions on LED streetlights in 2017.

2. *Distribution Investments in Specific Portions of the Company's South Dakota Service Territory*

Q. HAS THE COMPANY MADE KEY CAPITAL INVESTMENTS IN PARTICULAR PORTIONS OF ITS SOUTH DAKOTA SERVICE TERRITORY SINCE 2013?

A. Yes, since our last rate case, we implemented action plans to enhance reliability of service in and around specific areas by constructing a new substation, installing new transformers at existing substations, and installing new feeders. These investments also increased the distribution system's capacity to handle local load growth on the system and to serve load when other elements of the distribution system are out of service.

Q. PLEASE BRIEFLY LIST THE KEY INVESTMENTS MADE IN SPECIFIC PORTIONS OF THE COMPANY'S SOUTH DAKOTA SERVICE TERRITORY IN 2013.

A. The Company completed seven key investments in its South Dakota service territory in 2013. First, it upgraded the transformer capacity at the Canistota Junction substation. Second, the Company reinforced a reactor at the West Sioux Falls substation to increase capacity. Third, the Company reinforced the capacity of the West Sioux Falls transformers by reinforcing the low voltage bushings on each of the transformers. Fourth, a feeder was extended to provide additional ties to the stepdown substation serving the town of Dell Rapids. Fifth, the Company reinforced a single-phase section of feeder to three-phase and installed a feeder tie in the Split Rock Heights and Anderson area. Sixth, an additional feeder tie was installed between feeders to mitigate risk for Dell Rapids. Finally, the Company installed a new substation on Louise Avenue in Sioux Falls and reinforced a feeder.

Q. PLEASE BRIEFLY LIST THE KEY INVESTMENTS MADE IN SPECIFIC PORTIONS OF THE COMPANY'S SOUTH DAKOTA SERVICE TERRITORY IN 2014.

A. The Company completed three key investments in its South Dakota service territory in 2014. First, the Company completed the 4 kV conversion on the feeders and the retirement of the 4 kV transformers at the South Sioux Falls substation. This resulted in the mitigation of risk as well as compliance with environmental standards regarding oil containment. Second, a feeder tie was installed between two feeders in the vicinity of Augustana University. Finally, a new feeder was installed to provide additional capacity in the Harrisburg and Worthing areas.

Q. PLEASE BRIEFLY LIST THE KEY INVESTMENTS MADE IN SPECIFIC PORTIONS OF THE COMPANY'S SOUTH DAKOTA SERVICE TERRITORY IN 2015.

A. The Company completed one key investment in its South Dakota service territory in 2015. The Company reinforced the Centerville TR1 transformer and converted the system from 4 kV to 13.8 kV.

Q. PLEASE BRIEFLY LIST THE KEY INVESTMENTS MADE IN SPECIFIC PORTIONS OF THE COMPANY'S SOUTH DAKOTA SERVICE TERRITORY IN 2016.

A. The Company completed eight key investments in its South Dakota service territory in 2016. First, the Company installed a transformer and carried out a feeder conversion to increase the capacity at the Salem substation. Second, 4 kV equipment at the Cliff Avenue substation was retired and the feeder loads were converted to 13.8 kV and transferred to the Falls substation in late 2016, early 2017.[3] Third, the Company installed a new feeder at the Cherry Creek substation. Fourth, the Company installed a new Falls substation as part of the Northern Sioux Falls Transmission Plan which converted much of the 69 kV infrastructure in the area to 115 kV. This new substation was built at 115-13.8 kV to allow the retirement of the Sioux Falls 69-4 kV substation. Fifth, the Company installed the new South Renner substation. This new substation provided an additional 34.5 kV source for the area, improving the operability between Cherry Creek and Lawrence 34.5 kV systems. Sixth, the Company installed switches for Cliff Avenue substation and extended the feeder. Seventh, the Company installed a tie for a feeder in the South Sioux Falls substation in order to reconfigure it to perform load transfers. Finally, the Company reconfigured a feeder at the Minnehaha substation, which mitigated risk and allowed for additional 13.8 kV ties to the area.

Q. PLEASE BRIEFLY LIST THE KEY INVESTMENTS MADE IN SPECIFIC PORTIONS OF THE COMPANY'S SOUTH DAKOTA SERVICE TERRITORY IN 2017.

A. The Company completed three key investments in its South Dakota service territory in 2017. First, the Company reinforced a feeder tap, located from Lawrence substation to the town of Brandon, from single-phase to three-phase. This resulted in additional capacity and provided opportunities for customers to adopt three-phase delivery choices. Second, the Company removed the legacy feeder network located in downtown Sioux Falls. Removing the network allowed for new feeders from the Falls substation to provide service in the downtown area as well as provided increased capacity. Finally, the Company retired the Howard Junction substation and replaced

[3] This project was completed in late-2016 to early-2017.

service to the town of Howard with a step down served from the Salem substation.

Q. PLEASE BRIEFLY LIST THE KEY INVESTMENTS MADE IN SPECIFIC PORTIONS OF THE COMPANY'S SOUTH DAKOTA SERVICE TERRITORY IN 2018.

A. The Company completed one key investment in its South Dakota service territory in 2018. The Company extended a feeder to serve new customer load in the Lake Lorraine development.

Q. PLEASE BRIEFLY LIST THE KEY INVESTMENTS MADE IN SPECIFIC PORTIONS OF THE COMPANY'S SOUTH DAKOTA SERVICE TERRITORY IN 2019.

A. The Company completed one key investment in its South Dakota service territory in 2019. The Company extended a feeder from the Louise substation to provide load relief to an existing feeder and provide additional ties for the Cherry Creek substation.

Q. PLEASE BRIEFLY LIST THE KEY INVESTMENTS MADE IN SPECIFIC PORTIONS OF THE COMPANY'S SOUTH DAKOTA SERVICE TERRITORY IN 2020.

A. The Company completed one key investment in its South Dakota service territory in 2020. The Company provide additional capacity to Dell Rapids by installing a new stepdown and tie with the 34.5 kV feeders serving the town.

C. Overview of Known and Measurable Capital Additions Through 2021

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S DISTRIBUTION PLANT ADDITIONS DURING THE 24-MONTH KNOWN AND MEASURABLE PERIOD.

A. Table 2 below reflects known and measurable Distribution capital additions that will be placed in service in 2022 and 2023, broken down by category. This does not include the capital additions discussed in Section V below.

Table 2
Known and Measurable Capital Additions
(in millions)

Category	2022	2023
Asset Health & Reliability	$2.73	$2.39
New Business	$5.00	$5.30
Capacity	$0.003	$20.16
Mandates	$2.58	-
Total	$10.32	$27.86

Q. WHAT DOES TABLE 2 SHOW?

A. Table 2 shows that the Company is continuing to make significant investments to maintain the reliability of the distribution system. The known and measurable investments for 2022 are relatively low when compared to recent years, but that is offset by significant additions planned for 2023.

Q. WHAT ARE THE 2022 ADDITIONS?

A. The new business additions consist of extensions of underground distribution lines and purchases of transformers made in response to customer growth. The other significant areas are asset health and reliability investments in the replacement of wooden poles and a mandate project that the Company must carry out in response to the widening of a portion of State Highway 34.

Q. PLEASE EXPLAIN THE 2023 ADDITIONS.

A. Two large capacity projects, the construction of a new Great Plains substation in Sioux Falls and the addition of a second transformer at the Louise substation in Sioux Falls (and related feeder installation), constitute the 2023 known and measurable additions in this area. The remainder consists of new business additions similar to those in 2022 and continued pole replacement.

Q. WHY ARE THE 2022 AND 2023 ASSET HEALTH AND RELIABILITY ADDITIONS KNOWN AND MEASURABLE?

A. The asset health and reliability capital additions consist of pole replacements. As I noted above, the Company is working through a backlog of poles that have already been identified as needing to be replaced. As a result, the need for the work is already certain.

Q. WHY ARE THE 2022 AND 2023 NEW BUSINESS ADDITIONS KNOWN AND MEASURABLE?

A. These amounts consist of electric distribution transformers and customer-driven underground cable extensions. These budgets are based on historic trends and anticipated growth rates. Capital additions of this type have historically been quite predictable, and the transformers have already been purchased.

Q. WHY ARE THE CAPACITY ADDITIONS KNOWN AND MEASURABLE?

A. As I noted above, the capacity additions consist of two, specific budgeted projects. The majority of the work is planned for 2023.

Q. WHY IS THE 2022 MANDATE PROJECT KNOWN AND MEASURABLE?

A. As I noted above, the 2022 mandate amount is a response to a specific road widening project. It is summer construction season in South Dakota and so the Company is now quite certain that the utility relocation work in question will take place and be complete this year. The Company did not, however, include any mandate work for 2023 as we do not have as much certainty with regard to what projects may or may not take be carried out next year.

D. Reliability Results

Q. YOU HAVE DESCRIBED PARTICULAR INVESTMENTS IN THE DISTRIBUTION SYSTEMS AND GENERALIZED INVESTMENTS THROUGHOUT THE DISTRIBUTION SYSTEM. HAVE THE COMPANY'S DISTRIBUTION INVESTMENTS PROVIDED RELIABILITY BENEFITS FOR CUSTOMERS?

A. Yes. As detailed below, the Company's investments in the distribution system have increased the reliability of service to customers.

Q. HOW DOES THE COMPANY TRACK DISTRIBUTION SYSTEM RELIABILITY?

A. The most common industry metrics for tracking reliability performance are the System Average Interruption Duration Index (SAIDI) and the System

Average Interruption Frequency Index (SAIFI), which are tracked both on all days and on a normalized basis to exclude major storm events.

Q. WHAT IS THE TREND OF THE COMPANY'S SAIDI AND SAIFI METRICS?

A. The Company's SAIDI and SAIFI performance has varied over time. However, the performance over the last five years has been favorable against the eight-year average since the last rate case. The Company continues to be a leader in terms of reliability performance. The following table provides details:

Table 3

State of South Dakota System Level Indices – IEEE State Normalized

	2014	2015	2016	2017	2018	2019	2020	2021	8-Year Average
SAIDI	75.29	89.62	83.76	55.74	58.57	62.57	56.22	57.62	67.42
SAIFI	0.92	0.90	0.79	0.52	0.48	0.58	0.62	0.62	0.68

Q. WHAT ELSE DOES TABLE 3 TELL YOU ABOUT THE COMPANY'S RELIABILITY PERFORMANCE??

A. Table 3 demonstrates that, from 2014 to 2021, the Company has materially enhanced the reliability of the distribution system. While there can be reliability challenges in individual years (such as more or less extreme weather), the long-term trend indicates that the Company's continued investment in the distribution system and our dedication to the customer experience is yielding reliability benefits. Comparing 2014 to 2021 identifies over 20% and 30% improvements to SAIDI and SAIFI metrics respectively which demonstrates that, over time, the Company's investments are improving service for customers.

IV. DISTRIBUTION OPERATIONS AND MAINTENANCE EXPENDITURES

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

A. First, I provide a broad overview of the types of Distribution operations and maintenance (O&M) expenses and the process for planning and implementing that work. Next, I present Distribution's 2014-2021 O&M expenditures, including key drivers and trends.

A. Nature of and Process for Distribution O&M Expenses

Q. FOR WHAT TYPES OF ACTIVITIES DOES DISTRIBUTION INCUR O&M EXPENSES?

A. Distribution's O&M expenditures fall into four categories. First, Distribution makes O&M expenditures on existing pole and wire assets, including equipment maintenance, underground cable fault repair, storm repair, and inspections. Second, Distribution makes programmatic annual inspections of poles and replacement of poles as necessary. Third, the Company manages vegetation to maintain proper line clearances and distribution pole right-of-way and address vegetation-caused outages. Fourth, the Company prevents damage by locating underground electric facilities.

Q. PLEASE DESCRIBE THE COMPANY'S WORK TO MANAGE VEGETATION.

A. The Company and its contractors prune, remove, mow, and apply herbicide to trees and tall-growing brush on and adjacent to the Company's rights-of-way to limit preventable vegetation-related interruptions.

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

A. An effective Vegetation Management program is essential for providing reliable service to our customers. Tree-related incidents are among the top causes for electrical outages on our NSPM distribution system as well as the South Dakota jurisdiction. Meeting our vegetation management goals will minimize tree-related interruptions and promote public and employee safety.

Q. PLEASE DESCRIBE THE COMPANY'S DAMAGE PREVENTION PROGRAM.

A. The Company makes expenditures to locate underground electric facilities and mark those locations. These efforts help excavators and customers locate underground electric infrastructure to avoid accidental damage and safety incidents. 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.

Q. DOES THE COMPANY USE CONTRACTORS FOR ITS VEGETATION MANAGEMENT AND DAMAGE PREVENTION PROGRAMS?

A. Yes, the Company utilizes contractors extensively to implement our Vegetation Management and Damage Prevention programs. These programs require performance of specialized tasks (e.g., tree trimming, pole inspections, underground facility locating) by a seasonal workforce. Accordingly, the Company has determined that the use of contract labor is more cost effective and efficient than utilizing employees. With contractor labor, the Company can competitively bid out 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. This flexibility is important given the seasonal nature of this work. If the Company were to hire employees for these positions, we would have to find a way to deploy this workforce to other areas during the winter months when these tasks are not performed at the same volume as in the summer and/or as overall annual work volumes change due to the economy or other factors.

Q. HOW ARE DISTRIBUTION O&M EXPENDITURES ALLOCATED?

A. Similar to our capital additions, Distribution's O&M expenses are generally direct assigned to the South Dakota jurisdiction to the extent they are solely serving that jurisdiction. For example, vegetation management costs are direct assigned to the area where the work is completed. For example costs of vegetation management in the Sioux Falls area are assigned fully to the South Dakota jurisdiction. That said, certain Distribution O&M expenses are incurred on a Company-wide basis—for example, management costs, environmental services, planning, and certain engineering functions. These O&M expenses are allocated to the South Dakota jurisdiction using an allocation methodology.

B. O&M Expenses from 2014 to 2021

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

A. I present Distribution's expenditures on O&M, including key drivers and trends.

Q. PLEASE DESCRIBE DISTRIBUTION'S HISTORIC PATTERNS OF O&M SPENDING SINCE THE COMPANY'S LAST SOUTH DAKOTA RATE CASE.

A. Table 4 below shows the Company's South Dakota O&M distribution expenses for 2014 through 2021.

Table 4

South Dakota – Electric Distribution O&M Expenses 2014 – 2021 - $M

2014	2015	2016	2017	2018	2019	2020	2021
$8.1	$7.5	$7.2	$6.8	$7.2	$7.3	$6.1	$7.0

Q. WHAT DOES THIS TABLE SHOW?

A. Except for 2020, the initial year of the COVID-19 pandemic, since 2015 Distribution has historically spent between $6.8 and $7.5 million on O&M annually in support of maintaining and enhancing the reliability of the South Dakota distribution system. Our $7.0 million in O&M expenses for distribution for the 2021 test year fall within this range but notably were lower than they were in 2014 despite inflation and significant additions to our distribution system.

Q. WHAT WERE THE COMPANY'S DISTRIBUTION O&M EXPENSES FOR 2019 AND 2020?

A. As shown above in Table 4, the Company's South Dakota O&M expenditures were $7.3 million for 2019 and $6.1 million for 2020.

Q. WHAT WERE THE COMPANY'S DISTRIBUTION O&M EXPENSE IN THE TEST YEAR OF 2021?

A. As shown above in Table 4, the Company's O&M costs for South Dakota were $7.0 million for the 2021 test year. This was higher than 2020, but below the amount of the 2018 and 2019 expenditures.

Q. WHAT ACCOUNTS FOR THE INCREASE IN O&M EXPENDITURES FOR 2021 FROM THE LEVEL SEEN IN 2020?

A. The Company limited certain work during the initial year of the COVID-19 pandemic both to cut expenses and in response to public health concerns. However, in 2021 we returned to a level of O&M spending more typical of recent years.

V. METER REPLACEMENT PROGRAM

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

A. I describe the Company's Meter Replacement program, its purpose, the principal components, how they will interact and how they will enable and provide benefits to our customers. I also present the Company's capital costs for the initiative.

A. Overview

Q. WHAT IS THE METER REPLACEMENT PROGRAM?

A. The program is the Company's multi-year project to replace the meters located at our customers' premises and make supporting and related investments in the systems we use to manage and communicate with the equipment on our distribution grid.

Q. What is driving the need for the program?

A. The Company's current meters need to be replaced. Our present automated meter reading (AMR) technology is nearing end of life and our meter reading services vendor, Landis+Gyr (Cellnet) has informed the Company that it will no longer manufacture replacement parts for this system after 2022. Further, our current contract with Cellnet for meter reading services expires at the end of 2025. We have obtained good value from the AMR technology. It has worked efficiently for more than 20 years, but it is now time to move toward a new solution. Notably, our peers are also either in the process of transitioning to smart meters or have already done so.

In light of that need to transition away from our AMR meters, we surveyed the available options and determined that more advanced grid technology has reached a point where it is sufficiently mature that it is in our customers' best interests to purchase meters with advanced capabilities and deploy them along with related communication and control technologies. The Company previously implemented some of these technologies in pilot areas and based on the results of those pilots, we determined that it makes sense to pair replacement of existing AMR meters with some additional long-term investments. While the timing of the project is driven by the replacement of the AMR meters, the package of investments within the Meter Replacement program will also support our broader infrastructure needs.

Q. What individual technologies are involved?

A. Listed in the order in they are being deployed, the components of the Meter Replacement program are: (1) our Field Area Network (FAN) and (2) our

Advanced Metering Infrastructure (AMI). These elements will extend our visibility and control of the distribution system all the way to our customers' premises. The Company's new AMI meters also contain Distributed Intelligence (DI) capabilities which the Company plans to utilize.

Q. CAN YOU DESCRIBE EACH OF THESE COMPONENTS?

A. Yes. Here is an explanation of each of these technologies:

- **<u>Field Area Network</u>**: The FAN is the communications network that will link our AMI supporting systems to the new AMI meters, other new intelligent field devices, and the software used to monitor and operate the distribution grid.
- **<u>Advanced Metering Infrastructure</u>**: AMI is an integrated system of advanced meters, communications networks, and data management systems that enables secure two-way communication between customer meters and utilities' business and operation systems.
- **<u>Distributed Intelligence</u>**: DI refers to the distribution of computing power to the meters themselves. Each meter will contain the equivalent of a small computer and a Wi-Fi radio. This computing power at the edge of the distribution grid and the ability to communicate with customer-owned devices via Wi-Fi will allow customers to obtain greater insight into their own energy usage and will improve the Company's management of the operation of the distribution grid.

Q. WHAT IS THE COMPANY'S CURRENT IMPLEMENTATION SCHEDULE FOR THE METER REPLACEMENT PROJECT?

A. Our budget contemplates beginning AMI meter installation in 2022, and completing the roll-out of AMI meters in 2023 with FAN implementation occurring approximately six months prior to AMI roll-out.

Q. HOW CERTAIN IS THE COMPANY WITH REGARD TO THE SCHEDULE FOR INSTALLING THE NEW METERS, THE FAN, AND OTHER RELATED COMPONENTS AND INFRASTRUCTURE?

A. The Company contemplates that the schedule set forth above may be delayed. Unfortunately, like many other vendors and manufacturers, vendors for this project face supply chain problems, including with respect to computer hardware components. As a result, the Company currently estimates that AMI and FAN installation may be materially delayed. Xcel Energy is in regular communication with vendors and the Company anticipates that it may need to update the schedule set forth above.

Q. WHAT IS THE COMPANY'S FORECASTED INVESTMENT FOR THESE INVESTMENTS?

A. The Company's currently forecasted total investment in the allocated to the South Dakota jurisdiction for the Meter Replacement project is provided in Table 5 below.

Table 5

Meter Replacement Capital Additions

NSPM- SD Electric (Dollars in Millions)

	2019	2020	2021	2022	2023	2024	2025	Total
AMI	0.10	-	-	8.62	11.51	0.15	-	**20.38**
DI	-	-	-	1.56	-	-	-	**1.56**
FAN	0.03	0.13	0.49	0.51	0.47	0.47	0.05	**2.15**
Total	**0.13**	**0.13**	**0.49**	**10.69**	**11.98**	**0.62**	**0.05**	**24.09**

*Subject to rounding differences.

B. Customer Experience Considerations

Q. HOW WILL METER REPLACEMENT ENHANCE THE CUSTOMER EXPERIENCE COMPARED TO TODAY'S DISTRIBUTION SYSTEM?

A. With the AMI meters, DI, and the other components, the Company will be able to analyze and provide data and information that is simply not available with our current system and AMR technology. This is not just an incremental step compared to the data provided by our current metering and distribution system technologies; rather, the project will allow the Company to provide vastly different information with a level of granularity that can impact customers' energy usage decisions, as well as increase reliability and improve the safety and security of the grid.

Q. CAN YOU SUMMARIZE HOW EACH OF THE ELEMENTS OF THE METER REPLACEMENT PROJECT WILL IMPACT THE CUSTOMER EXPERIENCE?

A. Yes. Each of the core elements (AMI, the FAN, and DI) adds to the customer experience in a specific way, but each is also interdependent upon the others to ensure that maximum benefits can be realized.

AMI and DI allow us to provide the more granular and useful data that will enable an improved customer experience. Customers will be able to access timely and detailed energy usage data through web and mobile applications. Customers will be able to better manage their energy use and will be empowered to control costs.

AMI also provides outage information. The meters will send a "last gasp" message when an outage occurs. These messages are organized to inform our operators where the outage(s) exist, which can improve our response to outages. Then, when power is restored, the meters can verify the customer is back in service, which allows us to send accurate notifications to customers about the resolution of an outage.

The FAN is a wireless communications network that includes a mesh network and a communications network that connects the mesh network to back office applications. The primary function of FAN is to enable secure and efficient two-way communication of information and data between the AMI meters and field devices to other systems.

Q. WILL CUSTOMERS EXPERIENCE ANY OTHER CHANGES AFTER RECEIVING AN AMI METER?

A. Yes. After a customer receives an AMI meter, their bill will no longer include "Current Reading" and "Previous Reading" values. Today, monthly customer bills are calculated using an "incremental" approach—usage for each billing period is calculated by subtracting the previous meter reading from the current meter reading. This is a common legacy energy billing practice for customers on kilowatt-hour (kWh) consumption only (i.e., non-demand) rates, and relies on very basic meter functionality that registers usage in "increments" through use of analog dials or digital measurement of each kWh used. These readings occur approximately once each month and result in customers being billed for the kWh used over the course of the billing period.

As we transition our customers to smart meters, we are programming our systems to base customer bills on usage during multiple "intervals" – generally 15 minutes – recorded by the smart meter during the month. With the communication capabilities afforded by systems such as the Company's FAN, the AMI meters will transmit the information to our systems to calculate bills using the interval data. This means that our bills to customers will rely on the sum of the usage intervals over the billing period and will no longer be based on comparing consecutive meter readings at the end and beginning of a billing period. Our billing cycles will not change, but the "Meter Reading Information" section on customer bills will include an "actual" usage type. Figures 1 and 2 below show examples of the current and future "Meter Reading Information" section of a customer's bill.

Figure 1: Current Meter Reading Information Section

	METER READING INFORMATION		
METER 1234567			Read Dates: 04/05/20 – 05/04/20 (29 Days)
DESCRIPTION	CURRENT READING	PREVIOUS READING	USAGE
Total Energy	00000 Actual	00000 Actual	000 kWh

Figure 2: Proposed Meter Reading Information Section – Post-AMI Meter Installation

METER READING INFORMATION		
METER 1234567		Read Dates: 04/05/20 – 05/04/20 (29 Days)
DESCRIPTION	USAGE TYPE	USAGE
Total Energy	Actual	267 kWh

Q. HOW WILL THE COMPANY COMMUNICATE THIS CHANGE TO CUSTOMERS?

A. In general, the change to interval billing and bill presentment will occur on a phased basis, as each customer receives their AMI meter. Customers will have access to information explaining the change and an illustrative example of how their bill will look. We will provide information to customers about where to access an explanation of the change to interval billing and the Meter Reading Information section of their bill. As described further in the Direct Testimony of Company Witness Mr. Nicholas N. Paluck, the Company has submitted proposed modifications to the standard customer bill forms in Section 8 of the South Dakota Electric Rate Book to reflect this change.

C. Operational Considerations

Q. ARE THERE OPERATIONAL CONSIDERATIONS SUPPORTING THE DEPLOYMENT OF THE NEW METERS AND OTHER TECHNOLOGIES?

A. Yes. This project gives us increased visibility into the distribution grid, allowing us to operate the grid and detect faults and outages in real-time or near real time. This will allow us to (1) reduce the occurrences and durations of electric outages; (2) optimize the use of the existing distribution grid and enable the installation of field-based devices and applications with which to better operate the system; and (3) manage the distribution grid as it migrates from one-way power flows to a dynamic, two-way grid.

Q. WHAT DO YOU MEAN BY VISIBILITY?

A. When I mention visibility, I mean the Company's ability to know what is happening on the distribution system. These investments will give the Company the ability to obtain information regarding the secondary system and the meter at the customer's premises.

Q. HAS THIS PRE-PROJECT LEVEL OF VISIBILITY ALLOWED THE COMPANY TO PROVIDE RELIABLE SERVICE?

A. Yes. As I previously discussed, we have been improving our reliability metrics in South Dakota and we provide reliable service for our customers. However, there are limitations. Although, we have been able to successfully operate the system for many years, advancements in technology can now support communications between the intelligent devices deployed across the distribution system—up to and including meters at customers' homes and businesses. These advanced applications cannot be supported with the Company's aging meters, field equipment, and communication network.

Q. WHAT IS THE IMPACT TO THE OPERATION OF THE SYSTEM AND THE CUSTOMER EXPERIENCE OF VISIBILITY THAT EXTENDS ONLY TO THE SUBSTATION LEVEL?

A. The Company has traditionally had little insight into the customer experience – the voltage that the customer is receiving, whether the power is out or has been restored, or any abnormality that might be detectable and potentially lead to larger reliability issues.

Q. HOW DOES THIS IMPACT OUTAGE RESPONSE?

A. Since we have not had visibility into the system beyond the substation level, we have traditionally relied on customers notifying us of outages via phone, website, or smartphone app. Our Outage Management System then aggregates the outage call information and determines which portion(s) of the distribution system lost power. Once we know the portion of the system that is out, we must patrol the lines to find the source of the problem. This increases the time and expenses associated with responding to outages and leaves our customers without power for longer periods of time.

Q. HOW WILL THE METER REPLACEMENT PROJECT IMPACT OUTAGE RESPONSE TIME?

A. The Company can use the information from the advanced meters to pinpoint the location of the outages and deploy our teams to those specific portions of the distribution system.

D. DI

Q. YOU DISCUSSED DI BRIEFLY ABOVE, PLEASE PROVIDE ADDITIONAL DETAIL THIS CAPABILITY OF THE NEW METERS.

A. The Company has selected the Riva 4.2 meter manufactured by Itron Inc. Each of these AMI meters contains, in addition to metering components, a computer processor, RAM memory, flash memory, and a Wi-Fi radio. The result is the equivalent of a small computer located within each meter. Using these new capabilities, the Company plans to process and analyze detailed data collected by the meters in new ways that empower our customers and improve the operation of the distribution grid.

Q. PLEASE EXPLAIN THE BENEFITS OF THIS ON-METER COMPUTING CAPABILITY.

A. Generally, the Company's computer processing capabilities are centrally located. Consequently, any data that is collected by the meters and which the Company wishes to analyze has had to be transmitted to the back-end systems for processing. To take the most obvious example, energy usage information is collected and transmitted to the back-end where processes running on Company-owned servers analyze it and combine it with other information, such as addresses and rates, to create monthly customer bills. This paradigm has worked well for a number of years and will continue to be used. However, bandwidth limitations do not allow the Company to analyze more granular information from the meters.

Q. HOW DO BANDWIDTH LIMITATIONS KEEP THE COMPANY FROM ANALYZING MORE GRANULAR DATA FROM THE METERS?

A. Modern meters can collect second and even some sub-second data. If that data is analyzed, it can provide insights into how the distribution grid is operating locally and how the customer is using energy within his or her home or business. However, it would be prohibitively expensive to construct and maintain a communications network capable of transmitting all that data back to the Company's more centrally-located computer systems. DI resolves this problem by allowing for some on-meter processing of data.

Q. WHAT ARE THE ADVANTAGES OF ON-METER DATA PROCESSING?

A. Software applications selected by the Company can analyze granular data on the meter and then transmit the results of that processing, rather than the granular data itself, back through the Company's communications network. This uses less bandwidth. At the backend, additional centralized processing can take place to create actionable insights and information for the Company and its customers.

Q. WHAT ADVANTAGES DOES THE WI-FI RADIO IN THE NEW METERS PROVIDE?

A. After appropriate secure authentication procedures, the Wi-Fi radio will allow a customer to directly connect the meter to their home area network (HAN), including Wi-Fi enabled home devices such as smart phones and tablets. This new communication pathway will allow customers to directly obtain data regarding their own energy usage.

Q. WHAT SPECIFIC PLANS DOES THE COMPANY HAVE FOR DI IN THE NEAR-TERM?

A. Working with vendors, the Company has been creating the hardware and software infrastructure to allow for use of the DI capabilities of the new meters. The Company plans to initially implement a limited number of customer-facing and grid-facing uses of DI. The initial customer-facing use cases are: an enhanced My Energy Connection mobile application and Energy Analysis. The initial grid-facing use cases are: High/Low Impedance Detection, Connectivity, and Electric Vehicle (EV) Detection.

Q. PLEASE PROVIDE MORE DETAIL REGARDING THE MY ENERGY CONNECTION MOBILE APPLICATION USE CASE.

A. This use case involves connecting customers to the meter located on their premises using Wi-Fi. The initial mobile application will allow customers to get kW and kWh reads directly from the meter. We expect this capability will initially appeal to our most energy conscious and technological savvy customers.

The basic functionality provided by this use case is an important building block. The deployment will give us ability to test internal systems to deploy DI applications and orchestrate the DI ecosystem, including software on the meter, as well as the back-end systems that enable a full solution. In short, other use cases, including the Energy Analysis use case discussed below, require connectivity into the home using Wi-Fi, all of which the HAN connection enables. Given the practical bandwidth limitations of any wide scale communications network such as the FAN, it is Wi-Fi that will allow the Company to provide truly real-time information to customers—and it is Wi-Fi that will eventually enable direct communication with a broader array of smart devices.

Q. WHAT IS THE ENERGY ANALYSIS USE CASE?

A. Using appliance disaggregation, the energy analysis use case will allow customers to see which appliances use the most energy and how that impacts their monthly utility bills. Sometimes referred to as "nonintrusive load monitoring," appliance disaggregation utilizing DI will involve the analysis of an overall usage signal in order to determine which appliances are in use and estimate the load attributable to each. Individual types of appliances have characteristic features, such as the manner in which they start up, that can be detected by examining second-level and sub-second data available through DI. Crucially, this analysis does not require that customers have smart appliances. Instead, a load disaggregation application running on the meter will perform on-meter analysis of the data gathered by the meter, which, when combined with further back-end processing, can provide reliable and detailed disaggregation information to customers.

Q. HOW WILL CUSTOMERS OBTAIN THE INSIGHTS FROM THE LOAD DISAGGREGATION?

A. A smartphone application, which will directly connect with the meter using Wi-Fi, will provide customers with near real-time disaggregated information regarding their energy usage and notifications designed to prompt changes in energy usage. The notifications and suggestions offered by the smartphone application can encourage the shifting or shedding of load during periods of peak demand. Those customers with smartphones who participate will be empowered to change their energy consumption behavior. The resulting changes in customer behavior will save our customers money on their monthly bills. In addition to that direct financial benefit for customers, the change in customer behavior facilitated by the energy analysis use case should lower the Company's costs due to reductions in peak demand and provide environmental benefits. Further, the capabilities developed by this use case will support EV Detection and can later be expanded upon to further improve our ability to encourage and incentivize the shedding and shifting of load.

Q. WILL LOAD DISAGGREGATION INFORMATION BE PROVIDED TO THIRD PARTIES?

A. No, not unless customers themselves provide such information or explicitly consent to have it shared. The Company will continue to maintain the confidentiality and privacy of customers' energy usage information, including insights developed using DI, consistent with its existing privacy policies.

Q. WHAT IS HIGH/LOW IMPEDANCE DETECTION?

A. This application monitors the health of connections and can detect certain deterioration of the energized conductors. Deteriorating or loose connections, as well as deteriorating conductors, tend to progress to failure over time, at which point the customer will experience a partial or complete outage. But prior to that point, customers can experience voltage fluctuations causing customer complaints due to light flicker or equipment malfunction. However, even if there are flickering lights or other signs of a developing problem, customers may not notice the signs or may not contact the Company if they do. An application running on the meter can take current and voltage meter data collected by the meter and analyze them to calculate the impedance; then, it can send an alert to our system if the impedance falls outside of a normal range or increases consistently, which are signs that a problem is developing. These alerts will provide early detection that will allow the Company to resolve issues before they become costly or dangerous. In addition, early detection allows the Company to resolve issues as part of scheduled maintenance work and can, therefore, eliminate the need for a field crew to be immediately dispatched in an outage situation, which ultimately will save O&M costs in rates.

Q. PLEASE EXPLAIN THE CONNECTIVITY USE CASE.

A. Knowing the precise location of the customer's premises and how it is connected to the grid is foundational to the Company's ability to plan and operate our system and to keep our customers better informed regarding outages. The mapping of customers to the system is maintained in GIS, which forms the basis for all of our system planning, operation, and modeling. Though we believe our current GIS information is fairly robust, we also know that gaps do exist—particularly with our secondary system data. These gaps exist because, with prior generations of connectivity model technology and historic use cases for the data, the Company did not have the capabilities nor the need to gather and maintain the scope and precision of system data required for a modern grid. As such, legacy manual mapping sources, which served as the basis of GIS data migration, did not contain secondary asset information or some primary system attributes that now are also needed. Today, however, we need that precision for efficient outage management, automated operations, Distributed Energy Resources (DER) interconnections, and future advanced grid capabilities.

To improve our asset data, the core DI application will leverage the meters' Power Line Carrier (PLC) communication devices to enable the meters to self-identify themselves to each other and form groups that we can compare with distribution transformer groupings, which are mapped in GIS. These comparisons will identify outliers that need correction. The benefits of grid-facing connectivity use cases are improved accuracy in outage management and notification, and improved accuracy in planning and operational modeling.

Q. PLEASE EXPLAIN THE EV DETECTION USE CASE.

A. When a customer first plugs in an electric vehicle (EV) at their premises, an extension of the same technology that enables the Energy Analysis use case discussed above could also be used to detect the presence of that EV. That can enable several important benefits for both the customer and the Company. From the Company's standpoint, it provides critical information regarding growing EV penetration on the system, allowing us to better manage and plan distribution operations for significant increased load and the resulting changing load dynamics. From the customer's standpoint, EV detection can provide a channel to introduce customers to programs and rates that best suit their budgets and needs.

Q. DOES THE COMPANY ANTICIPATE USING DI FOR USES OTHER THAN THESE FIVE INITIAL USE CASES?

A. Yes, we do. The use cases described above are those the Company is planning for initial deployment. DI is an emerging technology with great promise. We anticipate that the lessons the Company learns from deploying this first set of use cases and the technological capabilities of the uses themselves cases will enable additional, future uses of DI.

E. Rate Case Impacts

Q. WHAT METER REPLACEMENT PROJECT CAPITAL ADDITIONS DID THE COMPANY MAKE IN AND PRIOR TO THE 2021 TEST YEAR?

A. As noted in Table 5, above, the Company made South Dakota Meter Replacement project capital additions of $130,000 in 2019, $130,000 in 2020, and $490,000 in the 2021 test year.

Q. WHY ARE THERE CAPITAL ADDITIONS FOR CERTAIN TECHNOLOGIES BEFORE THOSE ASPECTS OF THE PROJECT ARE ROLLED-OUT IN SOUTH DAKOTA?

A. The wholesale replacement of customer meters and the implementation of distributed communication and computer processing systems are significant and complex projects. In advance of the large-scale physical installation efforts, the Company must undertake a variety of tasks including project management, planning activities, installation of back-end hardware, testing, use case development, and software development and implementation.

Q. WHAT ARE KEY DRIVERS OF CAPITAL ADDITIONS FOR THE PROJECT?

A. The largest portion of the capital additions will be the installation of the advanced meters. Of approximately $24.09 million in Meter Replacement project additions forecasted for South Dakota between 2019 and 2025, $20.38 million will consist of AMI costs. That aspect of the project involves installation of a significant number of individual devices. The additions through 2023 are known and measurable because they are specific, budgeted work for a project that is already in process.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE METER REPLACEMENT PROJECT?

A. I recommend that the Commission approve the capital additions for the Meter Replacement project, including the additions through 2021 and the 2022 and 2023 additions which are known and measurable.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission approve the Distribution capital investments and O&M expenditures presented in this rate case. These capital 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. The Meter Replacement investments will give customers greater information and control over their own energy usage while also promoting the reliability, efficiency, and security of the grid.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.