BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF,	)	**Case No. 21-00XXX-UT**
SOUTHWESTERN PUBLIC SERVICE COMPANY,	)	
APPLICANT.	)	

DIRECT TESTIMONY

of

CHAD S. NICKELL

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

June 4, 2021

Case No. 21-00XXX-UT
Direct Testimony
of
Chad S. Nickell

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AMI	Advanced Metering Infrastructure
C&I	Commercial & Industrial
ComEd	Commonwealth Edison
DER	Distributed Energy Resource
DI	distributed intelligence
FAN	Field Area Network
FLISR	Fault Location Isolation System Restoration
FLP	Fault Location Prediction
GBC	Green Button Connect
GIS	Geospatial Information Systems
GMR	Grid Modernization Rider
HAN	Home Area Network
IT	Information Technology
Itron	Itron, Inc.
kW	kilowatt
kWh	kilowatt hour

LBNL	Lawrence Berkeley National Laboratory
O&M	operations and maintenance
OMS	Outage Management System
Plan	Customer Education Plan
PSCo	Public Service Company of Colorado
RF	radio frequency
RFP	Request for Proposal
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SPS	Southwestern Public Service Company, a New Mexico corporation
SCADA	Supervisory Control and Data Acquisition
WiSUN	Wireless Smart Utility Network
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services Inc.

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LIST OF ATTACHMENTS

Attachment	Description
CSN-1	Distribution Grid Modernization Capital Additions 2022-2025
CSN-2	Distribution Grid Modernization O&M Expenses 2022-2025
CSN-3	Distribution Grid Modernization O&M Expenses by FERC Account 2022-2025
CSN-4	Advanced Metering Infrastructure Summary of Request for Proposals
CSN-5	Customer Communications Plan

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I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Chad S. Nickell. My business address is 1123 West 3rd Avenue, Denver, Colorado 80223.

Q. On whose behalf are you testifying in this proceeding?

A. I am filing testimony on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS"), and wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy").

Q. By whom are you employed and in what position?

A. I am employed by Xcel Energy Services Inc. ("XES") as Advanced Grid Intelligence and Security ("AGIS") Delivery Lead for Distribution. XES is a wholly owned subsidiary of Xcel Energy and provides an array of support services to SPS and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. Please briefly outline your responsibilities as AGIS Delivery Lead for Distribution.

A. As the AGIS Delivery Lead for Distribution, I am responsible for managing the delivery of the AGIS projects for Distribution, which includes management of costs, schedule, and scope in partnership with Business Systems. This also includes supporting the AGIS governance structure for Project Management, Resource Management, and Financial Management. As the AGIS Delivery Lead for Distribution, I am responsible for managing the delivery of the AGIS projects for Distribution which includes management of costs, schedule, and scope in partnership with Business Systems. This also includes supporting the AGIS governance structure for Project Management, Resource Management, and Financial Management.

Q. Please describe your educational background.

A. I graduated from the University of Colorado, Boulder in May 2004, where I earned a Bachelor of Science degree in Electrical Engineering.

Q. Please describe your professional experience.

A. I joined Public Service Company of Colorado ("PSCo") in 2008 and have over 12 years' experience in the utility industry and have held previous positions as a Distribution System Planning Engineer and the Manager of Distribution System Planning and Strategy—South.

Q. Have you testified before any regulatory authorities?

A. Yes. I have testified before the Public Utility Commission of Colorado regarding PSCo's AGIS initiative.

Q. Are you sponsoring any attachments as part of your direct testimony?

A. Yes, I am sponsoring Attachments CSN-1 through CSN-5, which were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment CSN-1: Distribution Grid Modernization Capital Additions for 2022-2025;
- Attachment CSN-2: Distribution Grid Modernization O&M Expenses by Cost Element for 2022-2025;
- Attachment CSN-3: Distribution Grid Modernization O&M Expenses by FERC Account for 2022-2025;
- Attachment CSN-4: Summary of AMI Request for Proposals ("RFP") Results; and
- Attachment CSN-5: Customer Communications Plan.

II. PURPOSE AND SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support SPS's request for Distribution capital and operations and maintenance ("O&M") cost recovery for grid modernization components through SPS's proposed Grid Modernization Rider ("GMR"). To support this request, I provide an overview of the grid modernization components and the need for this initiative. I also explain and support SPS's proposed implementation of, and capital and O&M forecasts for, the Distribution grid modernization components.

Specifically, my testimony supports the prudence of Distribution's costs related to the Advanced Metering Infrastructure ("AMI"), Field Area Network ("FAN"), and Fault Location Isolation Service Restoration ("FLISR") grid modernization components that are planned at this time. Overall, my direct testimony supports SPS's request for cost recovery for these projects through the proposed GMR. I also discuss SPS's planned outreach efforts to help educate customers on what to expect from these grid modernization components and how the new functionality will benefit them.

Q. How is the technical discussion of the various grid modernization components divided between your Distribution testimony and Mr. Remington's Business Systems testimony?

A. Since most of the benefits of the grid modernization initiative reside at the Distribution level and the initiative supports the distribution system, I will provide the project overview and discuss the expected benefits of each component. I also provide primary support for the costs and implementation related to the AMI equipment, procurement and installation of FAN devices, and the procurement and installation of the intelligent field devices required for FLISR.

Mr. Remington will focus on the information technology ("IT") integration necessary to implement these components. While the grid modernization initiative is implemented in partnership with Business Systems, Business Systems has primary responsibility for implementing certain components. Where the Business Systems Business Area has primary responsibility for the component's implementation, I defer to Mr. Remington, as set forth in Table CSN-1 below.

Table CSN-1: Grid Modernization Witness Support

Component	Project	Witness
AMI	Meters and deployment	Nickell Direct
	IT Integration and head end application	Remington Direct
FLISR	Advanced application and field devices	Nickell Direct
	System development	Remington Direct
FAN	Installation of pole-mounted devices	Nickell Direct
	IT Integration and deployment	Remington Direct

III. OVERVIEW OF SPS'S GRID MODERNIZATION ACTIVITIES

Q. **What is the purpose of this section of your testimony?**

A. I provide an overview of SPS's grid modernization activities, of which the proposal in this case is a subset, and describe its purpose and principle components.

Q Please provide an overview of the grid modernization components.

A. Below is a brief overview of the grid modernization components:

- *AMI*: AMI meters are able to measure and transmit voltage, current, and power quality data and can act as a "meter as a sensor," allowing for near real-time[1] monitoring of the distribution system. These meters provide information about customer usage and will enhance SPS's ability to send price signals to customers, allow for new rate structures that will enable customers to manage their energy usage with near real-time energy usage data available through a customer web portal, identify outages without customer reporting, respond efficiently to metering and usage issues, and allow remote service connects, disconnects, and reconnects. AMI meters will replace existing (or "legacy") meters with more advanced technology to improve service and reliability.
- *ADMS*: Advanced Distribution Management System ("ADMS") provides an integrated operating and decision software and hardware support system to assist control room, field personnel, and engineers with the monitoring, control, and optimization of the electric distribution system. As further technology is rolled out, it will manage the complex interaction of Distributed Energy Resources ("DER"), outage events, feeder switching operations, and the advanced applications utilizing intelligent field devices, such as FLISR, discussed below. ADMS gives access to real-time and near real-time data to provide all information on operator console(s) at the control center in an integrated manner, which means the different operating systems and technologies will communicate with and update each other in the ADMS platform. ADMS is the fundamental platform that will utilize the updated data that is being gathered as part of the Geospatial Information Systems ("GIS") project (described below) and manages each of the other components described below.
- *GIS*: GIS is a geospatial project that provides location information about all physical assets that make up SPS's electric distribution system. The records also include specifications regarding the physical assets, such as a distribution feeder's size. While SPS already has a GIS, SPS has been engaging in a data gathering effort to validate and update the information in GIS because the ADMS model

[1] The term "near real-time" refers to the fact that there is a slight delay (under ten seconds) between the time the data is pulled and when it is received by the customer.

needs enhanced data accuracy to operate effectively. ADMS uses the GIS location and specifications to maintain the as-operated electrical model and advanced applications.

- *FLISR*: FLISR allows for the use of software and automated switching devices to decrease the duration and number of customers affected by any individual outage. These automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and restore power to unfaulted sections by closing tie switches to adjacent feeders as necessary. FLISR reduces the frequency and duration of customer outages. A subset application of FLISR, FLP, leverages sensor data from field devices to locate a faulted section of a feeder line and reduce patrol times needed to physically locate the fault.
- *FAN*: The FAN is the communications network that will enable communications between the infrastructure that already exists at SPS's substations, the the AMI software systems, the new AMI meters, and the new intelligent field devices associated with advanced applications such as FLISR. The FAN provides benefits to all grid modernization components, but is designed and built according to the needs of various specific components, and each has different communication network requirements.

Q. Is SPS seeking to recover costs associated with all of these components through the GMR in this proceeding?

A. No. In this case, SPS is only seeking to recover costs associated with AMI, FAN, and FLISR. However, I will discuss the other components to the extent they will facilitate the operation of AMI, FLISR, and FAN. The other components have independent utility and merit and SPS is proceeding with them irrespective of Commission action on the application in this matter.

Q. What is the overall timeline for implementation of AMI, FAN, and FLISR?

A. Implementation of AMI, FAN, and FLISR will occur over several years and be substantially complete by 2025. The implementation timeline is set forth in Table CSN-2.

Table CSN-2

Program	Implementation Timeline
AMI	Meter roll-out 2022-2023
FAN	Deployment 2022-2023 with optimization and support of FLISR in 2024 and 2025
FLISR	Deployment, integration, and testing 2023-2025

That said, the grid modernization effort is ongoing by nature, and SPS will continue to maintain the system as well as leverage evolving technology, platforms and optionality as appropriate over time.

Q. Did SPS consider alternatives to AMI, FAN, and FLISR?

A. Yes. SPS has considered alternatives for the various components of the grid modernization initiative. By that, I mean that SPS has not only considered options as part of overall strategic planning, but also compared options within that plan for each component and device through information gathering, vendor discussions, Requests for Information, Requests for Proposals, and vendor contract negotiations. With respect to the component-based alternatives, SPS has considered not only whether to move forward with AMI vs. Automated Meter Reading (as discussed by SPS witness Steven D. Rohlwing) or a FAN versus a cellular network, but also different types of AMI meters and systems, different device options, different functionalities, and different support and security considerations.

IV. SPS'S CURRENT DISTRIBUTION SYSTEM

Q. What is the purpose of this section of your testimony?

A. I will discuss the attributes of SPS's current distribution system as background for my discussion of AMI, FAN, and FLISR.

Q. How was SPS's distribution system originally designed, and how does this design limit the capabilities and operation of the system?

A. SPS's distribution system was originally designed to accommodate primarily a one-way flow of electricity and information from the utility to the customer with limited monitoring points. This design limits the amount of information and visibility that is available regarding the workings of the system and the customer experience beyond the distribution substation level. The system was also designed to operate through manual and local control configurations and lacks connectivity to easily share information between different portions and components of the system. These different system limitations can be categorized as:

- limited visibility;
- manual control; and
- limited connectivity.

A. Limited Visibility

Q. How does limited visibility beyond the substation impact operation of the system and the customer experience?

A. Since the existing distribution system only measures limited data on a small number of points on the system (primarily at substations), SPS is unable to view the flow of power, voltages, and the operation of equipment on the system beyond the substation. Thus, SPS is not able to specifically monitor the voltage that the customer is receiving, whether the power is out or has been restored, or any abnormality that might be detectable. To obtain information regarding the numerous distribution system components beyond the substation, such as meter readings, current flow, or voltage levels, SPS must send workers out into the field to gather this information.

Q. How does this limited visibility beyond the substation level impact SPS's ability to identify outages?

A. Since SPS has limited visibility into the system beyond the substation level, it relies on customers to initially notify SPS of outages via phone or website/app. SPS's Outage Management System ("OMS") then aggregates the outage call information and determines which portion(s) of the distribution system lost power. Once SPS identifies the portion of the system affected by the outage, SPS field personnel must patrol the lines to find the source of the problem. This increases the time and expenses associated with responding to outages and leaves customers without power for longer periods of time.

Q. How does this limited visibility impact SPS's ability to monitor and control voltage levels on the system?

A. Because SPS does not have visibility into the system beyond the substation level, it does not have insight into voltage issues on the system or the ability to efficiently manage the voltage level on the system. Similar to outage information, SPS relies on customers to report either high or low voltage issues. However, even after the issue is reported, it can take time to install monitoring equipment to help identify the source of the problem, which can be either on the utility side or the customer side of the meter. Similarly, this increases the time and expenses associated with responding to power quality complaints and the issues can persist for longer periods of time.

Q. How does the limited visibility impact the distribution system's ability to accommodate distributed generation?

A. SPS currently has limited visibility to measure the amount of distributed generation that is flowing onto or leaving the system. Rather, SPS relies on conservative estimates to quantify the amount of distributed generation entering and leaving the grid. Because SPS must ensure adequate voltage and protection at all times, conservative estimates, coupled with the inability to modify voltages or system configuration, can limit the accommodation of DER. This limited accommodation occurs because the output of distributed generation sources is highly variable and can lead to operational complexities, such as protection or voltage regulation concerns. For example, when high levels of distributed generation are on a feeder, protective equipment such as reclosers or substation breakers may not operate as intended because they are unable to differentiate between loads, distributed generation, and a system fault. The inability of protective equipment to operate as intended creates a risk that a faulted portion of the system would remain energized and present a hazard. It is important for the distribution system to have the capability to accommodate increasing levels of distributed generation as more distributed generation is added to the system.

Q. How does the limited visibility and information impact the customer experience?

A. The current meter reading system is limited to providing SPS with customer monthly energy usage information necessary to support customer billing. As a result, SPS cannot provide customers with timely power usage information to enable them to manage their electric usage more efficiently, nor can SPS provide customers with interval energy usage information over the course of the billing period. Additionally, the current meters do not have the capability to communicate information regarding outage or voltage issues to SPS. As a result, SPS relies on customers to report issues via phone or website/app.

B. Manual Control

Q. How does the limited number of remotely controlled devices beyond the substation impact operation of the system?

A. Operation of the current distribution system relies primarily on manual and local control schemes that require human intervention to complete an operation. For example, field switches for nearly all feeders are manually operated. If there is a fault on any feeder segment, the circuit breaker will open at the substation. When this occurs, a field crew has to patrol the feeder to find the location of the fault. This process can be time consuming, especially if visibility is poor or if sections of the line are not adjacent to roads. After the crew locates the fault, they manually open switches to isolate the faulted feeder section. Then, after the faulted section of the feeder is repaired, the switches are manually closed to restore service to the feeder. AMI and FLISR enable the automation of a portion of this process, which will reduce customer outage durations, enable quicker responses to faults, and reduce crew field time.

C. Limited Connectivity

Q. How does SPS currently communicate with substations, field devices, and meters and how will SPS's proposals in this application improve the current system?

A. For many years, SPS has communicated with its substations through leased telecommunications circuits with widely varying capabilities, especially in rural areas, or through expensive microwave installations. Connecting field devices (switches, etc.) and meters with communication networks has been limited to only a few very specific uses. Although SPS has been able to successfully operate the system for many years under these conditions, 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 improvements will allow SPS access to information to better manage the system and respond to outages, and to provide customers with access to near real-time data on their energy usage. Further, the continued increase of small-scale DER located on the grid edge (i.e., near or behind customer meters) has created a need for enhancements to accommodate these resources.

Q. Please describe SPS's vision for the future of the distribution grid.

A. SPS's vision for the future distribution grid is one that utilizes advances in technology to improve monitoring and operation of the grid for the benefit of customers. The implementation of AMI, FAN, and FLISR will provide SPS with timely and accurate information about what is happening on all portions of the grid, from substations down to each individual customer's meter. These investments will also provide the necessary information, automation, and intelligence to help SPS address problems more efficiently. In some cases, these insights will alert SPS to situations likely to result in an outage (such as overloaded equipment) before an outage occurs. The increased number of field sensors and devices will also provide SPS with the necessary information to continually monitor and make the necessary adjustments to the system to support increasing amounts of DER and other technologies such as electric vehicles.

Additionally, as discussed later in my testimony, the advanced grid investments will provide the foundation for new projects and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications for customers.

V. AMI OVERVIEW, COMPONENTS, AND IMPLEMENTATION

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I provide an overview of AMI and discuss SPS's plan to implement AMI.

A. Overview of AMI

Q. Please describe AMI.

A. AMI is an integrated system of AMI meters, communications networks, and software systems that enables secure two-way communication between customer meters and utilities' business and operational systems that enable benefits for both the customer and the utility. AMI meters are able to measure and transmit voltage, current, and power quality data and can act as a sensor, providing timely monitoring at the customer's point of service, which has a variety of uses for customers and business operations. AMI is a key element of grid modernization because it provides a central source of information that interacts with many of the other components.

Q. Please summarize the benefits of AMI.

A. AMI has the potential to benefit customers in many ways, including enhancing SPS's ability to operate the distribution system, providing new information and insights to customers, enabling new rate options, and facilitating new capabilities to further enhance the customer experience.

First, AMI meters provide substantial near real-time data that can be used to improve SPS's ability to monitor, operate, and maintain the distribution grid. AMI meters will be used to verify power outages and service restoration. Improved reliability monitoring leads to improved outage response, proper protection system analysis, and ultimately can help reduce the number of outages. AMI meters also provide improved voltage monitoring and management, support better load studies and analysis resulting in improved planning and design, and are used to support additional systems, such as ADMS.

Second, AMI will provide SPS and its customers access to timely, accurate, consistent, and granular energy usage data that is necessary to develop personalized insights and that supports informed decision making, including data such as 15-minute interval energy usage information. With these insights and other data, customers will be empowered to make energy usage decisions based on their preferences that can reduce their bills and enhance their lives and businesses.

Third, AMI meters are also able to support new rate designs that cannot be supported by SPS's current or "legacy" meters. Last, as further discussed in my testimony below, there is also a potential for the new distributed intelligence ("DI") capability of these meters to further enhance the distribution grid capabilities as well as the customer experience.

B. <u>AMI Meter Specifications and Components</u>

Q. Has SPS selected a meter vendor and an AMI meter?

A. Yes, SPS selected Itron, Inc. ("Itron") as the meter vendor and selected Itron's Riva Generation 4.2 AMI meter. The RFP process that was used to select this meter and vendor is described in greater detail below.

Q. What are the components of AMI meters?

A. The components of the AMI meter include: (1) the meter itself (responsible for measurements and storage of interval energy consumption and demand data); (2) an embedded two-way radio frequency communication module (responsible for transmitting measured data and event data available to backend applications and from meter to meter); (3) embedded DI capabilities (described below); and (4) an internal service switch (to support remote connection and disconnection).

Q. What are the functions of the AMI meter itself?

A. The primary purpose of the AMI meter is the same as SPS's legacy meters – to measure the amount of electricity used by SPS's customers for billing purposes. However, AMI meters have additional capabilities and can be remotely configured to measure bi-directional and/or time-of-use energy consumption in kilowatt hours ("kWh") and demand in kilowatts ("kW"). An AMI meter that is configured for bi-directional energy measurement measures energy provided by SPS to the customer and also measures net energy provided from customers (i.e., customers with solar panels) to SPS. Energy consumption data for billing purposes can be recorded by AMI meters in intervals as short as five minutes, or longer intervals if desired. The AMI meters also provide granular data regarding voltage and outages as explained further below.

Q. How often will AMI meters collect and transmit data to SPS?

A. The AMI meters will collect and transmit data to SPS a minimum of six times per day, or every four hours. However, there are several instances when the meters will communicate more often than every four hours. Some examples of this more frequent communication include:

- Individual meters can be read on an on-request basis. For example, a Customer Care call center employee may request and collect the meter data while on the phone assisting a customer.

- Through the customer portal, as described by Mr. Remington, a customer can access interval energy usage information and personalized insights that is developed from the granular energy usage data.

- Through the customer portal or smartphone application, as described by Mr. Remington, a customer can request an on-demand meter reading. This will provide a customer with near real-time energy information.

- AMI meters will transmit data when an event occurs such as a power outage, power restoration, power quality event, or a diagnostic event.

- AMI meters selected along the distribution feeders to provide data to ADMS will be configured for five-minute interval data and will transmit data to the head-end application every five minutes to make that information available to ADMS. The interrelation between AMI and ADMS is discussed further below.

Q. What are the other capabilities of the AMI meters?

A. In addition to the ability to measure, store, and transmit interval meter data, AMI meters also have the capability to:

- measure and transmit voltage, current, and power quality data;
- detect and transmit meter power outage and restoration events;
- detect and report meter tampering events;
- perform and transmit meter diagnostics pertaining to the correct functioning of the meter and communications module;
- support electric vehicle interconnections;
- support customer-facing energy conservation technologies (i.e., smart thermostats);
- support DI; and
- support remote connect and disconnect functions[2] for customers taking single-phase service (generally, residential and some small business customers).[3]

[2] SPS will continue to abide by the Commission's rules as well as SPS's tariff regarding the steps that will be taken prior to disconnection.

[3] The only AMI meters available in the marketplace with remote connection/disconnection switches are single-phase meters.

Q. What are the capabilities of the AMI meter's two-way radio frequency ("RF") communication module?

A. The RF communication module will utilize SPS's communication network (i.e., the FAN) to provide two-way communication between the meter and the AMI head-end application. The AMI head-end application is the operating system that is used to send data requests and commands to an AMI meter and receive data from the meter. These communications include:

- transmitting the measurements, alarms, and events performed by the meter to the head-end application;
- receiving commands from the head-end application to send specific meter measurements, alarms, and events, configure the meter to measure specific sets of energy parameters or time-of-use intervals and data recording intervals;
- remotely perform meter firmware upgrades; and
- receiving commands from the head-end application to open or close the internal service switch and communicate its status.

Q. Will the two-way radio module within the AMI meters have the ability to communicate with other devices?

A. Yes. While the primary purpose of the two-way radio is to capture and transmit customer billing data and service quality data from the AMI meter to SPS, there is also a second radio within the meter that is Wi-Fi compatible and can be configured to communicate with a customer's Home Area Network ("HAN") and devices.

Q. What is a HAN?

A. The HAN is a network contained within a customer's home or business that connects a customer's HAN devices together as well as to the customer's AMI meter. HAN devices can include thermostats, home security systems, energy display devices, and smart appliances. When connected through the HAN, these devices can communicate with each other to support energy management functions.

Q. How will customers be able to connect their HAN devices to the AMI meters?

A. The current AMI meter communication protocol allows HAN devices that are IEEE 2030.5 compliant (which includes Smart Energy Profile 2.0) to connect to the meter. SPS is in the process of reviewing other options with Itron for connecting HAN devices to the AMI meters. For devices that are compliant with the meter communication protocol, there is a two-step process that will involve customers submitting an activation request for their HAN devices and SPS processing that request and activating the appropriate components within the AMI meter to communicate with the customer's HAN device.

Q. What is Green Button Connect ("GBC")?

A. GBC is a web portal that allows customers to access usage information and provide it to third parties that can provide recommendations on energy consumption. The AMI meters will enable SPS to implement GBC through the Xcel Energy website.

Q. What is Distributed Intelligence?

A. Distributed intelligence or "grid edge computing" refers to the distribution of computing power, analytics, decisions, and action away from a central control point and closer to localized devices or platforms where it is actually needed, such as AMI meters or other "smart" devices on the grid. Since data does not need to be continually transmitted over the FAN, it reduces the strain on the network (for other uses of AMI and FLISR for example) and improves the computational speed, efficiency, and capabilities derived from these platforms.

Q. What portion of the HAN and DI costs are included in the costs that SPS is seeking to recover through the GMR?

A. The components in the meter that will support HAN and DI, including the microprocessor, memory and Wi-Fi radio, are integral parts of the AMI meters and these costs are included in the GMR. The additional costs for HAN and DI, including software applications and backend systems, are not included in the GMR costs. SPS anticipates future grid modernization filings that could include these costs or costs for future components that data shows are beneficial to SPS's customers.

Q. What is the purpose of the internal service switch that is contained within the AMI meters?

A. The internal service switch has the ability to remotely connect or disconnect power to the customer's electric service upon command from the head-end data application. SPS is not requesting any changes to its disconnection procedures as part of this proceeding.

Q. How did SPS determine the expected service life for the AMI meters?

A. SPS relied on information from an Ameren filing from June 2012 as a basis for determining the service life for the AMI meters, as this filing has been used as a standard for determining the service life for AMI meters by other utilities in subsequent years. With respect to meter depreciation, Ameren Illinois reviewed some of the largest AMI deployment plans in the United States, such as those by Duke Energy, Southern California Edison, DTE, and PG&E to as support for its estimated service life of 20 years for an AMI meter.[4] Other utilities following this approach include Consumers Energy

[4] *See* Ameren Illinois Cost-Benefit Analysis filed in Illinois Commerce Commission Proceeding No. 12-0244 (approved by Commission order on Dec. 5, 2012).

Company in Michigan, ComEd Illinois, Nevada Power, and ConEd New York.[5] SPS witness Mark P. Moeller discusses the depreciation rate for the AMI meters in greater detail.

Based on this information, SPS expects that the average service life for the AMI meters will be 20 years. As with any complex system, individual components may fail early or last longer than the average useful life. The AMI meter's useful life does not depend on when the first component fails or how long the last meter-module functions. Instead, its life depends on the system, as a whole, operating correctly and reliably. As these new AMI meters are computer-oriented and are integrated with large software systems, it is expected that these AMI meters will have a shorter service life than the current meters.

C. <u>AMI Deployment Timeline</u>

Q. Please describe the work that Distribution will undertake to implement AMI.

A. SPS plans to install approximately 120,000 AMI meters between 2022 and 2023. The Distribution Business Area is primarily responsible for the purchase, testing, and installation of these meters. Distribution will support the installation of the new AMI meters as well as removal, retirement, and disposal of the existing meters, but the installation and removal work will primarily be done by the meter vendor. Distribution will also test and configure all AMI hardware to ensure that it is working properly and is able to integrate with other products and applications.

[5] *See* Michigan Utility Commission May 14, 2015 order in Proceeding No. U-1765 (Consumers Energy Company); Illinois Commerce Commission June 11, 2014 order in Proceeding No. 12-0298 (ComEd Illinois); Nevada Public Utilities Commission July 30, 2010 order in Proceeding No. 10-03023 (Nevada Power); and New York Utility Commission March 17, 2016 Order in Proceeding No. 15-E-0050 (ConEd New York). However, utilities in other jurisdictions have also applied a depreciation rate based on a 15-year expected useful life for AMI meters, including Xcel Energy operating company Northern States Power Minnesota.

Q. What are the components of AMI deployment?

A. The deployment of AMI has two components: (1) meter deployment and (2) software deployment. The software deployment is discussed by Mr. Remington.

Q. When will SPS commence deployment of the AMI meters?

A. SPS anticipates that full deployment will begin in the fourth quarter of 2022 with the first AMI meter installation.

Q. Please provide an overview of the current AMI deployment timeline.

A. SPS plans to install approximately 20,000 AMI meters in 2022 and 100,000 AMI meters in 2023.

Q. With respect to AMI, what work will Distribution complete between the time of this filing and the start of the meter deployment schedule?

A. As I described earlier SPS selected Itron's Riva Generation 4.2 AMI meter, which is the same meter that will deployed in other jurisdictions across Xcel Energy. Xcel Energy will deploy the Riva 4.2 meters in Colorado first and began testing the Itron Riva Generation single-phase meter in 2020, focusing on the electric distribution and customer operational requirements. This meter testing included First Article Testing of the meter accuracy, and evaluation of the data sets from the meter through the meter reading and billing systems. First Article Testing is performed on meters containing the requirements and configurations, to ensure they meet all specifications as required by Xcel Energy. Integration Testing that examines business requirements and functionality across the products, applications, and platforms involved in the implementation of AMI, from meter to bill has been completed in Colorado and includes the assets that will be shared by SPS for the AMI deployment. The purpose of Integration Testing is to confirm that changes made within individual applications work correctly when tested together with changes made within individual applications. In addition and specific to SPS, as SPS configures rates within its billing system and any other requirements unique to SPS, SPS will follow a similar testing process prior to deploying meters. For commercial meters, two types of meters will generally be deployed, commercial meters with and without KYZ (wired connections from AMI meters that provide energy pulses to customer devices). Below is a timeline for commercial meters without KYZ. Commercial meters with KYZ will be available Q1 2023 for ordering and SPS will follow similar phases of testing for these meters.

Table CSN-3
AMI Poly Phase Testing Timeline

Scheduled Milestone	**Timeframe**
First Article Testing Poly Phase	4th Quarter 2021 to 1st Quarter 2022
Integration Testing Poly Phase	1st Quarter 2022 to 2nd Quarter 2022
Production Sample Test Poly Phase	3rd Quarter 2022
Start of AMI Meter Deployment	4th Quarter 2022

VI. FLISR OVERVIEW, COMPONENTS, AND IMPLEMENTATION

Q. What is the purpose of this section of your testimony?

A. In this section of my direct testimony, I provide an overview of FLISR and the benefits associated with this application. I then discuss the implementation plan for FLISR.

A. FLISR Overview

Q. What is FLISR?

A. FLISR is an integrated system that includes the advanced application within ADMS, a communication network, and automated field devices that enable automated switching devices to decrease the duration and number of customers affected by any individual outage. These automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and restore power to un-faulted sections by closing switches to adjacent feeders as necessary. FLISR reduces the frequency and duration of customer outages and improves utility performance metrics such as system average interruption duration index ("SAIDI") and the system average interruption frequency index ("SAIFI").

Fault Location Prediction ("FLP") is a subset application of FLISR that leverages data from field devices to predict a faulted section of a feeder line and reduce patrol times needed to physically locate a failure on the system.

Q. What are faults on the distribution system?

A. Faults are failures of the electrical system, which result in abnormal power flows. The distribution system is designed to detect such conditions and de-energize the affected portions of the system in order to limit damage and ensure safety. Faults can be either temporary or permanent. A permanent fault is one where permanent damage is done to the system and a sustained outage (greater than five minutes) is experienced by the customer. Permanent faults may be the result of insulator failures, broken wires, equipment failure (e.g., cable failure, transformer failure), and public damage (e.g., an automobile accident impacting a utility pole). Temporary faults are those where customers experience a momentary interruption (less than five minutes). Causes of temporary faults are transient in nature such as lightning, conductors moving in the wind, animal contact, and branches that fall across conductors and then fall or burn off.

Q. How does SPS's system currently identify faults and restore power for customers?

A. SPS has Supervisory Control and Data Acquisition ("SCADA") system capability at some of its substations that informs it of feeder and substation-level outages. When the outage does not impact a full feeder or where SCADA capability does not yet exist (common in rural systems), SPS must rely on calls from customers to inform SPS of an outage. SPS's OMS then aggregates the outage call information and determines which portion(s) of the distribution system lost power. The Control Center Operator then uses information from all current outages, prioritizes, and dispatches field personnel to start patrolling an area. Prior to ADMS, SPS did not have fault location prediction capabilities, which required crew to patrol a distribution line to find the location of the fault. This process can be time consuming, especially if visibility is poor or if sections of the line are not adjacent to roads and can require field crews patrolling several miles of distribution line before visually identifying the failure.

When crews identify the cause of the failure, they proceed to manually open switches to isolate the fault. Next, they manually close other switches to restore service to as many customers as possible. Finally, they repair the failure and restore power to the remaining customers.

Q. What is the outage time for a typical feeder-level fault?

A. The five-year average time to restore a feeder-level fault in SPS has been 85 minutes (not storm-normalized). SPS feeders serve, on average, 626 customers. I discuss the expected benefits of FLISR in more detail below.

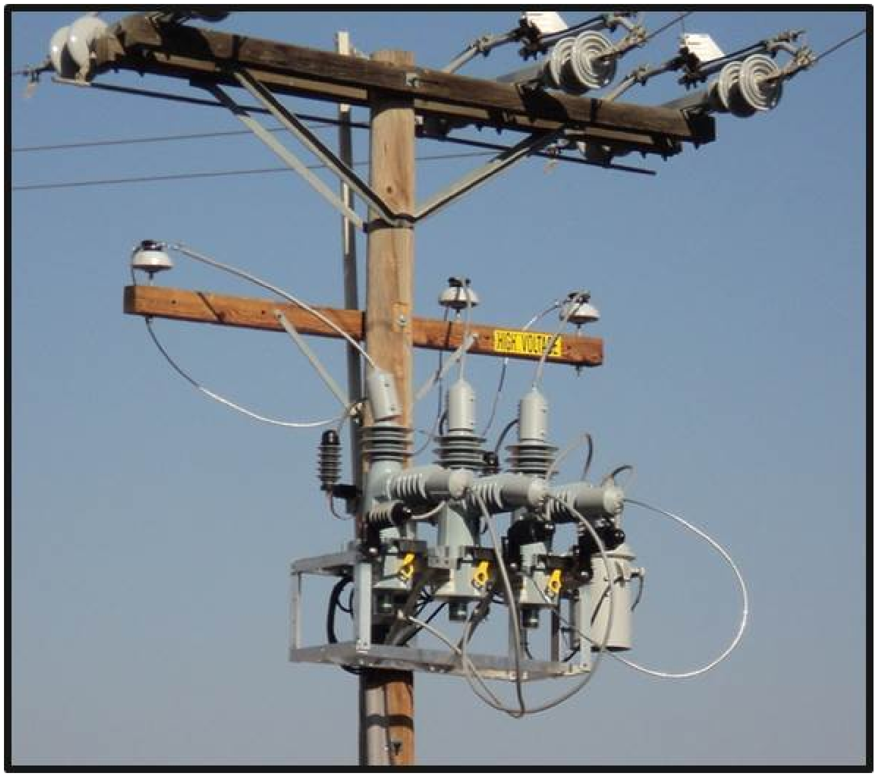
Q. What are the components of FLISR?

A. There are four principal components of FLISR: reclosers, automated overhead switches, automated switch cabinets, and substation relaying. The two main components to FLP are powerline sensors and substation relaying.

Q. What are reclosers and how do they operate?

A. Reclosers are pole-mounted reclosing and switching devices. SPS currently has reclosers on the distribution system, but only a few of these reclosers have communication abilities to enable remote operations capabilities. The new devices will perform the same functions of existing reclosers but have enhanced monitoring, communications, and control capabilities. The devices are able to identify and interrupt a fault event, then report the fault current to ADMS. ADMS can then use that information to execute FLP to determine the location of the fault. The reclosers will be able to "re-close" after a fault event to determine if a fault still exists. If the fault does not persist, the recloser will reclose and restore service. If the recloser determines that there is a permanent fault after multiple attempts to reclose, the device will communicate the fault information to ADMS, which will inform SPS of the need to dispatch a crew to the fault location. In addition, the reclosers will be controlled by ADMS when there is a permanent fault to automatically restore service. Figure CSN-1 is a picture of a recloser on a distribution pole.

Figure CSN-1



Recloser on Distribution Pole

Q. What is an automated overhead switch?

A. These switches are overhead remote supervisory sectionalizing and motor operated switching devices. When a fault occurs, a feeder breaker senses the fault and opens. Although the overhead switches do not communicate directly with the feeder breaker, local controllers on switches on both sides of the fault will sense the loss of voltage and open, isolating the fault. However, unlike a recloser, the overhead switches do not have the capability of reclosing to determine whether the fault is permanent in nature. Instead, overhead switches rely on the feeder breakers for the reclosing functionality. Although automated overhead switches lack the reclosing functionality, they are more compact and less expensive than reclosers, making them the preferred choice for space-constrained locations or where localized reclosing capability is not required.

Q. What are automated switch cabinets?

A. Automated switch cabinets are pad-mounted sectionalizing and switching devices. Each cabinet has motor-operated, remote-controlled devices that SPS will use for switching underground feeders. They will perform functions similar to the automated overhead switches for our underground feeders. Each cabinet has two or more switches inside, providing the safe and reliable switching capabilities required for FLISR.

Q. What is the function of the powerline sensors?

A. Powerline sensors are equipment placed on distribution lines to continuously monitor the grid and send information back to the utility for analysis and response. Sensors are available to measure such attributes as current, voltage, power factor, and faults. For FLISR specifically, this technology will allow SPS the ability to detect disturbances on the grid and use this information to identify fault locations, isolate faults, and analyze the unique patterns of these events to predict the likelihood of future outages. SPS hopes to leverage the equipment in the future to detect defective equipment before it fails.

Q. What is the function of the substation relays?

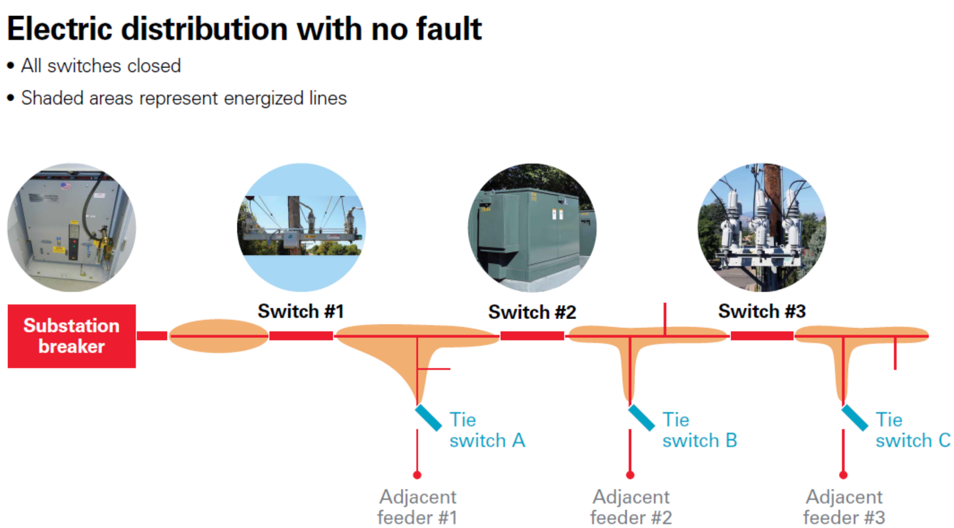
A. Substation-based relays, historically referred to as the feeder's overcurrent relays, provide the logic for when and why a breaker opens. The purpose of these relays is to monitor and, if warranted, to initiate commands to the feeder breaker to de-energize systems which have been compromised. This is to protect the public, utility personnel, and to minimize damage to public or private property or utility equipment. Modern relays are multi-functional and have multiple protection functions programmed into them. These relays can also capture important fault information which will be sent to ADMS for the fault location application.

Q. Please describe in more detail how FLISR operates in conjunction with ADMS.

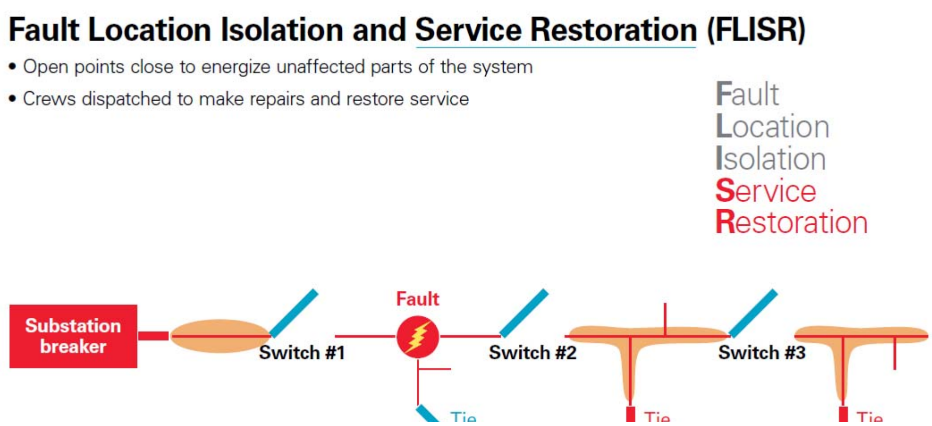
A. There are three basic steps to the operation of FLISR within ADMS. In the first step, when a fault occurs, the automated field devices will open, or sectionalize the feeder to isolate the fault. Depending on the devices and the situation, the device may attempt to reenergize (or "re-close") the affected area first, in case the fault was only temporary in nature. Once the fault is cleared (de-energized), data will be sent from those intelligent field devices to ADMS (over the FAN). ADMS will then run the FLISR application which will analyze the situation, select appropriate switching device near the fault, and generate a switching plan to restore service to other customers. In doing so, ADMS will consider not only device and feeder loading, but surrounding substation loading as well. ADMS will then execute the proposed switching plan and notify the operator of the need to send a crew to the isolated section to manually investigate the fault event. This process takes less than five minutes from the occurrence of an outage to operator notification. ADMS will also be able to run the FLP algorithm and predict which segment within a FLISR section the fault exists, which will reduce expected patrol times by crews. Figure CSN-2 below shows how FLISR isolates that impacted feeder section to restore power to other sections of the line.

Figure CSN-2

FLISR Feeder Configuration – Prior to Fault



FLISR Feeder Configuration – Service Restored



Q. How does FAN support the operation of FLISR?

A. FLISR will leverage the FAN for communication between the field devices and the ADMS system. Without FAN, ADMS would not be able to gather readings from the FLISR field devices or be able to remotely control these devices.

Q. How does AMI support the operation of FLISR?

A. Indirectly, the FLP component of FLISR considers outage prediction results from a separate outage prediction application in situations where multiple possible fault locations are indicated. The outage prediction application utilizes data from AMI meters. In this way, FLISR and FLP indirectly use AMI data when determining the location of an outage.

Q. Please describe in more detail how FLISR benefits customers.

A. Electric power outages and blackouts cost the United States about $44 billion annually, according to a 2018 study by Lawrence Berkeley National Laboratory ("LBNL").[6] The 2018 study by LBNL provides economic impact data per event based on the customer class (i.e., medium and large Commercial & Industrial ("C&I"), Small C&I, Residential) and the length of the outage.[7]

In addition, customer reliance on electricity has increased due to the rise of electrification, increasing customer service expectations imposed on the businesses and employees that use our electric service, and increasing overall expectations regarding power quality, number of outages, and outage length. Whether or not customers understand metrics like SAIDI, they expect reliable electric service from their electric utility.

For commercial and industrial customers, the impacts from reliability tend to more readily apparent as outages result in loss of production and loss of revenue. For

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6 *Improving the Estimated Cost of Sustained Power Interruptions to Electricity Customers* (June 2018), available at: http://eta-publications.lbl.gov/sites/default/files/copi_26sept2018.pdf.

7 *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*, available at https://emp.lbl.gov/sites/all/files/value-of-service-reliability-final.pdf.pdf. For instance, a one-hour outage would have an economic impact of $17,804 on a medium or large C&I customer, $647 on a small C&I customer, and $5.10 on a residential customer.

example, for many of the larger energy requests, such as oil and gas customers, electric reliability is typically one of the main considerations that is emphasized as essential to their operations. Being able to demonstrate a history and commitment to reliability make it easier to attract these types of customers, which in turn can bring jobs and economic development to New Mexico

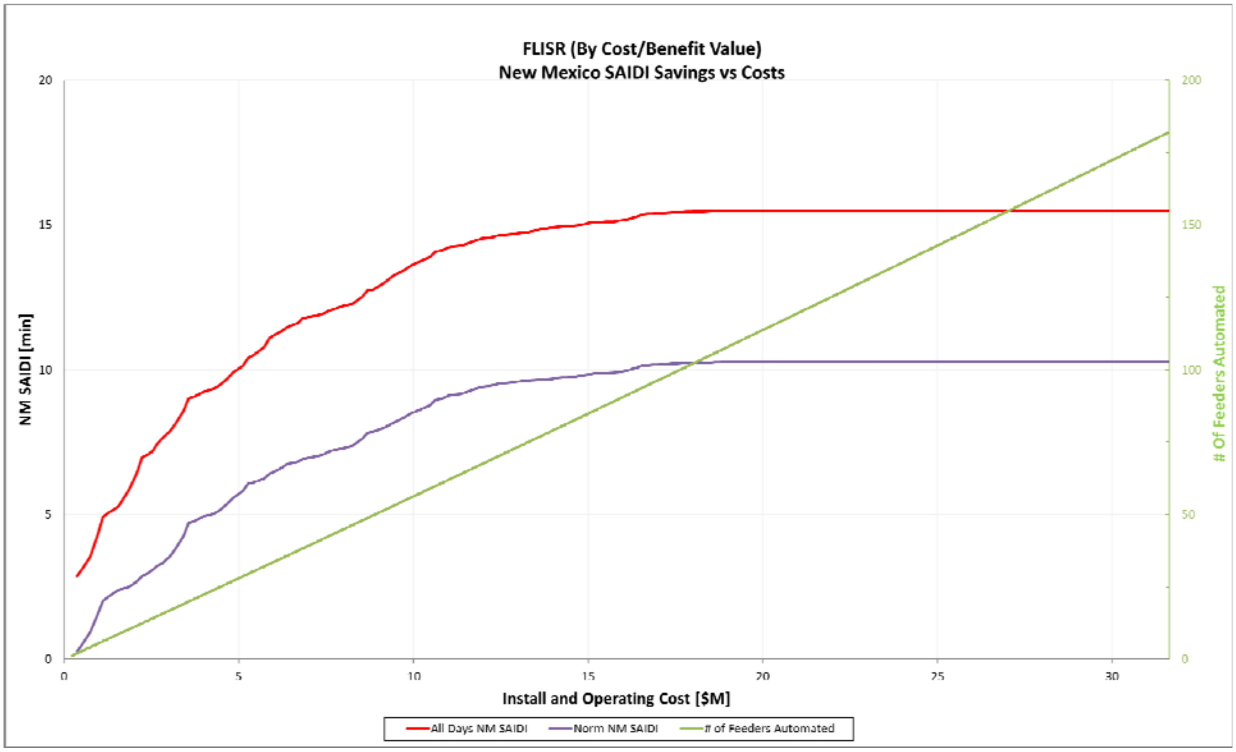
Q. How does SPS's reliability compare with that of peer utilities?

A. On an annual basis over the past five years, SPS has been in the first and second quartile when compared to its peer utiltities and, on average, customers have electric service more than 99.9 percent of the time. However, as reliability standards increase over-time and as other utilities implement more advanced technologies, SPS anticipates it may not maintain its position amongst its peers if it does not enhance its reliability performance through investments in FLISR.

Q. Does SPS intend to deploy FLISR on all of its distribution feeders?

A. No. SPS plans to install automated equipment on approximately 55 feeders, or approximately 8 percent of the feeders on SPS's distribution system. The deployment is based on the cost/benefit analysis summarized in Figure CSN-3 and is targeted towards areas that have lower reliability performance. As Figure CSN-3 illustrates, the reliability benefits decline as the level of FLISR investment increases. The highest level of benefits is provided by deploying FLISR on feeders with the greatest number of outages and customers. In addition, the deployment will include feeders that will have full FLISR capabilities enabled and feeders that have a subset of FLISR functionality or fault location prediction capabilities enabled. Fault location prediction capabilities will be enabled in areas where it is not possible or practical to enable full FLISR capabilities.

Figure CSN-3



Q. Please describe in more detail why it may not be cost effective to deploy FLISR on all feeders.

A. Some of the areas of SPS's system already have extremely high reliability and, in some cases, it may be many years between outages, where others may be more susceptible to outages and storm-related events such that FLISR will offer reliability improvements. For instance, approximately 34 percent of SPS's feeders have not had any mainline outages from 2015-2019, and around 73 percent of SPS's feeders have averaged less than one mainline outage per year from 2015-2019. The remaining feeders on SPS's distribution system have had a higher number of outages. With respect to those feeders, FLISR can reduce the number of customers impacted by a fault and the time to restore power for customers as I described previously. In addition, as with all the investments SPS makes, SPS evaluates the costs and benefits of enhancing the experience for customers. FLISR is one of the most cost-effective ways for improving reliability for customers.

Q. Will SPS deploy FLISR to only those circuits with lower reliability performance?

A. No. While the deployment will target areas that have historically had lower reliability performance, SPS will also consider opportunities to utilize existing compatible substation and field devices that can enable FLISR and FLP capabilities, which avoids the cost of deploying a new substation or field device. In addition, the deployment of devices and enablement of feeders will be grouped in geographic areas to gain operational and reliability benefits which will include some feeders that have had historically higher reliability performance.

B. <u>FLISR Deployment Timeline</u>

Q. What work will the Distribution Business Area undertake to implement FLISR and FLP?

A. The FLISR and FLP devices are on a three-year deployment schedule that will begin in 2023. The deployment priority will be based on the historical reliability performance of the feeders. Deployment of devices and enablement of feeders will be grouped in geographic areas to gain operational and reliability benefits. Distribution will be responsible for managing the engineering, procurement, and installation of the physical devices that will enable the FLISR and FLP advanced applications. This work will be done in combination with internal labor and third-party contractors.

Distribution will also be responsible for the system analysis to determine the appropriate placement of the field devices described above. It will also be necessary to complete make-ready work to install these devices, such as reconfiguring the location of a pole to allow a device to be placed on that pole or reconfiguring an underground cable so that a pad-mounted piece of equipment can interconnect with it.

Q. Please describe the different steps involved in enabling FLISR.

A. SPS is taking a multi-step approach to FLISR in New Mexico. The first step involves deployment of protective equipment that can be leveraged with local programming to reduce outage exposure for customers. Second, this equipment will be enabled with FAN communications and those devices will report information about faults to the ADMS. That information will be leveraged to dispatch field crews directly to a fault as opposed to manually patrolling a distribution line, thereby reducing outage durations for affected customers ('Fault Location Prediction'). Third, ADMS will provide Control Center Operators information about a fault and possible restoration scenarios. Control Center Operators will use this information to remotely operate the automated field devices ('Open Loop FLISR'). Finally, the ADMS will automate execute those restore service after a fault without requiring action from a Control Center Operator ('Closed Loop FLISR').

Q. Are different steps required for feeders that do not have FLISR capabilities?

A. No. As I described earlier, in areas where it is not possible or practical to enable full FLISR capabilities, a subset of FLISR functionality or fault location prediction capabilities will be enabled. Enabling FLP capabilities requires the first two steps I describe above.

Q. What work will SPS perform between now and 2025 to implement FLISR?

A. SPS plans to deploy FLISR field devices at a relatively steady rate through 2025, which as I described above includes multiple steps for implementing FLISR, including enabling

FAN communcations and integrating the field devices with ADMS. The field device installation rate is shown in Table CSN-4 below. By the end of 2025, FLISR devices will be installed on approximately 55 feeders, benefiting nearly 34,000 customers. As I described above, SPS currently does not have plans to deploy FLISR on all feeders as some feeders already have extremely high reliability and SPS's cost/benefit analysis showed diminishing benefits to customers beyond the proposed funding level for the FLISR project.

Table CSN-4
FLISR Field Device Installation

FLISR Field Devices	2023	2024	2025
Field Devices	53	69	44
No. of Feeders	17	23	15

VII. FAN OVERVIEW, COMPONENTS, AND IMPLEMENTATION

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I provide an overview of FAN and discuss SPS's plan to implement FAN. The implementation of FAN is a joint effort with Business Systems. Mr. Remington discusses the IT aspects of FAN in his direct testimony.

A. Overview of FAN

Q. What is the FAN?

A. SPS's FAN will be a resilient wireless communications network that will provide connectivity and enable two-way communications between the existing infrastructure and new and planned field devices up-to and including the customer meter.

Q. What are the components of the FAN?

A. The FAN will consist of two separate wireless technologies: (a) a lower-speed private WiSUN mesh network, and (b) a high-speed network to connect the WiSUN mesh network to the WAN. This network will primarily consist of public Long Term Evolution ("LTE") cellular service, supplemented by alternatives such as microwave or fiber where public LTE service is unavailable.

Q. How will the FAN operate?

A. The FAN will be a single, general-purpose, wide area wireless networking resource that will be capable of simultaneously accessing diverse types of endpoints, each with its own performance requirements on SPS's electric system. These endpoints will include a variety of field devices, including reclosers, feeders, electric meters, capacitor banks, and virtually any other field device capable of communications. These endpoint devices also participate in the FAN mesh network by providing connectivity and act as repeaters.

Going forward, FAN will be able to communicate with other endpoints as new devices are installed or existing devices are upgraded with communications modules.

Q. What are the components of the FAN network?

A. As noted, the FAN is a highly secure, wireless network. The equipment consists of cellular modems, access points, and repeaters. Access points link the endpoint devices to the communications network and extend the reach of the communications network. Repeaters are range extenders and are used to fill in coverage gaps where devices would be otherwise unable to communicate. These devices will be deployed in strategic locations to pick up signals from field sensors that are then fed to cellular.

Q. Why is the FAN necessary?

A. A communications network is required to support the deployment of AMI meters and FLISR field devices and will facilitate the operation of advanced grid applications in the future. Deploying devices that can improve distribution system operations without the FAN would be considerably more expensive to install and operate and would limit SPS's ability to gain full value from their capabilities.

Implementation of the FAN will also provide reliable communication capabilities to all participating field devices, regardless of the device's use. Therefore, the FAN will provide the same, reliable communication to multiple business application and devices.

B. FAN Deployment Timeline

Q. What work is Distribution undertaking to support the installation of the FAN?

A. The implementation of FAN will be a joint effort between Business Systems and Distribution. Distribution will be responsible for installing the FAN devices (primarily access points and repeaters) that will be located on distribution poles. Business Systems will be responsible for the design of the network systems for WiSUN, the security of these networks, and configuring the software and hardware components of FAN.

Q. How will Distribution install the FAN devices?

A. The access points and repeaters will be mounted primarily on distribution poles to provide adequate height for the radio signal to propagate. In certain instances, the distribution pole will need to be modified or replaced to support a particular device and Distribution will be responsible for completing this modification or replacement. In areas where SPS has underground service, arrangements will be made to mount the devices on street lights or other structures with appropriate height.

Q. Please explain how FAN will be deployed.

A. As discussed by Mr. Remington, the WISUN portion of the FAN is being implemented in a three-phased approach. Xcel Energy engaged in comprehensive planning for implementation of the FAN beginning in 2016.

The first phase of the implementation of the WiSUN portion of the FAN was the design phase to select the WiSUN device vendor and to site potential locations for the WiSUN device. This phase was completed in 2018.

Phase II of the WiSUN FAN implementation involves site surveys to inspect each location identified in the design phase to evaluate its suitability for a WiSUN device.

These inspections confirm that SPS can receive the appropriate signal anticipated in the design phase at the height and location on the pole where the device will be located.

In Phase III, Distribution field crews will install the devices at locations identified in Phase II. Once devices are installed, they will be tested, and thereafter monitored by Xcel Energy's Integrated Network Operations Center to ensure they are operating as expected. Public LTE devices will be installed concurrently with the WiSUN components. The FAN implementation activity will begin in early 2022 and primarily continue into 2023, driven by the need to build out the FAN approximately six months in advance of the deployment of AMI meters. In addition, SPS has capital expenses beyond 2023 as part of optimizing the mesh network and adding additional FAN devices once AMI is fully deployed and as part of supporting FLISR field devices. Further details regarding the implementation of FAN are discussed by Mr. Remington.

VIII. THE IMPLEMENTATION OF AMI, FAN, AND FLISR PROMOTES GRID MODERNIZATION, PROVIDES BENEFITS TO SPS AND ITS CUSTOMERS, AND IS IN THE PUBLIC INTEREST

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I will describe how the implementation of AMI, FAN, and FLISR benefits customers, is in the public interest, and provides a net public benefit because it will: promote grid modernization, improve the efficiency, reliability, resilience, and security of SPS's system; allow SPS to maintain reasonable operations, maintenance, and customer costs; improve SPS's ability to develop programs that promote clean and renewable energy; support a flexible, diversified, and distributed energy portfolio; and improve SPS's abilty to provide product and program offerings to customers.

In the sections below, I separately discuss the benefits of AMI and FLISR. I do not discuss FAN directly since it is not a standalone program and does not provide benefits on its own. Rather, FAN enables AMI and FLISR functionality by providing secure and efficient two-way communication of information and data between the AMI meters and FLISR field devices to the supporting software systems.

A. The Benefits of AMI

Q. Please summarize how AMI will improve electrical system efficiency, reliability, and operations.

A. As discussed previously in my testimony, SPS currently has limited visibility into the distribution grid and relies on customers to notify it of issues that include outages. When responding to incidents, SPS must send workers out into the field to locate the source of the problem. This increases the time and expenses associated with responding and leaves customers without power for longer periods of time.

AMI will benefit the operation of the grid and customers in many ways, including improved system efficiency, reliability, and operations. I will specifically describe the following benefits:

- improved distribution system management efficiency;
- improved outage management efficiency;
- improved outage management during storms;
- reduction in field and meter services; and
- improved efficiency in distribution maintenance.

Q. What distribution system management efficiencies will be gained as a result of AMI?

A. AMI will provide a wealth of information about the workings of the distribution system. This AMI data can be aggregated at various levels of the distribution system, including tap, transformer, and service lines amongst other distribution system equipment. SPS will use this data to prioritize distribution grid improvements and more efficiently plan and design the system. Through the aggregated AMI data, SPS will have greater insights into the nature of the load - specifically load profiles, which will help SPS evaluate risk. The voltage insights will help SPS prioritize areas for investments in tap, transformer, and secondary wire replacement. For instance, the AMI data can be aggregated at the transformer level to identify overloaded transformers and determine the optimal transformer for replacement transformers.

Q. Please explain how the installation of AMI meters will improve efficiency in outage management.

A. AMI will enable increased outage management efficiencies by transmitting automated outage notification and restoration confirmation to SPS, providing SPS with an expeditious and more accurate scope of an outage. This automated outage information will assist SPS in restoring power more quickly by providing more detailed outage location information that will reduce the time and expense in locating the outage. Overall, because of these increased outage management efficiencies, AMI enables quicker response and restoration to customer outages, which ultimately improves reliability.

Q. How will AMI improve outage management during storms?

A. AMI enables an automated outage information system that will allow SPSto deploy crews more efficiently to outage areas, especially during storm outages, ensuring that all customers in an area have been restored before dispatching the crew to the next location. This also will reduce outage impacts to customers and improve reliability.

Q. What types of field and meter service will be reduced by implementing AMI?

A. Since AMI meters will have the ability to provide billing, power, and voltage information to SPS on command, there will be a reduced need to send personnel to the field to gather this information. This will result in more efficient operations in several areas:

- *Reduction in Outage Trips due to Customer Equipment Damage*: SPS's current meter system requires crews to be dispatched to verify outages. Sometimes these outages are due to damaged customer equipment and not utility damaged equipment. Under the new AMI system, AMI meters will have two-way communications to the meter, and SPS can verify whether there is power at the meter thus pointing to a likely customer problem. This would help reduce field trips while also assisting customers in identifying the likely cause of the outage.
- *Cost Savings from Remote Connect Capability*: AMI enables remote connection and disconnection of residential type service without the need to dispatch crews. This will result in personnel and transportation cost savings due to the reduction in field visits.

- *Reduction in "Ok on Arrival" Outage Field Visits*: AMI will allow SPS to test for loss of voltage at the service point and detect both outage conditions and to know when restoration is complete. As a result, AMI implementation will help eliminate unnecessary field trips to customer premises that result in field personnel finding no electric service issues upon arrival.
- *Reduction in Field Visits for Voltage Investigations*: When notified of a potential voltage problem, SPS currently sends a technician to investigate. AMI enables the elimination of unnecessary trips when proper voltage can be verified remotely, and helps SPS prioritize and dispatch the most appropriate crews if the voltage is outside of the appropriate range.

Q. Will the benefits described above help SPS maintain reasonable operations, maintenance, and customer costs?

A. Yes. In addition to improving system efficiency, reliability, and operations, the benefits described above will provide quantifiable benefits that are included in the cost benefit analysis discussed by Mr. Rohlwing.

Q. Will other benefits of AMI help SPS maintain reasonable operations, maintenance, and customer costs?

A. Yes. In addition to the benefits described, other quantifiable benefits include:

- avoided manual reading services;
- avoided meter purchases;
- remote connect and disconnect capability;
- reduced consumption on inactive meters;
- reduced uncollectible/bad debt expense; and
- reduced theft/meter tampering.

Q. Please describe the avoided manual reading services benefit.

A. SPS's current meters require it to send workers out into the field to manually read meters for billing purposes. This increases the time and expense for providing billing services to customers. AMI meters will have the ability to automate the billing process so there is no need to send workers to the field to gather this information.

Q. Please describe the avoided meter purchase benefit that will result from deployment of the AMI meters.

A. AMI meters will have a lower failure rate as compared to SPS's existing meters. As a result, there is a cost savings associated with not having to replace these failed meters. The benefit from avoided meter purchases, however, is partially offset by the cost of ongoing replacement of AMI meters due to normal failure rates.

Q. Please describe the remote connect and disconnect capability benefit.

A. AMI meters have remote connect and disconnect capabilities. The ability to remotely connect or disconnect service, when paired with customer protections, provides both cost and convenience benefits. When a customer wants to start service at a single-phase premise today, a field visit is necessary. This involves a fee for the customer and requires someone to be present at the location to meet an SPS representative. With remote connection capability, a customer would not need to be present and a lower fee could be charged.

Remote capabilities could also be beneficial for seasonal disconnections, where a customer may want electric service disconnected for a lengthy period of time because a home is unused. Instead of incurring the cost for two field visits to disconnect and reconnect service, a customer could schedule a remote disconnection and reconnection aligned with occupancy needs. This would save customers money through reduced fees and energy usage and would be more convenient.

There would also be benefits when changes in tenants occur. AMI remote disconnection will enable SPS to disconnect electric service between tenants if there was no landlord agreement in place. Today, it is typically cost prohibitive to disconnect the account given the expense to send employees into the field. Remote disconnection and reconnection can also help reduce the cost of an unoccupied retail location for a building owner who has a vacant property that is between tenants.

Q. Please describe the reduced consumption on inactive meters benefit.

A. This benefit is related to electric consumption during a gap between two separate user accounts and the process to disconnect and connect service between tenants or owners. With the remote connect/disconnect capability, usage on inactive meters should be reduced.

Q. Please describe the reduced uncollectible/bad debt expense benefit.

A. Due to the manual nature of the existing disconnect process for non-payment, SPS is not able to complete all the physical disconnections for non-payment orders issued in a given year. Utilizing the remote connect/disconnect capability of the AMI meters should result in more timely disconnection for nonpayment, which should reduce bad debt expense.

Q. Please describe the reduced theft/meter tampering benefit.

A. Improved data and analytics enabled by AMI technology will reduce energy theft through better detection and prevention capability, which can provide an overall cost benefit for customers. Today, customers who have been disconnected and try to reconnect their service illegally typically do so by removing the meter, removing the "boots" placed on the meter contacts, and then replacing the meter.[8] This is an illegal and extremely unsafe

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[8] In accordance with the Commission's order in Case No. 20-00205-UT, SPS is not currently disconnecting residential customers in New Mexico.

practice. When AMI technology is in place, remotely disconnecting service will involve opening a disconnection switch on the meter to disconnect power to the customer. However, the meter still has power and can communicate over the network. If a customer removes the meter from the socket to bypass it, SPS would receive a notification flag over the network to indicate meter tampering. This will improve detection of instances where customers illegally bypass our meter to receive electricity without paying for it. These situations require time-intensive identification to detect today, but they can be detected automatically through AMI technology. For safety reasons, however, these situations will still require a physical visit to remedy.

Q. Will the benefits described above help maintain reasonable operations, maintenance, and customer costs?

A. Yes. In addition to improving system efficiency, reliability, and operations, the benefits described above will provide quantifiable benefits and are included in the cost benefit analysis as described in more detail by Mr. Rohlwing.

Q. Does AMI provide any other benefits?

A. Yes. AMI will provide several other benefits to the operation of the grid and to customers that include:

- providing customers the ability to better manager their energy costs;
- enabling or enhnacing new demand-side management programs; and
- enabling greater distributed generation integration.

Q. Please describe how AMI will allow customers to better manage their energy costs.

A. Customers are increasingly savvy when it comes to smartphone applications and sophisticated websites. They are accustomed to engaging electronically to manage their accounts, resources, and service needs across many industries. Without advanced meters that can provide regular usage data, it is not possible to bring the energy industry along that same curve by developing sophisticated energy management and conservation tools, such as TOU rates, nor the applications and web-based tools that allow the customer to observe and manage their consumption. The improved interactions and data that will be available with AMI will provide customers with more control over their energy usage and bills. This includes the ability to know how much energy they are using at a given period of time and alerts if their monthly usage or bill amount is higher than normal. These services require advanced metering and more timely usage data in order to provide these services and controls to our customers.

Q. Please provide more detail on the data and information that AMI will provide to customers.

A. AMI will provide customers access to timely, accurate, consistent, and granular energy usage data that is necessary to develop personalized insights and that supports informed decision making. This includes enhanced visualization of energy usage data, including views of daily, hourly, and 15-minute interval energy usage information, as well as enhanced insights surrounding the data, including personalized energy saving tips, high usage alerts, and a usage and spending breakdown associated with primary in-home and business appliances and devices. With these insights and other data, customers will have more information to make energy usage decisions based on their preferences that can help reduce their bills and enhance their lives and businesses. In addition, SPS will make interval usage data available to authorized third-party providers via GBC, which will allow those providers to provide additional services to customers.

Q. How will AMI enable or enhance new demand-side management programs?

A. The more detailed and timely data that SPS's grid modernization investments provide can help enable or enhance programs in a number of ways. First, as SPS acquires more information regarding customer usage, it can update program designs and marketing tactics. SPS will have better insight into how and when customers use their energy which will allow it to better market and segment customers. This means that communications will be more relevant and SPS will be able to develop new products and services that support demand-side management goals.

Q. How will AMI enable greater distributed generation integration?

A. AMI will provide more timely and more granular data on the flow of energy to and from customers. As I described earlier in my testimony, SPS relies on conservative estimates to quantify the amount of distributed generation entering and leaving the grid. Because SPS must ensure adequate voltage and protection at all times, such conservative estimates, coupled with the inability to modify voltages or system configuration, can limit the accommodation of DER. With this additional data and information, SPS will be able to facilitate the integration of greater amounts of distributed generation on to the system. In addition, in certain instances the bi-directional capabilities of the AMI meters will allow the ability to perform net metering for our DER customers without the need to change out the existing meter.

Additionally, the AMI system will capture voltage and usage data which can be compared with nameplate or operational limits of SPS's equipment. Using this data, SPS will be able to identify problems such as solar causing high secondary voltage, or transformer overload due to either a strong presence of electric vehicles (load) or high reverse flows (such as solar generation). It is SPS's intention to leverage AMI data for this purpose, which will allow SPS to enable DER while at the same time maintaining reliability and power quality for customers.

Q. Overall, will the implementation of AMI provide benefits to SPS's New Mexico retail customers?

A. Yes. For the reasons discussed above, the implementation of AMI will benefit SPS's New Mexico retail customers, and is in the public interest.

B. <u>The Benefits of FLISR</u>

Q. Please summarize how FLISR will improve electrical system efficiency, reliability, and operations.

A. As discussed previously in my testimony, SPS's field switches on the distribution grid are nearly all manually operated switches and when an issue occurs, field crews must patrol a distribution line to find the location of the fault. This process can be time consuming.

FLISR has the potential to benefit the operation of the distribution grid and customers by providing information about the location of faults and automatically restoring power for customers. This will help improve the system efficiency, reliability, and operations. More specifically I will describe the following benefits:

- customer benefits from improved reliability;
- outage patrol time savings; and
- enhanced visibility and control of the distribution grid.

Q. How will FLISR provide reliability benefits?

A. Overall, implementing FLISR will allow SPS to more efficiently restore power to customers with the use of fewer resources and will improve customer's outage experience. Specifically, if there is a fault on a feeder that is automated with FLISR, SPS will be able reduce the number of customers who experience a sustained outage and will shorten the duration of certain sustained outages that affect a substantial portion of our customers.

Q. How will FLISR reduce the number of customers who experience sustained outages?

A. FLISR will allow SPS to restore service to customers affected by an outage within minutes of a fault. In the event of a fault, the FLISR protective devices will reclose, or sectionalize the feeder, and send data to ADMS. ADMS will then step through the FLISR sequence. The first step is fault location, identifying the location of the fault to, at minimum, between two automated field devices. Next, FLISR will proceed to isolation, in which ADMS will send open commands to automated field devices necessary to isolate the faulted section of feeder. Last, FLISR will execute service restoration, which will restore power to all possible customers.

This process is expected to take from 15-45 seconds from start to finish and by design, restore power to a portion of the customers on that feeder. After the service restoration step, system operators will send a crew to the isolated section to investigate the fault event, make repairs, and restore service to the remaining customers. As I described earlier, a feeder level fault will impact on average 626 customers for 85 minutes. FLISR will reduce the number of customers who experience a sustained outage and reduce restoration times for the remaining customers that do experience a sustained outage.

Q. How will FLISR provide outage patrol savings?

A. A primary benefit of FLISR is fault location prediction capabilities that will allow SPS to dispatch field cerws directly to the location of the fault, as opposed to having field crews patrol a distribution line to find the location of the fault or issue which can be time consuming.

Q. How will FLISR enhance visibility and control of the distribution grid?

A. As I described earlier, SPS has very limited visibility of the distribution grid beyond the substation level. FLISR provides key data at critical points along the system, which when integrated with ADMS provides additional insights into the operation and planning of the distribution grid. The increased system visibility will also improve reliability management efforts by increasing the quality and amount of the information SPS is able to analyze. In addition, these FLISR devices can capture momentary or transient fault and disturbance information, providing the ability to proactively identify potential issues on the distribution system.

Q. Will FLISR enable greater distributed generation integration?

A. Yes. Similar to AMI, FLISR will provide more timely and granular data on the flow of energy at several points along the distribution grid. This data can be used to enhance the operation and planning for distributed generation resources.

Q. Will the implementation of AMI, FAN, and FLISR allow for capital investment and skilled jobs in related services?

A. Yes. As discussed below, SPS plans to implement over $30 million in capital investment to implement AMI, FAN, and FLISR between 2022 and 2025. Skilled labor will be necessary to implement and maintain this investment.

Q. How are changing customer needs and preferences driving the need for grid modernization?

A. The needs and preferences of customers continue to evolve in the digital age, with increasing dependence on information and the connectivity of digital devices. While incremental modernization efforts have taken place on the distribution system over many years, and we have used these investments to provide reliable power for decades, we (along with the broader industry) believe now is the right time to begin a more significant advancement of the grid. Technological advances now make it possible to meet growing customer expectations for a more robust, reliable, and resilient system, as well as customer desire for more insight and visibility into the energy choices they are making.

IX. DISTRIBUTION COSTS ASSOCIATED WITH AMI, FAN, AND FLISR

Q. What Distribution costs does SPS propose to recover through the GMR?

A. The Distribution costs that SPS proposes to recover through the GMR include material and equipment, labor, and vendor services associated with the implementation of AMI, FAN, and FLISR.

Q. What Distribution capital costs are you supporting for the grid modernization components?

A. Distribution's grid modernization capital additions that I am supporting for rider recovery are shown in Table CSN-5 below. These costs are forecasts intended to illustrate the scope of projected costs, subject to annual forecasts and true-ups through the GMR as described by SPS witness Stephanie N. Niemi.

Table CSN-5
Grid Modernization Distribution - Capital Additions
(New Mexico Retail)
(Dollars in Millions)

Component	2022	2023	2024	2025
AMI	$5.26	$16.17	$0.42	$0.00
FLISR	$0.00	$2.06	$2.42	$0.50
FAN	$0.47	$1.75	$0.94	$0.12
Total	**$5.73**	**$19.98**	**$3.78**	**$0.62**

*There may be differences between the sum of the individual project amounts and total amounts due to rounding.

Total Distribution capital additions for AMI, FAN, and FLISR are also set forth in Attachment CSN-1 to my direct testimony. I provide additional details and support for Distribution's capital costs below.

Q. What types of O&M costs is Distribution incurring to implement AMI, FAN, and FLISR?

A. Distribution's O&M costs include outside vendor contracts, employee expenses, and contract labor. All internal labor costs have been excluded as they are reflected in base rates.

Q. What are Distribution's forecasted O&M costs for the implementation of AMI, FAN, and FLISR?

A. The forecasted grid modernization O&M expenses for Distribution are shown in Table CSN-6. As with capital costs, these O&M costs are forecasts intended to illustrate the scope of projected costs, subject to annual forecasts and true-ups through the GMR as described by Ms. Niemi.

Table CSN-6
Grid Modernization Distribution - O&M Expenses
(New Mexico Retail)
(Dollars in Millions)

Component	2022	2023	2024	2025
AMI	$0.08	$0.51	$0.52	$0.14
FLISR	$0.00	$0.07	$0.14	$0.09
FAN	$0.12	$0.12	$0.25	$0.21
Total	**$0.20**	**$0.70**	**$0.91**	**$0.44**

Total Grid Modernization O&M costs are provided in Attachment CSN-2 to my direct testimony by cost element and in Attachment CSN-3 by FERC account. I provide additional details and support for the Distribution O&M costs below, organized by component.

A. Distribution Costs for AMI

1. Distribution Capital Costs of AMI

Q. Was Distribution primarily responsible for the forecasted capital costs for AMI?

A. Distribution is responsible for the costs associated with acquiring and installing the AMI meters. I describe how we developed our forecast for these costs in more detail below. Business Systems is responsible for developing the costs and forecasts for the head-end application, other software and hardware to support AMI data processing, and integrations required by those technologies, and Mr. Remington will address the development of those costs.

Q. What are the projected capital additions for AMI from 2022-2025?

A. Table CSN-7 provides a breakdown of Distribution's capital additions forecasts for AMI for 2022 through 2025.

Table CSN-7
AMI Distribution - Capital Additions
(New Mexico Retail)
(Dollars in Millions)

	2022	2023	2024	2025	Total
AMI	$5.26	$16.17	$0.42	$0.00	$21.85

Q. What are the primary components of Distribution's AMI capital forecast?

A. Distribution's AMI capital forecast has five key components: (1) AMI meter purchase; (2) AMI meter installation; (3) vendor project management; (4) AMI operations (external and internal); and (5) testing equipment.

Q. How did Distribution develop its capital forecast for the AMI meter and installation costs?

A. The costs for the AMI meters and installation are based on the meter contract with the AMI meter vendor, Itron. Additional overheads such as taxes are also included in these estimates.

Q. Describe the process used to select the AMI meter vendor.

A. Xcel Energy issued an RFP in March 2018 to select an electric AMI meter vendor that could provide an AMI meter, project management, and installation services. As part of the RFP process, potential vendors were asked to review Xcel Energy's priorities and vision for its AMI solution including the capabilities desired for this technology. The vendors were then asked to provide precise and detailed responses to numerous technical questions regarding their AMI meter offerings related to the following:

- technical standards of their meter;
- capabilities of their meter;
- compatibility of their AMI meter with other grid modernization components;
- data and cybersecurity safeguards;
- plan and schedule for technology development, integration, and AMI deployment; and
- itemized pricing information for their AMI meter and installation.

Q. How many companies responded to the RFP?

A. Four different companies responded to the RFP.

Q. How did Xcel Energy evaluate these RFP responses?

A. Xcel Energy evaluated these responses based on a number of factors including: (1) total cost; (2) schedule requirements; (3) core metrology; (4) customer benefits and capabilities; (5) integration with the selected Network Integration Card from Silver Springs (which was purchased by Itron); (6) future proofing/new technology; (7) commercial terms and conditions; and (8) security.

Q. Were there other capabilities that Xcel Energy desired for the new AMI meters?

A. Yes. Xcel Energy was also interested in making sure that the selected AMI meter could support distributed intelligence capabilities. These capabilities were an important consideration as Xcel Energy understood the customer-facing, operational, and future-proofing benefits that these capabilities could provide.

Q. Did Xcel Energy select an AMI meter and installation vendor from these RFP responses?

A. Yes. Based on an assessment and comparison of the capabilities, price, and schedule commitments provided in the RFP responses from these four different meter vendors, Xcel Energy selected a meter vendor and issued a Limited Notice to Proceed to that vendor in December 2018. However, in late March 2019, Xcel Energy learned that the meter vendor that was initially selected would not be able to integrate certain capabilities while also meeting the meter deployment schedule set forth in the Limited Notice to Proceed. As a result, in April 2019, Xcel Energy solicited and received a comprehensive proposal from another meter vendor that responded to the initial RFP. This meter vendor was able to meet the requested deployment schedule with the necessary integration, offered the necessary meter capabilities, and offered favorable price and contractual terms. As a result, in May 2019, Xcel Energy selected Itron as its meter vendor to serve all jurisdictions, including SPS, and a contract was executed on September 1, 2019 (the "Meter Contract").

Q. Why did Xcel Energy select Itron as its meter vendor?

A. The primary factors in the decision were:

- lowest cost/best overall value for an offering that included distributed intelligence and grid edge technology;

- lowest risk solution / least complexity;
- the vendor met Xcel Energy's deployment schedule;
- single vendor solution (Itron is already under contract for the mesh network and the head-end software);
- met or exceeded Xcel Energy's core metrology requirements, including distributed intelligence capabilities; and
- most favorable overall commercial terms and conditions, including for edge technology/distributed intelligence.

A summary of the analysis supporting the selection of Itron is provided as Attachment CSN-4.

Q. How did Distribution develop its capital foreast for the AMI vendor project management costs?

A. The forecast for AMI vendor project management is set forth in the Meter Contract. SPS's estimates also include internal overheads.

Q. How did Distribution develop its capital forecast for AMI operations related to internal and external personnel?

A. Cost estimates for internal and external personnel were developed based on the role and number of required personnel required to perform necessary tasks to enable installation and deployment of the AMI meters. The necessary positions include analysts, projects and project managers, engineers, and electricians. The cost estimates were determined using average pay scales for the needed positions combined with an estimate the amount of work required by each of these roles during the AMI installation and deployment. SPS then determined the appropriate allocation between capital and O&M for these costs based on the type of work being performed.

Q. How did Distribution develop its capital forecast for testing equipment

A. These cost estimates were based on quotes obtained and purchases that were made from vendors for this testing equipment. This testing equipment is standard off-the-shelf equipment and Xcel Energy leveraged relationships with existing vendors to obtain the best cost for this equipment.

2. Distribution's O&M Costs for AMI

Q. What are Distribution's O&M costs associated with AMI?

A. The primary components of Distribution's AMI O&M expense include outside vendor contracts, employee expenses, and contract labor. All internal labor costs have been excluded as they are reflected in base rates. These expenses relate to the following categories of work that I describe in more detail below: (1) support of the capital deployment, (2) business readiness, and (3) change management. Table CSN-8 below provides a summary of Distribution's O&M expense forecast for AMI for 2022 through 2025.

Table CSN-8
AMI Distribution – O&M Expenses
(New Mexico Retail)
(Dollars in Millions)

	2022	2023	2024	2025	Total
AMI	$0.08	$0.51	$0.52	$0.14	$1.30

Q. What O&M expenses are included in the Capital Deployment category?

A. This category includes expenses related to equipment installations that are appropriately deemed O&M. For instance, any repair activities that are necessary to perform the meter exchange would be deemed an O&M expense.

Q. What is included in the Business Readiness cost category?

A. This category includes the costs to support the business readiness activities that are necessary to ensure the business is prepared and processes are in place to support the AMI meter and applications.

Q. What is included in the Change Management cost category?

A. The change management costs consist of general change management activities such as training and communications, which I discuss in more detail below. This includes the O&M portion of costs for development and delivery of training needed to prepare SPS's employees and contractors for the AMI meters and data management systems being deployed to support AMI. It also includes costs in the development and delivery of internal communications in support of the change management plan necessary to engage and prepare the business for upcoming changes due to AMI.

3. Distribution Contingency for AMI

Q. Does Distribution's AMI capital forecast include contingency amounts?

A. Distribution's capital forecast in 2023 does include contingency amounts that may be necessary to address potential cost increases to support the AMI meter installations that currently are not known. This could include any upgrades necessary to complete the meter exchange, such as the upgrades to the wiring and meter socket that are not known until the meter exchange is done.

Q. In summary, why are the Distribution AMI costs reasonable and necessary?

A. AMI is a fundamental element of the grid modernization initiative because it provides a central source of information that interacts with many of the other components of the initiative. The system visibility and data delivered by AMI provides customer benefits in reliability and ability for remote connection, enables greater customer offerings for rates, projects, and services. AMI also enhances utility planning and operational capabilities. Access to timely, accurate and consistent data from the AMI system will provide insights for customers to make informed decisions about their energy sources and usage of reliable and sustainable energy. Distribution's capital investments described above that include the AMI meters are necessary to implement AMI and Distribution's capital and O&M forecast is reasonable.

B. Distribution's Costs for FLISR

1. Distribution's capital costs for FLISR

Q. Was Distribution primarily responsible for developing the forecast for FLISR?

A. Yes. Distribution developed its forecast for FLISR by using data from actual installations of comparable devices, as well as pricing details from vendors and projects that require the same field device equipment.

Q. What is the projected capital investment for FLISR and FLP for 2022 through 2025?

A. Table CSN-9 below provides a breakdown of Distribution's capital additions forecasts for FLISR and FLP for 2022 through 2025.

Table CSN-9
FLISR and FLP Distribution - Capital Additions
(New Mexico Retail)
(Dollars in Millions)

	2022	2023	2024	2025	**Total**
FLISR and FLP	$0.00	$2.06	$2.42	$0.50	$4.98

Q. What are the primary components of the FLISR and FLP capital forecast?

A. The primary components of the FLISR and FLP capital forecast, shown above, include: (1) device costs, which include device replacements, and (2) installation costs, which include project management, labor, and commissioning support.

Q. How did Distribution derive the FLISR and FLP device costs?

A. SPS was able to use actual costs to develop the capital forecast for the FLISR and FLP devices, such as the costs for previous, completed projects utilizing the same equipment that will be deployed for FLISR and FLP.

With respect to device replacement costs, Distribution experiences a roughly 0.6 percent equipment failure rate per year. This includes various factors such as product infancy failure rates and equipment failures due to public or environmental damage. This failure rate was applied to total equipment quantities to determine the number of devices that would need to be replaced and accurately reflect those costs in the FLISR and FLP deployments.

Q. How did SPS estimate the installation costs for FLISR and FLP?

A. The installation costs for FLISR include the capitalized costs for installing and commissioning FLISR devices (switches, reclosers, sensors, and relays). In addition, other Xcel Energy Operating Companies have installed FLISR devices, and Distribution was able to use historical installation and labor costs to develop the capital cost estimates.

2. Distribution's O&M Costs for FLISR and FLP

Q. What are Distribution's O&M costs associated with the implementation of FLISR?

A. The primary components of Distribution's AMI O&M expense include outside vendor contracts, employee expenses, and contract labor. All internal labor costs have been excluded as they are reflected in base rates. These Distribution's O&M costs for FLISR will include costs in the following categories: (1) capital support; (2) on-going asset/device support; (3) device replacement; (4) on-going communications network; and (5) training. Table CSN-10 provides a breakdown of Distribution's O&M expense forecast for FLISR and FLP for 2022 through 2025.

Table CSN-10
FLISR and FLP Distribution – O&M Expenses
(New Mexico Retail)
(Dollars in Millions)

	2022	2023	2024	2025	**Total**
FLISR and FLP	$0.00	$0.07	$0.14	$0.09	$0.30

Q. What is included in the Capital Support cost category and how were these costs estimated?

A. This category includes expenses related to equipment installations that are appropriately deemed O&M. One example is certain switching operations necessary to safely install new equipment. SPS used actual, average installation times to develop these cost estimates.

Q. What is included in the On-Going Asset/Device Support cost category and how were these costs estimated?

A. This category includes labor and repairs to maintain assets in good working order. SPS estimated the annual support costs by multiplying per-unit support cost estimates by the quantity of devices in service each year.

Q. What is included in the Component Replacement cost category and how were these costs estimated?

A. This category includes material and labor to replace batteries for certain devices on a five-year schedule. SPS estimated these costs by multiplying per-unit replacement cost by the quantity of devices expected to need battery replacement each year.

Q. What is included in the On-Going Communications Network Cost Category and how were these costs estimated?

A. This category includes costs to maintain communications to the field devices. SPS estimated these costs based on historical time to troubleshoot device communication issues and an estimate of the quantity of devices which typically have required such maintenance.

Q. What is included in the Training Cost category and how were these costs estimated?

A. This category includes training costs for the FLISR project. SPS estimated these costs based on the labor costs of the employees requiring FLISR training (control center, engineering, line crews, etc.) and the time required to train them.

3. Distribution's Contingency for FLISR

Q. Does Distribution's capital forecast for FLISR include contingency?

A. Distribution's FLISR capital forecast for the period 2022-2025 includes a contingency of five percent. This smaller contingency percentage is considered adequate because the cost projections for FLISR devices and installation were developed based on historical costs and should be a fairly accurate estimates of actual costs.

Q. In summary, why are the Distribution Business Area's FLISR costs just and reasonable?

A. Customers expect reliable power from their utility and the need for higher reliability has never been greater. The current pandemic has emphasized our increased dependency on high reliability throughout the service territory – even in remote areas as more people are working from home. Commercial and Industrial customers are more reliant on processes, equipment and cloud computing that require higher degree of electric reliability as well. The implementation of FLISR will enhance the reliability of SPS's system and target areas that historically have experienced a higher number of outages. Enhancing the reliability of SPS's system will not only improve reliability for existing customers but can be important for attracting industries that require higher reliability to New Mexico, which in turn can bring jobs and economic development.

C. Distribution's Costs for FAN

1. Distribution's Capital Costs for FAN

Q. Was the Distribution Business Area primarily responsible for developing the forecast for FAN?

A. As discussed above, the work that Distribution will be performing to support the implementation of FAN is limited to the procurement and installation of pole-mounted FAN devices.

Q. What is the projected capital investment for FAN?

A. Table CSN-11below provides a breakdown of Distribution's capital additions forecasts for FAN for 2022 through 2025.

Table CSN-11
FAN Distribution - Capital Additions
(New Mexico Retail)
(Dollars in Millions)

	2022	2023	2024	2025	**Total**
FAN	$0.47	$1.75	$0.94	$0.12	$3.28

Q. What are the primary components of Distribution's capital forecast for the FAN?

A. The primary components of the Distribution Business Area's capital forecast for the FAN are (1) make ready work (labor and hardware) and (2) FAN device hardware and installation (labor and hardware).

Q. How did Distribution develop these capital cost estimates for FAN?

A. To estimate the device costs and installation costs for FAN, engineering performed a preliminary Radio Frequency Network Study. The purpose of this study was to determine the location and number of access points and repeaters that would be required to facilitate a reliable FAN communication network for the AMI meter and the distribution automation devices.

Q. What was the next step in developing the capital cost estimates?

A. After determining the number of devices, the price for each device was derived from prices included in contracts that resulted from several RFP processes as described by Mr. Remington. The labor costs to install each device are based on a combination of materials, contractor, and internal labor.

Q. How did Distribution determine the labor costs for the installation of the FAN devices?

A. Distribution based the labor estimates on prior experience with installing FAN devices in other Xcel Energy jurisdictions.

2. Distribution's O&M Cost for FAN

Q. What are the projected O&M costs for FAN?

A. Table CSN-12 below provides a breakdown of Distribution's O&M expense forecast for FAN for 2022 through 2025.

Table CSN-12
FAN Distribution – O&M Expenses
(New Mexico Retail)
(Totals in Millions)

	2022	2023	2024	2025	**Total**
FAN	$0.12	$0.12	$0.25	$0.21	$0.70

Q. What are the primary components of Distribution's O&M costs for FAN?

A. The FAN's O&M costs will include outside vendor contracts, employee expenses, and contract labor. All internal labor costs have been excluded as they are reflected in base rates. These expenses relate to costs for infrastructure and hardware, operations (including equipment and personnel), and preparation costs. These costs include the field level support for fixing broken and damaged equipment, additional personnel to monitor and manage the FAN, other preparation work that is designated as O&M, hardware and software maintenance, and training. Personnel will include both SPS employees and contractors, which will be used based on workload, location, and timing. Most incremental work will be performed by contractors.

Q. How did Distribution determine the O&M costs for FAN?

A. The projected costs associated with project employees are based on typical SPS wages, and contractor costs are costs of contractors at estimated wage scales. The costs to fix and replace broken and damaged equipment are based on expected failure and damage rates for these devices.

3. Distribution Contingency for FAN

Q. Does Distribution's capital forecast for FAN include contingency?

A. Yes there is a contingency amount included in Distribution's FAN costs due to the steps that need to be taken to ensure a reliable communication network from the current state, which is expected to vary as SPS deploys FAN across the New Mexico geographic terrain.

Q. In summary, why are the Distribution FAN costs just and reasonable?

A. The FAN enables the grid modernization devices and components to communicate with each other in a safe, secure, and reliable way. This communication is essential to harnessing the benefits of the grid modernization initiative in that it allows greater visibility into the customer experience at the edge of the grid. The Distribution components and their installation, as described above, are necessary to implement FAN and the Distribution forecast is reasonable.

X. CUSTOMER EDUCATION AND OUTREACH

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I will discuss SPS's plan to communicate with customers regarding the implementation and benefits of the Grid Modernization components.

Q. Is SPS planning to educate customers regarding the ability to opt out of an advanced meter?

A. Yes. SPS proposes to align its customer education regarding AMI opt-out with its overall Plan to educate customers regarding AMI.

Q. Has SPS developed a Customer Education Plan?

A. Yes. SPS has created a Customer Education Plan ("Plan") to educate customers on grid modernization and the associated products and services. A copy of the Plan is provided as Attachment CSN-5 to my direct testimony.

Q. How does SPS plan to reach customers regarding the Plan?

A. There are three phases to the Plan strategy included in Attachment CSN-5. The first phase includes raising awareness through an introductory and wide-reaching effort to inform customers about AMI meter installations and educate them on the overall benefits of grid modernization. The second phase will support successful AMI meter installations by sending notification materials to customers prior to the installation of their AMI meter. The third phase involves customer engagement, which will continue post-AMI meter installation so that customers can take full advantage of the AMI features and opportunities to save money. The strategies will be executed across multiple communications channels including, but not limited to, website updates, stakeholder outreach meetings, media outreach, social media, blogs, direct mail, e-mail, outbound calls, door hangers, community events, bill onserts, targeted advertising, fact sheets, video, and customer testimonials.

It is important to use a diverse set of communications channels to reach customers in their preferred manner. As of May 2021, approximately 53,695 residential and 9,950 business customers (total 64,645 SPS customers) have chosen email as their preferred method of communications. This represents approximately 63 percent of all electric customers in New Mexico. This is another reason to use diversified communications channels to help ensure that all customers receive adequate information and education.

Q. Has SPS previously utilized these strategies?

A. Yes, these strategies have been used in a variety of communications plans for introducing new programs or initiatives, including Energy Efficiency programs. Each communications strategy is different and based on the unique challenges and specifics of each plan's objectives.

Q. Why are the strategies SPS is proposing effective for educating customers?

A. These strategies are effective for educating customers because they provide information over a period of time, and each phase builds upon the previous one. Phases I through III gradually increase the complexity of information being provided to customers, and each will be adjusted based on customer feedback as time progresses. These strategies use almost every possible communications channel so that each customer can be reached through the channel that they prefer (e.g., email, direct mail, bill onserts, etc.).

Q. What are the relative timelines for launching each customer education phase?

A. The timelines for each phase are included in Table CSN-13 as follows: Phase I – Raising Awareness would take place from Q2 2022 to Q3 2023; Phase II – Supporting Meter

Installation would happen from Q3 2022 to Q4 2023; Phase III – Customer Engagement would take place from Q1 2023 to Q4 2023. For example, customers receiving their meter in the fourth quarter of 2022 would see a bill onsert 90 days prior (July of 2022) to meter install, a postcard 60 days prior (August of 2022) to meter install, and a letter or e-mail 30 days (September of 2022) prior to meter install. There will also be mass communications supporting advanced meter installation. These communications will commence at the beginning of 2021.

Table CSN-13: Customer Education Timeline

Phase	Event	Timing
I	Raise awareness	Q2 2022 – Q3 2023
II	Informing meter installation	Q3 2022 – Q4 2023
III	Customer engagement	Q1 2023 – Q4 2023

This is in conjunction with the planned timing for AMI meter installations commencing in the fourth quarter of 2022.

Q. Can you describe in more detail the communication plan to customers prior to the installation of an AMI meter?

A. Yes. The Plan includes a high-level 90-day communication with a bill onsert, a follow up with the 60-day postcard via mail, followed by a 30-day letter. The 30-day communication may be delivered as an email or a mailed letter, depending on the customer's communication preferences. Each customer will receive a pre-installation outbound call alerting them of a timeframe window when the installation of their AMI meter will take place. Two types of door hangers will be left upon meter installation : "Meter Installed" door hanger or "Sorry We Missed You" door hanger. If we were unable to install a meter, the door hanger will provide a reason and, information to re-schedule the installation. This approach, including the other tactics proposed as part of the Plan, is based on best practices from other utilities, such as Commonwealth Edison ("ComEd") in Chicago and Entergy located in multiple states. ComEd has successfully installed over four million advanced meters in the Chicago metro area, and Entergy is in the process of its advanced meter deployment in Arkansas. There are also several other communications tactics that will be used, which can be found in Attachment CSN-5.

Q. Will SPS's communications plan aim to fully educate customers regarding AMI technology?

A. Yes. When customers are about to receive an advanced meter, they will receive several types of communications over time leading up to the meter installation. They will also be informed as to the terms of advanced meter opt-out, described further in the next section of my testimony. There is a great deal of information for customers to process in the same time period, making clarity and simplicity critical.

XI. <u>OPT-OUT LOGISTICS AND COMMUNICATIONS</u>

Q. Please describe the extent to which customers will be able to opt-out of receiving an AMI meter.

A. SPS will provide Residential and Small Commercial customers the opportunity to opt-out of receiving an AMI meter. These customers can also request to have their AMI meter removed after installation. I will describe the costs of customers opting out in more detail below.

Q. Will customers who opt-out receive a new meter?

A. Yes. The customers who opt-out will receive a non-communicating interval data meter, also referred to as an opt-out meter, instead of receiving an AMI meter. The non-communicating meter will have more limited capabilities in part since it will not be able to communicate; however, it will still provide interval data that supports billing functions, customer access to interval data through the customer portal, and will support more advanced rates such as time of use rates.

Q. How will customers opt-out of an AMI Meter?

A. Customers will have the opportunity to opt-out of an AMI meter by calling or emailing SPS's Customer Service department, in a similar process as shown at the bottom of Attachment CSN-5.

Q. When can customers opt-out of an AMI Meter?

A. Customers can opt-out of their AMI meter as soon as the opt-out policy is approved by the Commission and even after the AMI meter has been installed. If the opt-out is requested after the AMI meter has been installed, in addition to the one-time fee, a meter exchange cost will be charged to the customer.

Q. Can customers opt-out of an AMI Meter when an installer is there to install the meter?

A. No. Customers need to verify their opt-out choice in writing via email or on a recorded call with SPS's Customer Service department to accept the charges associated with opt out. If a customer asks a meter installer to opt-out when the meter installer is on-site to install the AMI meter, the meter installer will provide information to the customer on how to opt-out and the customer will have to directly contact SPS's Customer Service department by telephone or email. A meter installer does not have the ability to opt-out a customer on-site.

Q. Please describe the frequency of communications informing customers directly of the option to opt-out?

A. Customers will be directly informed of the option to opt-out on three separate occasions to meter installation: at 90-, 60-, and 30-day intervals prior to installation as described in the Plan.

Q. How will customers be educated on AMI meter opt-out?

A. Starting with the 90-day bill onsert, customers will have access to online information regarding opt-out costs and instructions on SPS's website. Both the 60-day and 30-day communications will direct customers to information sources, as well as provide the telephone number and email address to request an opt-out with SPS's Customer Service department. Attachment CSN-5 outlines this information in greater detail. FAQ's will be updated with opt-out costs and instructions, including examples for different scenarios for customer convenience (i.e. opting out before installation, opting out after installation, opting out and then moving, etc.).

Q. What other communications channels will provide customer education concerning Advanced Meter opt-out?

A. In addition to direct customer communications, opt-out information will be available primarily on SPS's website and in FAQ's. Overall information on opting out will also be included in information provided at stakeholder outreach and community meetings which are outlined in greater detail in Attachment CSN-5. Customer service agents will receive the requisite training to handle customer opt-outs.

Q. Will SPS conduct any communications to mitigate the number of customers who opt-out?

A. Yes. SPS has already developed preliminary materials to address these primary concerns including radio frequency (RF) and privacy concerns, including FAQ's[9]. These materials will continue to be built upon in 2021 leading up to direct communications in 2022 to include additional web and video content. Media briefings will also be created to keep the media informed of the facts concerning RF.

In addition, messaging concerning the overall customer benefits of the AMI technology will be promoted to customers directly as well as through mass market communications channels as detailed in Attachment CSN-5. Call center agents will also be equipped with messaging to help customers understand the facts of RF if this is the reason the customer is opting out. This messaging will be shared when the customer calls to request an opt-out.

Q. How many customers are expected to opt-out?

A. Based on the experience of Xcel Energy and the experience of other utilities who have deployed AMI meters, the opt-out rate is expeted to be a very small number of customers. The opt-out rate costs are based on an estimated opt-out rate of 0.5 percent.

Q. Can you describe the costs to customers who opt-out?

[9] www.xcelenergy.com/NewMeter

A. Yes. The opt-out costs include a one-time fee and a recurring monthly fee. The one-time fee will recover the incremental costs for an opt-out program that include the IT costs to setup the opt-process and billing and the administrative costs to support the opt-out process. In addition, the one-time fee includes the costs for replacing the opt-out meter with an AMI meter once the customer vacates the premise in the future, which includes the cost for a trip charge for the meter exchange and the cost of the opt-out meter that was part of the initial installation.

For customers who opt-out prior to receving an AMI meter, the proposed one-time fee is approximately \$200. For customers who opt-out after receiving an AMI meter, an additional trip charge will be included and the total one-time fee will be approximately \$250.

In addition, the opt-out costs include a recurring monthly fee for manual reading services that will be needed to support billing for opt-out meters. The proposed recurring monthly fee for customers that opt-out is \$12.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

VERIFICATION

On this day, June 4, 2021, I, Chad S. Nickell, swear and affirm under penalty of perjury under the law of the State of New Mexico, that my testimony contained in Direct Testimony of Chad S. Nickell is true and correct.

/s/ Chad S. Nickell
CHAD S. NICKELL

Southwestern Public Service Company

Distribution Grid Modernization
Capital Additions for 2022 - 2025

				Addition Amount			
Program	**Project name**	**WBS Level 2#**	**Classification**	**2022**	**2023**	**2024**	**2025**
AMI	AMI-DIST-SPS-NM Full AMI	D.0001901.078	Electric Distribution	$ 5,259,703.95	$ 13,264,737.11	$ 419,043.35	$ -
AMI	AGIS-Dist-Capital-Line-AMI-Contin-NM	D.0001908.071	Electric Distribution	-	2,902,932	-	-
FLISR	AGIS SPS FLISR - Install Distributi	D.0001902.034	Electric Distribution	-	2,057,918	2,421,497	-
FLISR	AGIS-Dist-Capital-Line-FLISR-Contin-SPS	D.0001908.048	Electric Distribution	-	-	-	500,000
FAN	AGIS - FAN - SPS	D.0001900.300	Electric General	468,401	1,527,906	438,931	117,368
FAN	AGIS-Dist-Cap-Com-FAN-Cont-SPS	D.0001908.075	Electric General	-	226,843	500,705	-
	Total Distribution Capital Additions			**$ 5,728,105.25**	**$ 19,980,335.61**	**$ 3,780,175.08**	**$ 617,367.71**

Southwestern Public Service Company

Distribution Grid Modernization
O&M Expenses for 2023 - 2025

			Forecast Amount			
Program	**Posting Account**	**Description**	**2022**	**2023**	**2024**	**2025**
AMI	5600041	Outside Vendor Contract	$ 32,054.14	$ 109,575.46	$ 143,274.45	$ 622.43
AMI	5600246	Employee Expenses Other	5,255.85	5,132.17	13,654.24	13,907.94
AMI	5600001	Contract Labor	44,078.01	396,231.75	362,882.52	122,456.55
FAN	5600041	Outside Vendor Contract	102,252.74	94,592.82	190,631.36	187,122.27
FAN	5600246	Employee Expenses Other	2,100.19	1,438.17	2,666.10	5,829.70
FAN	5600001	Contract Labor	17,748.52	22,291.83	59,445.80	20,866.12
FLISR	5600041	Outside Vendor Contract	-	48,919.16	68,069.26	49,526.86
FLISR	5600246	Employee Expenses Other	-	570.27	2,592.59	7,762.75
FLISR	5600001	Contract Labor	-	17,358.74	71,322.98	27,785.04
		Total Distribution O&M	**$ 203,489.46**	**$ 696,110.37**	**$ 914,539.31**	**$ 435,879.67**

Southwestern Public Service Company

Distribution Grid Modernization
O&M Expenses by FERC Account for 2022 - 2025

			Forecast Amount			
Program	**FERC**	**Description**	**2022**	**2023**	**2024**	**2025**
AMI	9588000	Miscellaneous Distribution Expenses	$ 72,819.47	$ 461,786.05	$ 412,898.17	$ 22,865.88
AMI	9597000	Maintenance of Meters	8,568.54	49,153.32	106,913.04	114,121.04
FAN	9588000	Miscellaneous Distribution Expenses	122,101.45	118,322.82	252,743.27	213,818.10
FLISR	9588000	Miscellaneous Distribution Expenses	-	10,128.34	65,326.66	37,622.57
FLISR	9593000	Maintenance of Overhead Lines	-	56,719.83	76,658.16	47,452.09
		Total Distribution O&M	**$ 203,489.46**	**$ 696,110.37**	**$ 914,539.31**	**$ 435,879.67**

Summary of the Sourcing Process for the AMI meters of the Grid Modernization Project

In 2018 Xcel Energy issued a request for proposal ("RFP") to select an electric AMI meter vendor that could provide an AMI meter, project management, and installation services. As part of the RFP process, potential vendors were asked to review Xcel Energy's priorities and vision for its AMI solution including the capabilities desired for this technology. The vendors were then asked to provide precise and detailed responses to numerous technical questions regarding their AMI meter offerings related to the technical standards of their meters, capabilities of their meter, compatibility of their AMI meter with other components of the AGIS initiative, data and cybersecurity safeguards, plan and schedule for technology development, integration, and AMI deployment; and itemized pricing information for their AMI meter and installation.

Four companies responded to the RFP. Xcel Energy evaluated each vendor based on a number of factors that included:

- Total Cost
- Schedule Requirements
- Core metrology
- Customer benefits and capabilities
- Integration with the selected WiSUN network interface card (NIC) from Silver Springs (which was purchased by Itron)
- Future proofing and technology
- Commercial terms and conditions
- Security

Based on an assessment and comparison of the four different meter vendors, Xcel Energy selected Itron as its meter vendor for all jurisdictions and a contract was executed on September 1, 2019. The selection of Itron as Xcel Energy's meter vendor was based on the primary factors below:

- lowest cost/best overall value for an offering that included distributed intelligence and grid edge technology;
- lowest risk solution / least complexity;
- the vendor met Xcel Energy's deployment schedule;
- single vendor solution (Itron is already under contract for the mesh network and the head-end software);
- met or exceeded Xcel Energy's core metrology requirements, including distributed intelligence capabilities; and
- most favorable overall commercial terms and conditions, including for edge technology/distributed intelligence.

Advanced Grid Customer Education & Communication Plan

UPDATED: May 13, 2021

EXECUTIVE SUMMARY

A phased customer outreach effort is required to ensure effective change management, customer satisfaction and engagement to maximize benefits of the Advanced Grid Intelligence & Security ("AGIS" or "Advanced Grid") investments. SPS's Advanced Grid Customer Education & Communication Plan describes how the company recommends using a customer-focused strategy and sequential approach, as well as a variety of channels, tactics and messages to raise awareness and support meter installation, and customer engagement to help customers get the most out of this new technology.

This working plan presents a cost-effective, yet wide-reaching, customer education and communication plan for the smart meter installation customer experience, including technology that will provide energy tools and information. It is a living document and subject to change dependent upon New Mexico Public Regulation Commission (NMPRC) approvals that will provide final decisions and clarity regarding specific details of smart meter and smart grid programs and initiatives for our New Mexico customers. This plan is also subject to change based on any changes to meter installation schedules or timelines.

SPS plans to install roughly 120,000 smart meters to its New Mexico electric customers over a timeframe of approximately two years.

STRATEGY & COMMUNICATION OBJECTIVES

Our recommended education and communication campaign includes three phases, outlined below. This phased approach helps with the overall change management effort and is designed to ease customers through each stage of the smart meter deployment process.

Phase I - Raising Awareness: An introductory, wide-reaching effort to inform customers, employees, and community members about smart meter rollouts and the overall benefits of advanced grid intelligence.

Objectives during this phase include:

- Creating customer and stakeholder awareness about the overall benefits of the advanced grid.
- Explaining why the utility is making this investment, with a focus on customer benefits.
- Engaging public officials, reporters and others who can support the implementation process.
- Engaging opinion leaders and authoritative advocates.
- Measuring consumer awareness, understanding, and interest in having a smart meter and access to associated benefits.
- Educating New Mexico employees with customer or stakeholder relationships, so they can fully and effectively discuss the benefits and specifics of the advanced grid initiative.

Phase II - Informing Meter Installation: Targeted customer outreach by installation community and/or geographic areas. Communications in this phase focus on the actual meter installation.

Objectives during this phase include:

- Educating New Mexico customers about new meter deployment, ensuring that customers understand the installation process.
- Conducting outreach and notifications about installation to affected customers on a rolling basis.
- Providing communications that minimize confusion by anticipating and answering questions before customers ask them.
- Educating customers on the opt-out process and clearly outlining instructions and any associated costs.
- Measuring consumer awareness, understanding, interest, and participation in smart meter functionalities.

Phase III - Customer Engagement: Targeted follow-up communication to customers who have had a smart meter installed to ensure satisfaction with the process and informing them about how to take advantage of smart meter features.

Objectives during this phase include:

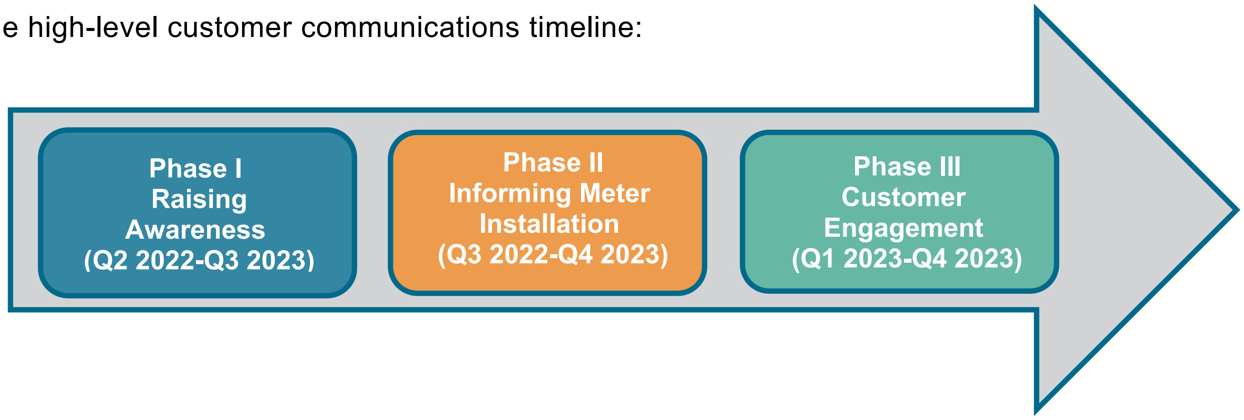
- Educating customers about the Home Area Network (HAN) which is part of their smart meter allows customers to receive their real-time about their energy demand consumption from the smart meter once activated on a mobile device.
- Educating and engaging customers who have had smart meters installed about online tools and resources.
- Encouraging customers to view their energy use information online.
- Providing follow-up communications to customers about specific ways to use this information to manage their energy use.
- Continuing education to those who have not activated the Home Area Network (HAN) about its benefits, which allows customers to receive their real-time, energy demand consumption from their smart meter.
- Making it easy for customers to select energy management tools and energy efficiency and conservation offerings available to them, based on their personal preferences.
- Measuring consumer awareness, understanding, interest, participation and satisfaction with smart meters and associated features.

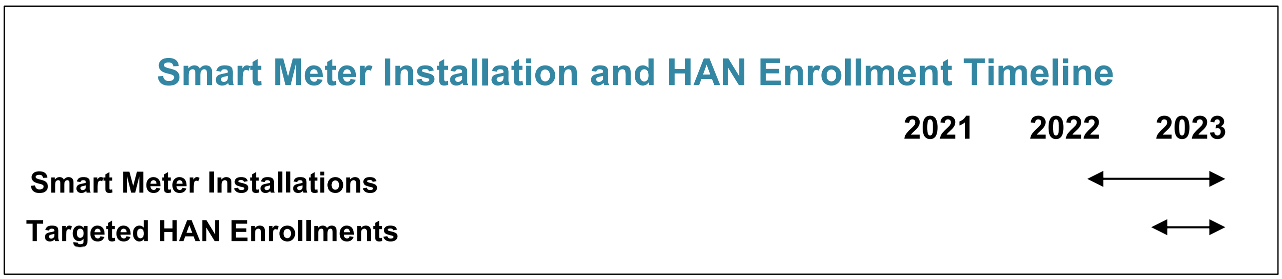
METER INSTALLATION & COMMUNICATIONS TIMELINE

The Advanced Grid Customer Education & Communication Plan's first awareness campaigns are expected to launch the second quarter of 2022, followed later in the year by communications to prepare customers for meter installations that will run throughout 2023. The technology is expected to be ready in the fourth quarter of 2021, and tested by the time it launches in New

Mexico in 2023.

The high-level customer communications timeline:





BEST PRACTICES & LESSONS LEARNED

To further build upon the company's experience with smart meter pilots and advanced grid technology initiativesSPS also has examined communication and outreach best practices among other utilities with advanced grid and smart meter deployment experience.

Many of these best practices and lessons learned are outlined below and have been taken into consideration in the development of this communication plan.

- Advanced grid/smart meter implementation should be treated as a change management program for employees. Consider a full process of engagement with employees throughout the life of advanced grid activities and initiatives.
- Training employees to be ambassadors in the community and leveraging employees' existing relationships and involvement in their communities to help disseminate important information. Aiming for transparency and a high level of engagement between the customer and customer-facing employees.
- Getting ahead of the process is important. Pre-deployment engagement makes all the difference: by talking to stakeholders first, the approach can be customized, and messaging can be localized by each community to effectively focus on issues and interests they care about the most.
- Educating customers before their smart meter deployment by staging communications ahead of key customer contact leading up to the actual installation.
- Using social media to approach smart meter installation as a new technology rollout across specific geographic locations and targeting customer segments.
- Focusing communication directly on customers. Do not assume they understand the concept of kilowatt hours, how the utility measures electricity, on- versus off-peak usage,

etc. Avoiding industry terms and jargon and instead using simple language and a call to action that customers can easily understand.

- Setting realistic expectations on smart meter functionality.
- Building an extensive set of FAQs to address issues and concerns. Through active employee change management and education, ensuring front-line employees who work directly with customers using these messages and anticipating questions, clearing up concerns, and addressing issues in an accurate and timely manner.
- Collecting customer success stories to make smart meter/advanced grid benefits tangible and understandable.
- Ensuring full integration and coordination of field operations, communication/marketing, customer care, and billing.
- Customer concerns must be identified quickly, elevated to the appropriate level, and resolved swiftly.

MESSAGE DEVELOPMENT, MARKET RESEARCH

SPS will develop a message framework using best practices and its own market research studies. The message framework will be essential for successful completion of this plan and the overall transition to smart meters. Market research lays the groundwork for message development, incorporating customer message testing, customer panels, focus groups, and utility peer research.

The objective of research will be to:

- Explore customers' current understanding of smart meters
- Understand the perceived benefits and drawbacks of smart meters
- Explore both positive and negative expectations consumers have about SPS moving customers to smart meters
- Explore reactions to different ways of describing smart meters
- Understand what barriers may arise and how to address them (pre or post smart meter installation)
- Understand how customers want to be communicated with about smart meters (what they want to know, and how they want to receive the information)
- Identify any differences between younger (under age 45) and older customers (45+) on these topics

Understanding the Audience: While we will be raising awareness among all our New Mexico customers, smart meter messages will ensure maximum effectiveness and tap into the benefits that customers care about the most.

Language and Tone: Messages will be developed using simple, straight-forward language and practical information that customers can easily understand and act upon. Xcel Energy will be working with its advertising agency of record – Carmichael Lynch – to explore the lexicons and language that resonate most with customers.

Overarching Messaging Themes: ***Customer Benefits & Value Propositions***

Because of the significant investment other utilities have made in the advanced grid, consumers today are seeing the benefits. The Smart Grid Consumer Collaborative ("SGCC") is an independent nonprofit organization consisting of commercial, utility, and advocacy organizations that collects information about customers' views and understanding of smart meters and grids. SGCC recently updated its advanced grid consumer segmentation framework, which highlights consumer attitudes. According to SGCC, three distinct value propositions of advanced grids have emerged:

Economic: With more information on energy consumption and more choices about how and when they use energy via possible future rate options, consumers may be able to save money as a result of advanced-grid enabled programs and technologies.

> Example messaging theme: *Smart meters and the smart grid provide superior energy usage information which can help consumers save money by enabling them to better manage their electricity use.*

Environmental: The advanced grid enables the incorporation of greater amounts of renewable generation, gives customers more opportunities to make more environmentally conscious choices, and can also reduce the need to rely on fossil fuel generation.

> Example messaging theme: *The smart grid helps reduce greenhouse gas emissions by making it easier to connect renewable energy sources to the electricity grid*.

Reliability: Grid-side intelligence offered by advanced grid technology can reduce the frequency and duration of outages while providing better information when outages do occur.

> Example messaging theme: *A smart grid senses problems and reroutes power automatically. This prevents some outages and reduces the length of those that do occur. It strengthens the resiliency of the power network that serves you.*

According to SGCC, the importance consumers place on these benefits has been remarkably consistent and strong, with nearly 90 percent of consumers rating each of these benefits as important, regardless of their awareness of advanced grid technology.

DEFERRAL AND OPT-OUT INSTRUCTIONS

Instructions for deferral and opt-out will be included in a personalized communications to customers during Phase II (smart meter installation) communications. Opt-out information will also be available our customer-facing website.

Note: Customers would still receive an interval data meter, even if they opt out of a smart meter. An interval data meter is essentially a smart meter without wireless network connectivity. It will measure electric use at set intervals, in order to measure both how much electricity is used and when it is used. This change also supports Time of Use Rates, which offer discounts for off-peak electricity use to motivate customers to conserve energy and shift their use to times of day when both costs and carbon emissions are lower.

COMMUNICATION CHANNELS AND TACTICS

Consistent with the lessons learned from numerous utilities that have managed smart meter deployments and advanced grid investments, the following are proposed communication channels and tactics focused on effectively reaching our target audiences.

Internal Channels and Tactics

Phase I: Raising Awareness

Internal Channel	Description
Talking Points and FAQs	Talking Points will provide employees with an overview of the advanced grid activities and smart meter/advanced grid benefits, including expected features and functionality. These messages can be used to guide discussions when engaging with or responding to customers. FAQs will provide answers to commonly asked questions, ensure accuracy of information shared with customers, and allow for timely replies to inquiries. A well-informed workforce helps carry the corporate message.
Employee Training & Speaker Resource Kit	Create materials and offer training opportunities for employees who will be working directly with affected customers. Target audiences will include, but not be limited to: Customer Care Agents, Field Crews (meter installers/meter readers), Billing Staff, Community Affairs Managers, Key Account Managers, State Government Affairs, and Regulatory Affairs.

Phase II: Informing Meter Installation

Internal Channel	Description
Talking Points and FAQs	Talking Points and FAQs will build upon existing messages but be further refined to include an added focus on specific smart meter installation details. This will include benefits to the customer and why and how the Home Area Network (HAN) needs to be activated after the smart meter is installed.
Employee Training	Efforts will build upon previous material but be further refined to help customers understand the smart meter installation process and what to expect before, during and after installation. The focus can be on assisting affected customers, gathering customers' feedback on the installation process, and helping customers through a smooth transition to the new technology.
Speaker Resource Kit	The existing Speaker Resource Kit will be expanded to include new information about how to aid customers pre- and post-installation of their smart meters.

Phase III: Customer Engagement

Internal Channel	Description
Talking Points and FAQs	Talking Points and FAQs will build upon existing messages but be further refined to include an emphasis on how customers can get the most out of their smart meter.
Employee Training	Create employee training guides that reflect the type of inquiries we are receiving from customers. Xcel Energy's Customer Care Quick Reference will be a dynamic tool to capture learnings on an ongoing basis. Provide specific employee training and walking customers through the activation process. This will include providing activation for tech-savvy customers and those non-tech savvy customers.

External Channels and Tactics

Phase I: Raising Awareness

External Channel	Description
Xcelenergy.com	Building on existing website resources, launch a dedicated smart meter/grid section on our customer-facing website. Content will include fact sheets, news releases, and other downloadable resources.
Bill Onsert	A bill onsert is an article or advertisement printed on an additional page of the bill. An initial bill onsert can feature an article about SPS's smart meter/grid modernization plans to raise initial awareness and interest in these upgrades.
Talking Points and FAQs	Fact sheets can focus on smart meter benefits and overall awareness of advanced grid benefits intended to inform customers of upcoming deployment plans.
Stakeholder Outreach & Community Meetings	We will reach out to community leaders, public officials and influential audiences to provide an initial briefing and enlist their help in sharing information. Conversations allow for dialogue and create opportunities for direct customer feedback into ongoing communications. These meetings also allow employees to reach out to populations that may otherwise be difficult to reach (such as vulnerable or low-income customers).
E-mail	E-mail can be used to promote awareness of the smart meter benefits to those who have indicated e-mail as a preferred channel. A new customer preference will be developed to automate delivery of emails in Phases II and III.
Social Media	Monitor social media for discussions regarding smart meters in communities where technology will be installed. Leverage social media as appropriate to disseminate messages to customers (via Twitter, Facebook, Instagram, etc.) using compelling video content.
Media Outreach	News releases and editorial boards provide reporters with information about the SPS's overall plan and vision for smart meter/advanced technology investments. Media Relations can provide fact sheets and other informational resources to reporters likely to cover smart meter activities and utility/energy news outlets.

Market Research	Measure consumer understanding and interest in having a smart meter and access to associated benefits as a result of Phase I activities.
Targeted Advertising: TV, print, radio, digital	Use advertising to raise awareness about smart meters and the installation process.

Phase II: Informing Meter Installation

External Channel	Description
Direct Mail	Customers will receive communications at 90, 60, and 30-day intervals prior to meter installation. Please see “Bill Onsert” section below for the 90-day customer communication. The 60-day communication will be a 6x9 mailed card alerting customers that smart meters will be coming to their neighborhood. It will also provide information about smart meters and their benefits. The 30-day communication will be an operational letter sent to the customer with FAQs. It will inform customers that their meter will be installed within the next 30 days and will set expectations for what will happen on the day of installation. All direct mail communications will provide contact information (via 1-800 number and email) if they have questions. The communications will engage customers to share their preferences and sign up for MyAccount. Customers will also be directed to the website for more details.
Outbound Calls	Each customer will receive a pre-installation outbound call alerting them of a timeframe window when the installation of their smart meter installation will take place.
Door Hangers	Two types of door hangers will be left upon meter installation: <u>“Meter installed” door hanger</u>: When installation is complete, a door hanger can inform customers about new meter, solicit customer experience feedback, and let them know where to find more information. A magnet affixed to door hanger can provide customer help line numbers and website reminders for future reference. <u>“Sorry We Missed You” door hanger</u>: If installation is unsuccessful, this door hanger will indicate the reason why and provide information to reschedule installation. Any needed corrections will also be listed on the door hanger with check boxes for the installer to note for the customer.
Xcelenergy.com	Additional content can be added to offer more online and downloadable resources for customers who are receiving smart meters.
Social Media	Monitor social media for discussions regarding smart meters in communities where technology will be installed. Leverage social media as appropriate to disseminate messages to customers (via Twitter, Facebook, Instagram, etc.) using compelling video content.
E-mail	Use e-mail to reduce direct mail costs if customers indicate it as a preferred communications channel.

Bill Onsert	The 90-day communication will be a bill onsert to create awareness about smart meters and their benefits.
Talking Points and FAQs	Talking points and FAQs will build upon existing messages but will be further refined to include an added focus on specific smart meter installation details and an overview of smart meter features – including specific information detailing customer benefits and why and how HAN needs to be activated after the meter is installed. FAQs will be included in the 30-day customer communication.
Stakeholder Outreach & Community Meetings	Community Affairs managers and State Government Affairs personnel will meet with public officials and community organizations in areas where smart meters are due to be installed. Examples of materials they can provide include specific information about the smart meter roll out in their area, FAQs to address specific constituent concerns, advance copies of materials affected customers will be receiving, and key Company contacts for questions. Face-to-face meetings with community groups, neighborhood associations, public officials, environmental organizations, business, nonprofits, clubs, and individuals to encourage them to share information and answer questions that may arise.
Community Event Sponsorships	Speaking opportunities in the communities where installations are taking place. Ensure community opinion leaders are informed about smart meters, help answer questions.
Media Outreach	As important milestones are reached, consider news releases and outreach to reporters to communicate those achievements.
Market Research	Measure consumer understanding, interest, and participation in having a smart meter as a result of Phase II activities.
My Account	Include additional content to the customer account web portal to provide energy usage information and energy management tips for customers with smart meters.
Connect Blog	Articles during Phase II can provide practical information, advice, and testimonials from customers who have had smart meters installed. Disseminate smart meter facts and dispel myths.

Phase III: Customer Engagement

External Channel	Description
Xcelenergy.com	Include newer fact sheets, FAQs, and video vignettes to existing web content. Create specific web page dedicate to HAN, which includes activation information and activation help information.
Bill Onsert	Provide basic information and reminders about smart meters, featured articles addressing smart meter/advanced grid topics, and engaging customers around the features of their smart meters.

Talking Points and FAQs	Additional fact sheets can focus “how-to” information for customers using MyAccount, understanding their bill and their personalized energy usage information and HAN – benefits, need to activate, activation support information.
Market Research	Measure consumer understanding, and interest participation and satisfaction as a result of Phase III activities.
Connect Blog	Blog articles to continue to educate, update, and enhance understanding of smart meters and energy management technologies as they are introduced.
Outbound Calls	Follow-up smart meter installation with an outbound call to provide activation help and resources.
E-mail	A follow-up email to smart metered customers can provide a check-in and drive them to available online resources for increased engagement – plus . measure customer satisfaction and address any activation issues.
Web-based instructional videos	Post on xcelenergy.com’s HAN page a “How-to” activate HAN for customers to help them through the activation process.
Quick version video content (social media)	Content to be pushed out through YouTube, Facebook, Twitter, etc. Highlight smart meter features in short 15-30 second pieces. Vignettes can build attention and provide educational moments for customers in a variety of channels, including public meetings.
Customer Testimonials	Customers can provide first-hand accounts of ways they have used their smart meter information for managing energy usage and costs. This will be dependent upon customer reaction to the roll-out and the availability of testimonials.

MITIGATING RISKS AND CHALLENGES

To manage expectations and address customer concerns, our team recognizes the need to put ourselves in the place of our customers. This allows us to be fully prepared to anticipate and respond to situations that could affect customers, stakeholders, or the community during smart meter deployment. We realize the introduction of new technology, logistics of the installations, and transition to using smart meters will mean that we need to help customers manage through the change and help them use their data to make decisions that will save energy and money.

Anticipating Key Issues

While individual customer issues will receive attention, we will also track issues on a broader scale. SPS will actively monitor sources where customer issues or concerns may originate including, but not limited to:

- Customer Care Call Centers (both residential and business inquiries)

- Inquiries to company executives, regional leaders, and front-line managers
- Inquiries to field and other employee personnel
- SPS's Community Affairs, Key Account Management, and State and Government Affairs teams
- Media Relations
- NMPRC staff
- Community groups and consumer advocacy groups
- Letters, phone calls, social media posts, and emails from customers

Addressing Concerns

We will use existing processes and procedures for handling issues escalated through our Customer Care team. Our communication materials will attempt to address key issues and possible smart meter concerns, including but not limited to:

- **Radio Frequency (RF) Emissions**: As smart meters emit low levels of electro-magnetic radiation through their RF communications, SPS will educate customers with the goal of alleviating unfounded concerns around health impacts and interference with other wireless devices.
- **Privacy & Security:** The company will assure customers that we take their data privacy seriously by providing information about our data privacy policies. We will also clearly outline steps we take to protect customers' energy use information and personally identifiable information.
- **Accuracy:** Messages will also address the measurement accuracy of smart meters, and let customers know how to contact us if they have billing questions related to their meter readings. Call center agents will be trained to answer questions and assist customers.
- **Deployment Expectations:** Communications will help make it easy for customers to properly identify our company employees and know what to expect when meter installers are working at their home or business. This includes special instructions for customers with medical conditions that may have equipment in their homes.
- **Opt-Out Policies:** The Company will address opt-out policies for smart meter technology, and let customers know the proper channels for inquiring about available alternatives.
- **Fixed and Low-Income Customers:** Customized communications will recognize and proactively address cost concerns among low-income households, seniors, and vulnerable customer populations. We will seek to engage community leaders, influencers, and representatives of these communities in the development and deployment of our educational efforts. Messages will address how customers on fixed or limited budgets can take advantage of personal energy use information that may allow them to better manage their energy costs. Outreach will also focus on increasing these customers' participation rates in energy efficiency and conservation programs, and cross-marketing New Mexico's low-income assistance programs. Communication and education materials that could be customized for this segment of customers may include:

    - FAQs and fact sheets addressing their specific concerns and needs.
    - Talking points and scheduled briefings with consumer advocacy groups and nonprofit groups who serve these populations.
    - Customized presentations for community area managers to share with their constituents.

  - Aggressive outreach to organizations serving seniors, low-income, and other vulnerable customer segments, with an emphasis on providing ready-to-use materials that can be distributed via their communication channels, online resources, events, meetings, and social media platforms.

- **Non-English-Speaking Customers:** The company's service area includes a diverse audience. Marketing collateral and communications will be created in Spanish whenever possible.