**SCBEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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IN THE MATTER OF ADVICE NO. 1828-	**)**	
ELECTRIC OF PUBLIC SERVICE	**)**	
COMPANY OF COLORADO TO REVISE	**)**	
ITS COLORADO P.U.C. NO. 8 -	**)**	**PROCEEDING NO. 20AL-XXXXE**
ELECTRIC TARIFF TO IMPLEMENT AN	**)**	
ADVANCED GRID RIDER TO BE	**)**	
EFFECTIVE ON AUGUST 17, 2020	**)**	

<u>DIRECT TESTIMONY AND ATTACHMENTS OF CHAD NICKELL</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

July 17, 2020

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

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IN THE MATTER OF ADVICE NO. 1828-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 - ELECTRIC TARIFF TO IMPLEMENT AN ADVANCED GRID RIDER TO BE EFFECTIVE ON AUGUST 17, 2020	**) PROCEEDING NO. 20AL-XXXXE**

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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
AGIS CPCN Proceeding	Proceeding No. 16A-0588E
AGIS CPCN Settlement	Unopposed Comprehensive Settlement Agreement approved in Proceeding No. 16A-0588E
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
Business Systems	Business Systems Business Area
CPCN	Certificate of Public Convenience and Necessity
CPCN Projects	AMI, IVVO, and the components of the FAN that support these components
DERs	Distributed Energy Resources
Distribution	Distribution Business Area
FAN	Field Area Network
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location Isolation System Restoration
FLP	Fault Location Prediction
GIS	Geospatial Information Systems
HAN	Home Area Network
IT	Information Technology
IVVO	Integrated Volt-VAr Optimization
kW	Kilowatt
kWh	Kilowatt Hours
LBNL	Lawrence Berkeley National Laboratory

Acronym/Defined Term	**Meaning**
LTCs	Load Tap Changers
NIC	Network Interface Cards
Non-CPCN Projects	ADMS, FLISR, FLP and APT projects, and the non-CPCN FAN, that were undertaken as ordinary course of business
O&M	Operations and Maintenance
OMS	Outage Management System
Public Service	Public Service Company of Colorado
RFP	Request for Proposal
ROW	Right of Way
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SVC	Secondary Static VAr Compensators
VAr	Volt-Ampere reactive
WAN	Wide Area Network
WiMAX	Worldwide Interoperability for Microwave Access
WiSUN	Wireless Smart Utility Network
Xcel Energy	Xcel Energy, Inc.
XES	Xcel Energy Services Inc.

**BEFORE THE PUBLIC UTILITIES COMMISSION
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IN THE MATTER OF ADVICE NO. 1828-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 - ELECTRIC TARIFF TO IMPLEMENT AN ADVANCED GRID RIDER TO BE EFFECTIVE ON AUGUST 17, 2020	**) PROCEEDING NO. 20AL-XXXXE**

DIRECT TESTIMONY AND ATTACHMENTS OF CHAD S. NICKELL

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

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. 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 Inc. ("Xcel Energy") and provides an array of support services to Public Service Company of Colorado ("Public Service" or the "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

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. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my testimony in my Statement of Qualifications.

Q. PLEASE DESCRIBE THE AGIS INITIATIVE AND DISTRIBUTION'S ROLE IN PROVIDING SUPPORT FOR AGIS IN THIS PROCEEDING.

A. The Company has discussed the AGIS initiative in multiple Commission proceedings but for those that have not had the opportunity to engage on this topic or are new interested parties, AGIS is a long-term strategic initiative that will transform the Company's electrical distribution business by enhancing security, efficiency, and reliability, which will enable Public Service to safely integrate more distributed energy resources ("DERs"), and improve customer products and services.

As I discuss in greater detail in Section II, the technical capabilities of the current grid are limited compared to more advanced grid technologies, and the overall system as presently configured is opaque—meaning the Company has little near real-time insight into the grid beyond the substation level. AGIS seeks to take advantage of existing advanced technology to increase grid reliability, transparency, efficiency, and access. Overall, the AGIS platform consists of multiple projects that will ultimately work together to support improved distribution technology, empowered customer choice, and improved energy management and savings.

The Company's AGIS initiative involves the following foundational projects: AMI metering Infrastructure ("AMI"); Advanced Distribution Management System ("ADMS"), including the Geospatial Information System ("GIS"); Integrated Volt-VAR Optimization ("IVVO"); Fault Location Isolation Service Restoration ("FLISR"), including Fault Location Prediction ("FLP"); the Field Area Network ("FAN"); and the Advanced Planning Tool ("APT"). Each of these projects involves a coordinated approach – i.e., planning, design, build, deployment and ongoing support from the Distribution and Business Systems Business Areas.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to support the Company's request for Distribution capital and operations and maintenance ("O&M") cost recovery for the AGIS initiative through establishment of a rider mechanism or the Advanced Grid Rider ("AGR"). To support this request, I provide an overview of the AGIS initiative and the need for this initiative. I also explain and support the Company's proposed implementation of, and capital and O&M forecasts for, the Distribution components of the AGIS initiative. Company witness Mr. Steven P. Berman discusses the policy aspects of the AGIS initiative for this rider filing and Company witness Mr. Wendall A. Reimer supports the Business Systems' implementation of the AGIS projects.

Since the Company previously received a Certificate of Public Convenience and Necessity ("CPCN") for certain components of the AGIS initiative in Proceeding No. 16A-0588E, and further discussed other components in the Company's 2019 Phase I Electric Rate Case (Proceeding No. 19AL-0268E), I provide updated information for each of the projects mentioned above. Specifically, my testimony supports the prudence of Distribution's costs related to both the CPCN projects (AMI, IVVO, and the associated mesh network portion of the FAN), as well as the overall prudence of the non-CPCN projects (ADMS, FLISR, FLP, and APT projects, and the non-mesh portions of the FAN, that are undertaken as ordinary course of business) that are planned at this time, and the prudence of the Company's current and ongoing implementation of the foundational components of the AGIS initiative.

I also support the current Distribution capital and O&M forecasts for all foundational components of the AGIS initiative through 2025, when implementation of these foundational components is expected to be complete. Overall, my Direct Testimony is intended to support the Company's request for cost recovery for these projects through the proposed AGR.

Q. HOW IS THE TECHNICAL DISCUSSION OF THE VARIOUS AGIS PROJECTS DIVIDED BETWEEN YOUR DISTRIBUTION TESTIMONY AND MR. REIMER'S BUSINESS SYSTEMS TESTIMONY?

A. Since most of the benefits of the AGIS 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 project. I also provide primary support for the costs and implementation related to the AMI meters, procurement and installation of FAN devices installed on the distribution system, the procurement and installation of the intelligent field devices required for IVVO and FLISR, Distribution's need for the APT, and Distribution investments in substation communication.

Mr. Reimer will focus on the information technology ("IT") integration necessary to implement these projects. While the AGIS initiative is implemented in partnership with Business Systems some components of the AGIS initiative – like ADMS, the AMI head-end system and HAN capabilities, and the FAN private network – Business Systems has primary responsibility for implementing projects. Where the Business Systems Business Area has primary responsibility for the project's implementation, I defer to Mr. Reimer, as set forth in Table CSN-D-1 below.

Table CSN-D-1: AGIS Project Witness Support

AGIS Project	Component	Witness
AMI	Meters and deployment	Nickell Direct, Section IV
	IT Integration and head end application	Reimer Direct, Section III
ADMS	Geospatial Information Systems	Nickell Direct, Section V
	ADMS system and integration	Reimer Direct, Section IV
IVVO	Advanced application and field devices	Nickell Direct, Section V
	System development	Reimer Direct, Section V
FLISR	Advanced application and field devices	Nickell Direct, Section VI
	System development	Reimer Direct, Section XX
FAN	Installation of pole-mounted devices	Nickell Direct, Section VII
	IT Integration and deployment	Reimer Direct, Section VIII
APT and Other	Advanced Application	Nickell Direct, Section VIII
	System Development	Reimer Direct, Section VII

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring Attachments CSN-1 through CSN-4, which were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment CSN-1: Distribution AGIS Capital Additions for 2019-2025;
- Attachment CSN-2: Distribution AGIS O&M Expenses by Cost Element for 2020-2025;
- Attachment CSN-3: Distribution AGIS O&M Expenses by FERC Account for 2020-2025; and
- Highly Confidential Attachment CSN-4 and Public Attachment CSN-4: Highly confidential and public versions of AMI Request for Proposals (RFP) Results Summary.

II. OVERVIEW OF DISTRIBUTION TESTIMONY

A. Distribution's Work on AGIS

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

A. In this section of my testimony, I will provide an overview of the foundational AGIS projects and prior Commission proceedings and approvals related to the AGIS projects. I will also discuss the work that Distribution has completed related to the AGIS projects and provide an overview of Distribution's AGIS capital and O&M costs.

Q. PLEASE PROVIDE AN OVERVIEW OF THE AGIS PROJECTS.

A. Below is a brief overview of each of the AGIS projects:

- *AMI:* AMI meters are able to measure and transmit voltage, current, and power quality data and can act as a "meter as a sensor," enabling ADMS to engage in near real-time monitoring of the distribution system. These meters provide information about customer usage and will enhance the Company'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 disconnects and reconnects. AMI meters will replace existing Automated Meter Reading ("AMR") meters with more advanced technology to improve service and reliability.

- *ADMS:* 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 IVVO and 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 GIS project (described below) and manages each of the other AGIS components described below.

- *GIS:* GIS is a geospatial project that provides location information about all physical assets that make up the Company's electric distribution system. The records also include specifications regarding the physical assets, such as a distribution feeder's size. While the Company already has a GIS, the Company has been engaging in a data gathering effort to validate and update the information in GIS because the ADMS model needs enhanced data accuracy to operate effectively. ADMS uses the GIS' location and specifications to maintain the as-operated electrical model and advanced applications.

- *IVVO:* IVVO is an application that automates and optimizes the operation of the distribution voltage regulating and VAr control devices. The operation of IVVO includes the ADMS software and automated field devices that automate the voltage control of distribution feeders and reduce electrical losses, electrical demand, and energy consumption, and provides increased distribution system injection capacity to host DER.

- *FLISR:* FLISR involves the ADMS 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 the Company's substations, the ADMS and the AMI software systems, the new AMI meters, and the new intelligent field devices associated with advanced applications such as IVVO and FLISR. The FAN provides benefits to all AGIS projects, but is designed and built according to the needs of various specific components, and each has different communication network requirements.

- *APT and Other:* The APT is a spatial load forecasting tool, which combines several layers of detailed electric infrastructure, weather, economic and other data to forecast how load and energy demands on the grid may change in the future. APT is a foundational planning tool that will enhance system reliability as well as supporting modernization of our distribution system. APT will replace our current planning tool that lacks the ability to provide the data granularity and transparency necessary to keep pace with customer expectations and evolving regulatory requirements. For example, the current planning tool can only provide forecast information at the feeder and substation level and lacks the ability to measure two-way power flows that is needed to allow us to understand the grid impacts of varying levels of DER adoption. The "Other" cost capital category for Distribution also includes investments in substation communication upgrades.

Q. WHAT COMMISSION APPROVALS HAS PUBLIC SERVICE RECEIVED RELATED TO THE AGIS INITIATIVE?

A. On August 2, 2016, Public Service filed an Application and Direct Testimony in Proceeding No. 16A-0588E (the "AGIS CPCN Proceeding"), requesting that the Commission grant a CPCN to implement AMI, IVVO, and the associated mesh network portion of the FAN (collectively, the "CPCN Projects"). The Commission approved the Company's request for a CPCN pursuant to its Application as part of an AGIS CPCN Settlement between the parties in the CPCN Proceeding (the "AGIS CPCN Settlement").1 Company witness Mr. Steve P. Berman discusses the AGIS CPCN Settlement in greater detail. Mr. Berman also discusses the Company's subsequent application and the Commission's approval of Public Service's plan to activate the Home Area Network ("HAN") capability within the AMI meters in Proceeding No. 18A-0194E (the "HAN Proceeding").

Q. WHAT IS THE DISTRIBUTION BUSINESS AREA'S ROLE OF THE IN IMPLEMENTING THE AGIS FOUNDATIONAL PROJECTS?

A. At a high level, the work that the Distribution Business Area will undertake falls into

[1] Unopposed Comprehensive AGIS CPCN Settlement in Proceeding No. 16A-0588E.

six primary categories: (1) installing field devices (AMI meters, and field devices to implement IVVO, FLISR, FLP); (2) data collection for ADMS and GIS; (3) supporting the business requirements and the required testing in support of the software deployments; (4) managing and supporting the governance structure; (5) determining appropriate business processes to manage the systems; and (6) determining employees' roles and responsibilities to implement and operate the new projects that are part of the AGIS initiative. The last three categories I identified (4 through 6) are both part of Project and Change Management to ensure a successful implementation, which are discussed separately in Section X and comprise a part of each AGIS project.

Q. WHAT WORK HAS DISTRIBUTION ALREADY UNDERTAKEN OR COMPLETED WITH RESPECT TO THE AGIS INITIATIVE?

A. As previously noted, the Company previously obtained a CPCN for the AGIS CPCN Projects in 2017. Before and after the CPCN was obtained, Distribution has been working on the planning and implementation of the various components of the AGIS initiative. Public Service has undertaken scoping, planning, design, requests for proposal ("RFP"), and contracting with respect to a number of the components. Further, consistent with the AGIS CPCN Settlement in the CPCN Proceeding, Public Service is already deploying and operating some components and facets of the AGIS initiative. For example, the first deployment phase of ADMS was placed in service in April 2019 with the second, and final deployment planned for the fourth quarter of 2020. Public Service has also deployed IVVO field devices and 13,000 AMI meters and portions of the FAN to support AMI and IVVO. In the coming years, the Company will begin a mass deployment of 1.6 million AMI meters to all of Public Service's electric customers and will continue to add capabilities and functionality to AMI through interfaces and customer systems to deliver more value to customers. Public Service has also started to deploy FLISR and FLP devices on some of the lowest performing feeders within the Company's service territory and those devices have begun to be used to provide reliability benefits to customers.

B. Introduction to Distribution's AGIS Costs

Q. HOW ARE DISTRIBUTION'S AGIS COSTS PRESENTED IN YOUR TESTIMONY?

A. AGIS capital expenditures, capital additions, and O&M costs are stated for the Public Service electric utility and are denoted by the term "Total Company." I will provide costs to date, as well as costs planned for the remainder of each of the projects.

Q. WHAT TYPES OF CAPITAL COSTS IS DISTRIBUTION INCURRING TO IMPLEMENT THE AGIS INITIATIVE?

A. The capital costs for Distribution to implement each of the AGIS projects (AMI, GIS data collection in support of ADMS, FAN, FLISR, IVVO, and substation communications) generally include material and equipment, labor, and vendor services.

Q. WHAT ARE THE DISTRIBUTION CAPITAL COSTS FOR THE AGIS INITIATIVE THAT YOU ARE SUPPORTING IN THIS PROCEEDING?

A. Distribution's AGIS capital expenditures and capital additions that I am supporting for rider recovery are shown in Tables CSN-D-2 and in Table CSN-D-3 below. These costs are forecasts (with the exception of 2019, which are actual costs) intended to illustrate the scope of projected costs, subject to annual forecasts and true-ups through the AGR as described by Company witness Mr. Berman. The capital costs in the "Other" category relate to substation communication improvements that I discuss below in Section X.

Table CSN-D-2
AGIS Distribution - Capital Expenditures
(Total Company)
(Dollars in Millions)

Project	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
AMI	5.77	3.07	69.40	78.44	67.99	19.87	0.0
ADMS	3.96	2.67	0.0	0.0	0.00	0.0	0.0
IVVO	16.97	24.39	24.68	22.94	8.0	1.70	0.0
FLISR	4.71	5.60	6.19	6.63	7.75	6.67	6.67
FAN	9.25	4.73	5.79	3.18	3.18	2.15	0.0
Other	0.12	1.91	2.95	3.55	9.95	4.5	0.0
Total	**40.78**	**42.37**	**109.01**	**114.74**	**96.87**	**34.89**	**6.67**

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

Table CSN-D-3
AGIS Distribution - Capital Additions
(Total Company)
(Dollars in Millions)

Project	2019	2020	2021	2022	2023	2024	2025
AMI	7.52	0.87	69.70	74.99	65.00	19.00	0.00
ADMS	5.33	2.77	0.00	0.00	0.00	0.00	0.00
IVVO	26.33	27.57	24.98	22.87	8.05	1.75	0.00
FLISR	15.54	5.16	5.96	6.47	8.05	6.54	6.60
FAN	10.06	5.64	5.89	3.18	3.18	2.15	0.00
Other	0.40	1.62	2.79	3.19	10.90	4.50	0.00
Total	**65.18**	**43.62**	**109.31**	**110.70**	**95.17**	**33.93**	**6.60**
*There may be differences between the sum of the individual AGIS project amounts and total amounts due to rounding.							

Total AGIS Distribution capital additions are also set forth in Attachment CSN-1 to my Direct Testimony. I provide additional details and support for Distribution's capital costs below, organized by AGIS project.

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

A. Distribution's AGIS related O&M costs include external labor, vendor services, and materials. All internal labor costs have been excluded as they are reflected in base rates.

Q. WHAT IS DISTRIBUTION'S FORECASTED O&M COSTS FOR AGIS IMPLEMENTATION?

A. The forecasted AGIS O&M expenses for Distribution are shown in Table CSN-D-4. 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 AGIS Rider as described by Company witness Mr. Berman. The O&M costs in the "Other" category relate to costs associated with program management, change management, delivery and execution leadership, and corporate communications which I discuss in Section X.

Table CSN-D-4
AGIS Distribution - O&M Expenses
(Total Company)
(Dollars in Millions)

Project	2021	2022	2023	2024	2025
AMI	3.54	0.57	0.47	0.32	0.22
ADMS	0.28	0.24	0.29	0.29	0.29
IVVO	0.65	0.39	0.00	0.00	0.00
FLISR	0.32	0.58	0.61	0.63	0.64
FAN	0.46	0.50	0.52	0.53	0.26
Other	2.17	2.05	1.10	1.10	0.97
Total	**7.42**	**4.35**	**2.99**	**2.88**	**2.38**

Total AGIS 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 AGIS component.

Q. YOU STATED THAT THE COMPANY HAS PREVIOUSLY RECOVERED A PORTION OF AGIS COSTS IN THE 2019 RATE CASE. PLEASE ELABORATE.

A. The costs presented in Tables CSN-D-2 to CSN-D-4 above are indicative of the overall costs of the AGIS initiative. As Company witnesses Mr. Berman and Ms. Blair explain, certain AGIS capital additions placed in service in 2019 and O&M costs related to these capital additions, as well as internal labor, are included in base rates as a result of the Company's 2019 Phase I Electric Rate Case. (“2019 Electric Rate Case”). Company witnesses Mr. Berman and Ms. Blair detail the adjustments that will be made to the revenue requirements in this proceeding to account for O&M and capital additions that were previously recovered in the 2019 Electric Rate Case.

III. DRIVERS OF AGIS INITIATIVE

Q. WHAT IS THE PURPOSE OF THIS PORTION OF YOUR DIRECT TESTIMONY?

A. While Public Service discussed the need for the AGIS initiative in depth in the approved CPCN Proceeding and we are not proposing to relitigate that here, in this section of my testimony for the Commission's and the intervening parties convenience, I provide a summary of the key drivers for the AGIS initiative and provide additional details about the benefits these projects will provide to Public Service's customers.

Q. HOW WAS PUBLIC SERVICE'S DISTRIBUTION SYSTEM ORIGINALLY DESIGNED, AND HOW DOES THIS DESIGN LIMIT THE CAPABILITIES AND OPERATION OF THE SYSTEM?

A. Public Service'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 the Company has regarding the workings of the system and the customer experience beyond the distribution substation level. The system was also designed to rely heavily on manual and local control configurations to operate 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 THE LACK OF 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 distribution system (primarily at substations), the Company has little insight into the flow of power, voltages, and the operation of equipment on the system beyond the substation. Thus, the Company has little insight into the customer experience – the voltage that the customer is receiving, whether the power is out or has been restored, or any abnormality that might be detectable. To obtain information regarding the numerous distribution system components beyond the substation, such as meter readings, current flow, or voltage levels, the Company has to send workers out into the field to gather this information.

Q. HOW DOES THIS LACK OF VISIBILITY BEYOND THE SUBSTATION LEVEL IMPACT THE COMPANY'S ABILITY TO IDENTIFY OUTAGES?

A. Since the Company does not have visibility into the system beyond the substation level, we rely on customers notifying us via phone or website/app of outages. The Outage Management System ("OMS") then aggregates the outage call information and determines which portion(s) of the distribution system lost power. Once the portion of the system that is out is identified, the Company 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 LACK OF VISIBILITY IMPACT THE COMPANY'S ABILITY TO MONITOR AND CONTROL VOLTAGE LEVELS ON THE SYSTEM?

A. Because the Company does not have visibility into the system beyond the substation level, the Company 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, we rely on customers to report either high or low voltage issues. To maintain required voltage levels, the Company keeps the voltage level at the substation at the high end of the appropriate voltage level at all times. This helps ensure that under any conditions the last customer on the system will have voltage within the acceptable range. However, operating the system at higher voltage levels is more costly as it uses more energy, and many end use devices do not operate efficiently at higher voltage levels.

Q. HOW DOES THE LACK OF VISIBILITY IMPACT THE DISTRIBUTION SYSTEM'S ABILITY TO ACCOMMODATE DISTRIBUTED GENERATION?

A. The Company does not have the ability to accurately measure the amount of distributed generation that is flowing onto or leaving the system. Rather, the system relies on conservative estimates to quantify the amount of distributed generation entering and leaving the grid. Because the Company 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. This is 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 there are high levels of distributed generation 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. Should this occur, there is a risk that a faulted portion of the system would remain energized and present a hazard. While Colorado currently has low levels of distributed generation relative to some other states, it will be important for the distribution system to have the capability to accommodate increasing levels in the future as more distributed generation is added to the system.

Q. HOW DOES THE LACK OF VISIBILITY AND INFORMATION IMPACT THE CUSTOMER EXPERIENCE?

A. The current automated meter reading ("AMR") system is largely limited to providing the Company with customer usage information necessary to support customer billing. As a result, we cannot provide customers with timely power usage information to enable them to manage their electric usage more efficiently. Additionally, the AMR meters do not have the capability to communicate information to the Company about issues with the system such as an outage or voltage issue, therefore we still rely 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. The current distribution system's operation relies on mostly manual and local control schemes that require human intervention to complete an operation. For example, field switches for nearly all feeders are manually operated switches. 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 immediate upstream and downstream connecting switches to isolate the faulty feeder section. Then, after the faulted section of the feeder is repaired, the switches are manually closed to restore service to the feeder. Automating this process will reduce customer outage durations, enable quicker responses to faults, and reduce crew field time.

C. <u>Limited Connectivity</u>

Q. HOW DOES THE COMPANY CURRENTLY COMMUNICATE WITH SUBSTATIONS, FIELD DEVICES, AND METERS?

A. For many years, the Company has communicated with its substation through leased telephone circuits with widely varying capabilities, especially in rural areas, or through expensive microwave installations. Connecting field devices (switches, etc.) with communications networks has been limited due to the expense and complexity of managing these circuits. Although the Company 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 advanced applications cannot be supported with the Company's current communication network. These improvements will allow the Company access to information to better manage the system and respond to outages, and to provide our 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.

D. Public Service's Vision for the Future of the Distribution Grid

Q. PLEASE DESCRIBE PUBLIC SERVICE'S VISION FOR THE FUTURE OF THE DISTRIBUTION GRID.

A. The Company's vision for the future distribution grid is one that utilizes advances in technology to improve our monitoring and operation of the grid for the benefit of our customers. The AGIS investments will provide Public Service 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 have the necessary automation and intelligence to address any problems quickly and efficiently. In some cases, these insights will alert the Company 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 the Company with the necessary information to continually monitor and make the necessary adjustments to the system to support increasing amounts of DER and other electric technologies such as electric vehicles.

Additionally, 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.

IV. ADVANCED METERING INFRASTRUCTURE

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 the progress that Public Service has made in the development and implementation of AMI since the approval of AMI in the AGIS CPCN Proceeding (Proceeding No. 16A-0588E). This progress includes the selection of a metering vendor and recent developments in the AMI meter technology. Then, I address Distribution's implementation plan for the AMI project. Finally, I discuss Distribution's capital and O&M forecasts for the AMI project, identifying the components of each of these costs and how these cost forecasts were developed.

A. Overview of AMI

Q. WHAT IS THE AMI PROJECT?

A. AMI is an integrated system of AMI meters, communications networks, and data management 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 the AGIS initiative because it provides a central source of information that interacts with many of the other components of the AGIS initiative.

Q. HOW DOES THE AMI PROJECT BENEFIT CUSTOMERS?

A. AMI meters provide substantial near real-time data that can be used to improve the Company's ability to monitor, operate, and maintain the distribution grid. AMI meters are used to verify power outages and service restoration. Improved reliability monitoring leads to improved outage response, proper protection system analysis and ultimately reduces or eliminates 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 with applications like IVVO that promote energy efficiency and demand reduction. AMI meters are also able to support new rate designs that cannot be supported by the Company's legacy meters, such as the rates resulting from the Company's Residential Energy Time-of-Use filing, Proceeding No. 19AL-0687E, in which the Company and intervenors reached a settlement agreement filed on June 11, 2020. 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</u>

Q. AT THE TIME OF THE AGIS CPCN SETTLEMENT, THE COMPANY WAS STILL EVALUATING DIFFERENT AMI METER VENDORS. HAS THE COMPANY COMPLETED THIS EVALUATION AND SELECTED A METER VENDOR?

A. Yes, the Company 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 are described in greater detail below. I note that a different AMI meter, a Landis+Gyr Focus meters equipped with Itron Gen 5 network interface cards ("NICs"), were installed in support of IVVO in 2019 because the Riva Generation 4.2 AMI meter will not be ready for installation until 2021. These 13,000 meters installed to support IVVO will be replaced by Itron with the Riva Generation 4.2 during the mass deployment at no cost to Public Service. A photo of a meter (the OpenWay® Riva CENTRON meter) similar to the Itron Riva Generation 4.2 AMI meter is provided in Figure CSN-D-1 below. A photo of the Riva Generation 4.2 meter is not currently available.

Figure CSN-D-1
AMI Meter Similar to the Riva Generation 4.2

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); (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 the Company's legacy meters – to measure the amount of electricity used by our customers for billing purposes. However, the 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 the Company to the customer and also measures net energy provided from customers (i.e., customers with solar panels) to the Company. 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 THE COMPANY?

A. The AMI meters will collect and transmit data to the Company 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 employee may request and collect the meter data while on the phone assisting a customer.

- Through the customer portal or smartphone application, as described by Mr. Reimer, a customer could request an on-demand meter reading. This request will provide a customer with near real-time energy information.[2]

- AMI meters will transmit data when an event occurs such as a power outage, power restoration, power quality event, or a diagnostic event. The length of time between the data transmission and the event depends on the type of the 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

[2] The term "near real-time" refer 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.

- Support remote connect and disconnect functions[3] for customers taking single-phase service (generally, residential and some small business customers).[4]

Q. BEYOND SUPPORTING IVVO, HAS THE COMPANY REALIZED BENEFITS FROM THE INITIAL 13,000 AMI METERS THAT HAVE BEEN DEPLOYED TO DATE?

A. Yes, examples of benefits include:

- Safety Enhancement and Damage Notification: In January 2020, the Company's Metering group received a high temperature alarm from AMI meters in an apartment complex that was the result of a fire started by an individual. While the proper authorities were already aware and responding to the fire, the Company was able to perform timely repairs and replacements of the damaged AMI meters when it was safe to do so. Under the current AMR technology, the Company would not have known about this issue until notified by a customer or until the Company identified the issue when reviewing the billing cycle information.

- Safety Enhancement: The AMI meters send a notification when power is flowing from the customer onto the distribution system (that can be the result of on-site solar for instance). The Company has been able to identify several on-site solar installations that had been connected at customer premises but have not been approved through the interconnection process. In instances like these, the Company will contact the customer and guide customers through the interconnection process and ensure proper, safe installation of solar facilities.

- Tampering and Theft: The fact that power is flowing from a customer premise unto the distribution system can also be a sign of meter tampering. Since the AMI meters send a notification when power is flowing from the customer onto the distribution system, the Company has been able to identify a few instances of meter tampering based on these notifications.

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[3] Public Service will continue to abide by the Commission's rules as well as the Company's tariff regarding the steps that will be taken by the Company prior to disconnection. Public Service's procedures for discontinuation of service for Residential and Small Commercial customers are outlined in on Tariff Sheet R56 of the Company's Electric Tariff. Public Service also recognizes that the Settlement Agreement sets forth certain requirements related to remote connection/disconnection.

[4] 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 the Company'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 the Company, there is also a second radio within the meter that is Wi-Fi compatible and can be configured to communicate with a customer's HAN and HAN 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. HAS THE COMPANY'S PLAN TO ENABLE COMMUNICATIONS BETWEEN THE AMI METER AND THE HAN CHANGED SINCE THE HAN PROCEEDING?

A. Yes. At the time of the HAN Proceeding, it was anticipated that the AMI meters would communicate with a customer's HAN using a ZigBee radio within the AMI meter. Since that time, AMI meter technologies have continued to evolve, and the Company has continued to engage with the AMI meter manufacturer to develop the software-defined radio solution that will enable AMI meters to support HAN. Based on this continued evaluation, the Itron AMI meters that will be deployed will support HAN capabilities via a Wi-Fi compatible radio as opposed to a ZigBee radio.

Q. WHAT ARE THE ADVANTAGES OF USING WI-FI COMMUNICATIONS OVER A ZIGBEE RADIO IN THE AMI METERS?

A. As discussed in greater detail in the testimony of Company witness Mr. Reimer, the shift to Wi-Fi benefits the customer's experience because most customers already own Wi-Fi enabled devices. This eliminates the need for a customer to purchase a secondary device with a ZigBee radio to connect to their meter.

Q. HOW WILL CUSTOMERS BE ABLE TO CONNECT THEIR HAN DEVICES TO THE AMI METERS?

A. As discussed in the HAN Proceeding, Public Service will allow customers to "bring your own device." 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 and the Company 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 will involve customers submitting an activation request for their HAN devices and the Company processing that request and activating the NIC within the AMI meter to communicate with the customer's HAN device.

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 Company's FAN it reduces the strain on the network (for other uses of AMI, FLISR, and IVVO for example) and improves the computational speed, efficiency, and capabilities derived from these platforms. Distributed intelligence capabilities in AMI meters and other edge devices opens up a broad array of new uses that will transform how customers will use energy in their homes and businesses, as well as how Public Service will be able to optimize its AGIS investments.

Q. WHAT ARE THE EMBEDDED DISTRIBUTED INTELLIGENCE CAPABILITIES OF THE AMI METER SELECTED BY THE COMPANY?

A. The Company's AMI meters will provide a distributed intelligence platform that is essentially a computer within the meter at customers' homes and businesses. This computer uses a Linux-based operating system to conduct localized, at-the-meter computing, analysis, and data processing that provide customers with new tools to help manage their energy usage and provide Public Service with new tools to manage the grid more efficiently. This capability also allows for the installation of a wide-range of potential applications. In other words, this DI capability allows for the installation of applications on the meter – similar to how applications are installed on a smart phone. These applications may be customer-facing, meaning the customer directly interacts with them, or grid-facing, meaning Public Service interacts with the applications.

Q. WHAT ARE THE POTENTIAL USES OF DI CAPABILITY?

A. The DI capabilities allow the AMI meter to run multiple applications at the same time and without the need for instructions from the Company's back-office applications or control room. This type of capability is beneficial because it allows the AMI meters to communicate directly with each other regarding issues, analyze those issues, and solve problems directly rather than communicating these issues to a back-office system and then waiting for instructions on how to solve the problem. The potential use cases for these applications include:

- Improved security and awareness,
- Energy usage control and savings,

- Smarter insights about customer energy data and information,
- Smarter controls to better manage and integrate different systems, and
- Identification and alarming for operational issues.

Q. PLEASE PROVIDE AN EXAMPLE OF HOW THESE DISTRIBUTED INTELLIGENCE CAPABILITIES COULD BE USED BY THE DISTRIBUTION ORGANIZATION.

A. Public Service is leading the nation to deploy DI in the AMI meters. As a leader in this space, the Company is working with Itron to design, develop, and implement new applications. Itron has already begun building a number of applications that can be enabled on the meter. While the specific use of these DI capabilities will depend on the particular applications employed, how these capabilities could be utilized to manage demand during peak times to avoid transformer overloads. For example, during a hot summer afternoon when energy use is rising due to air conditioning use, the AMI meters at each customer location would analyze this data in real time. These meters would then share their individual data with the other meters served by a common distribution transformer, calculating and comparing the total load to the capacity of the transformer. The AMI meters would be able to discern when the transformer is approaching overload conditions and determine the most appropriate course of action, which could be reporting, alarming, modulating, or possibly shutting off controllable loads to keep the transformer below its rated capacity. The same concept would help with the integration of electric vehicles and solar, as well.

Q. WHAT PORTION OF THE HAN AND DI COSTS ARE INCLUDED IN THE COSTS THAT THE COMPANY IS SEEKING TO RECOVER THROUGH THE AGR?

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 AGR costs. The additional costs for HAN and DI including software applications and backend systems are not included in the AGR costs.

Q. WHAT COSTS FOR GREEN BUTTON CONNECT ("GBC") ARE INCLUDED IN THE COSTS THAT THE COMPANY IS SEEKING TO RECOVER THROUGH THE AGR?

A. At this time, no GBC costs have been included for recovery. The Company is currently scoping and developing the GBC program and does not have a final determination of the costs to deliver the service.

Q. LASTLY, WHAT IS THE PURPOSE OF THE INTERNAL SERVICE SWITCH?

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. Public Service is not requesting any changes to its disconnection procedures as part of this proceeding.

Q. WHAT IS THE EXPECTED SERVICE LIFE FOR THE AMI METERS?

A. Public Service 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 more computer-oriented than their former counterparts and are integrated with large software systems it is expected that these AMI meters will have a shorter service life than the current meters. In addition, Public Service 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 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.[5] Other utilities following this approach include Consumers Energy Company in Michigan, ComEd Illinois, Nevada Power, and ConEd New York.[6] Company witness Ms. Laurie J. Wold discusses the depreciation rate for the AMI meters in greater detail.

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

6 *See* Michigan Public Service 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 Public Service 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.

C. AMI Deployment Timeline

Q. PLEASE DESCRIBE THE WORK THAT DISTRIBUTION WILL UNDERTAKE TO IMPLEMENT AMI.

A. Public Service plans to install 1.6 million AMI meters between 2021 and 2024. 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 AMR 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.

Q. WHAT DEPLOYMENT TIMELINE FOR AMI WAS APPROVED AS PART OF THE AGIS CPCN SETTLEMENT?

A. The approved AGIS CPCN Settlement contemplated the deployment of 13,000 AMI meters in 2019 in support of the IVVO project and the full deployment of the 1.6 million AMI meters from 2020-2024.

Q. WHAT IS THE CURRENT STATUS OF THE DEPLOYMENT OF AMI?

A. The deployment of AMI has two components: (1) meter deployment and (2) software deployment. The software deployment is discussed in the Direct Testimony of Mr. Reimer.

Q. PLEASE DISCUSS THE WORK THAT DISTRIBUTION HAS COMPLETED IN SUPPORT OF THE METER DEPLOYMENT.

A. The Company completed the installation of the 13,000 AMI meters between October 16th and December 26th, 2019. Prior to the installation of the meters the

Company performed First Article Testing of the meter accuracy and functional operation, and evaluation of data from the meter through the meter reading and billing systems. First Article Testing is performed on meters containing the Company's requested functionality and configurations, to ensure they meet all specifications as required by the Company. In addition, the Company performed Integration Testing to examine business requirements and functionality across all products, applications, and platforms involved with the AMI meters.

Q. WHEN WILL THE COMPANY COMMENCE DEPLOYMENT OF THE REMAINDER OF THE AMI METERS?

A. While the AGIS CPCN Settlement contemplated that full deployment of AMI would begin in 2020, the Company now anticipates that full deployment will begin in 2021. The Company is currently working with the parties to the AGIS CPCN Settlement to update the meter deployment schedule.

Q. WHY WAS THE START OF THE METER ROLL-OUT DELAYED FROM THE ORIGINALLY PROJECTED START DATE?

A. The Company made the decision to delay deployment of the AMI meters in late March 2019 as Public Service learned that the meter vendor that was initially selected would not be able to integrate the selected NIC and provide distributed intelligence capabilities while also meeting the Company's deployment schedule.[7] In April 2019, the Company solicited additional information from another AMI vendor to evaluate both their NIC integration schedules and the DI capabilities of

7 Public Service discussed these changes to the AMI meter deployment as part of the Company's Annual Forecast Report for 2020 filed on October 31, 2019.

their AMI meter. An evaluation of the distributed intelligence capabilities of different meter vendors was important to future-proofing this technology, as these capabilities will allow the AMI meter to support current and future customer offerings. A more detailed discussion of the Company's process to select the AMI meter vendor is provided below.

This additional evaluation resulted in the Company changing its meter vendor and meant that the Company was not able to execute an AMI meter contract until September 1, 2019. The different meter vendor was able to meet the Company's requested deployment schedule with the necessary NIC integration, offered the necessary meter capabilities, including distributed intelligence, and offered favorable price and contractual terms. The current deployment schedule moves the start of the mass deployment of AMI meters from 2020 to 2021 and is based on the availability of the RIVA 4.2 meters and the timeline to complete First Article Testing meter testing and the integration testing as I will describe in more detail later. The Company still anticipates completing full deployment of all AMI meters in its electric service territory by 2024, as contemplated by the AGIS CPCN Settlement. The decision to delay the deployment of the AMI meters, as well as the rationale for the decision, was shared in a meeting with the AGIS CPCN Settlement parties on June 19, 2019. A second meeting was held on September 26, 2019, to provide additional updates to the parties following the signing of the AMI meter contract on September 1, 2019.

Q. CAN YOU PROVIDE AN OVERVIEW OF THE CURRENT AMI DEPLOYMENT TIMELINE?

A. Public Service plans to install approximately 1.6 million AMI meters throughout our Colorado service territory as part of the AGIS initiative starting at the end of the second quarter of 2021. This deployment builds off the limited installation of 13,000 AMI meters that were installed in the southern Denver metro region in 2019 to support IVVO. By the end of 2023, we anticipate that close to 90 percent of the meter installations will be complete. Table CSN-D-6 below provides a summary of the number of meters we anticipate installing per year from 2021 through 2024.

Table CSN-D-6
AMI Meter Installations by Year

Year	**2021**	**2022**	**2023**	**2024**
Approximate Number of AMI Meters Installed	395,000	534,000	504,000	Remainder

Q. PLEASE PROVIDE ADDITIONAL DETAILS REGARDING WHERE THE AMI METERS WILL BE INSTALLED EACH YEAR?

A. Figure CSN-D-2 below depicts the anticipated deployment of AMI meters throughout Public Service's entire service territory. As shown in this figure, the first AMI meters installed as part of mass deployment will be deployed in the southeast Denver metro area beginning the end of second quarter of 2021.[8] This deployment will build on the 13,000 AMI meters that were deployed to support IVVO in 2019 in the southern Denver metro. From there, AMI meter deployment will continue in and around the Denver metro area before completing with the final

[88] Deployment begins the week of June 28, 2021. Therefore, many internal planning documents identify this as Quarter 3 for ease of reference.

areas in 2024. The Company currently anticipates finishing deployment in the fourth quarter of 2024. Figure CSN-D-3 shows detailed breakdown of meter deployments within the Company's electric service territory.

Figure CSN-D-2
AMI Deployment Map for State of Colorado

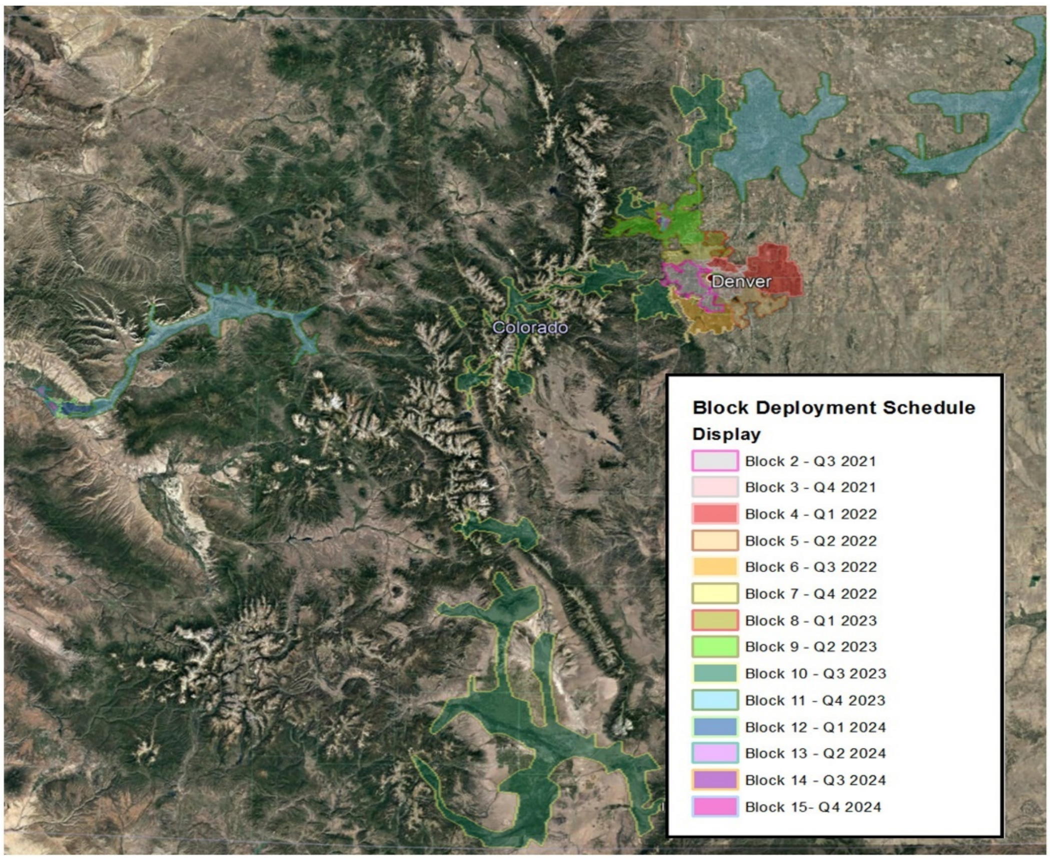
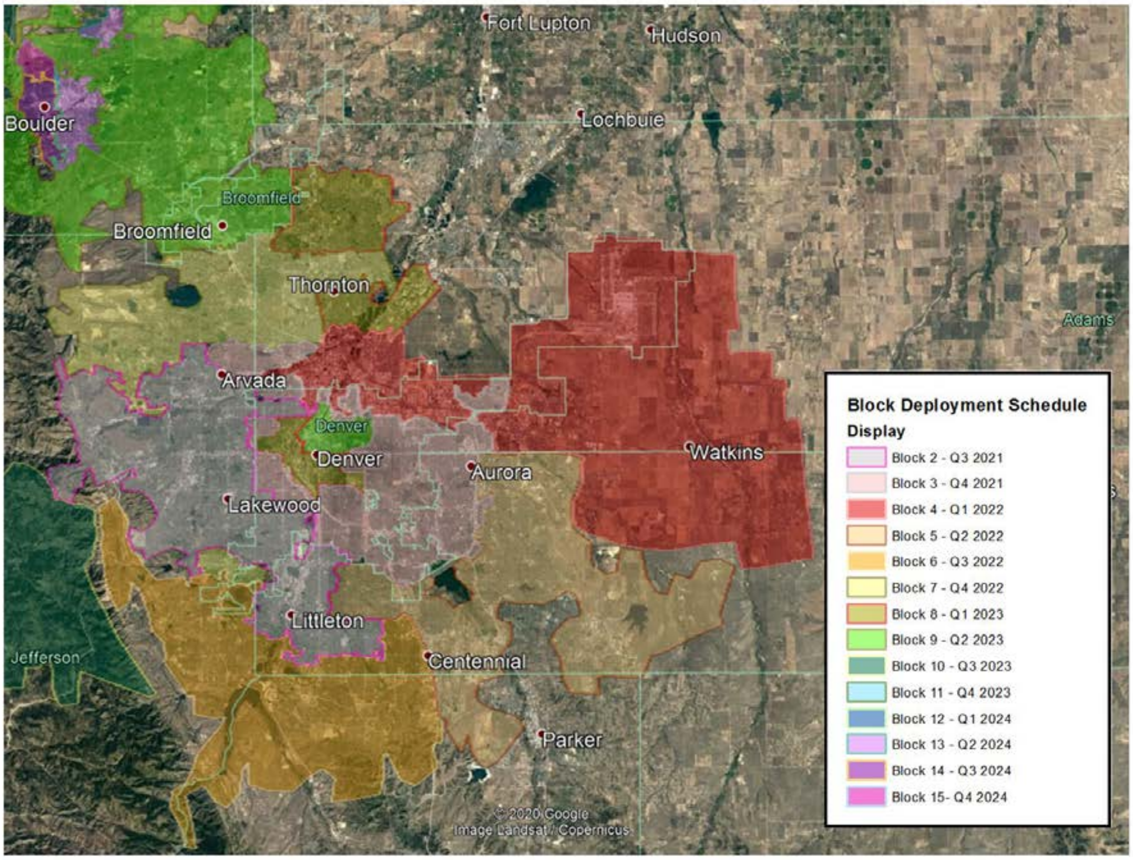


Figure CSN-D-3
AMI Deployment Map for Denver Metropolitan Area



Q. WITH RESPECT TO AMI, WHAT WORK WILL BE COMPLETED BY PUBLIC SERVICE BETWEEN THE TIME OF THIS FILING AND 2024 TO SUPPORT THIS METER DEPLOYMENT SCHEDULE?

A. In 2020, the Company will start testing the Itron Riva Generation 4.2 AMI meter focusing on the electric distribution and customer operational requirements. This meter testing will include 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 Company's requested requirements and configurations, to ensure they meet all specifications as required by the Company. The Company will then perform Integration Testing that examines business requirements and functionality across all products, applications, and platforms involved in the implementation of AMI, from meter to bill. 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, ensuring data quality and accuracy across all systems in scope for AMI. Next, Production Sample Testing will be performed which involves testing a random sample of meters for accuracy, proper operation of the NIC, and the internal switch. Table CSN-D-7 below provides a summary of these testing timelines in support of the first part of the mass deployment of AMI meters in 2021.

Table CSN-D-7
AMI Testing Timeline

Scheduled Milestone	**Timeframe**
Preliminary Testing Single Phase	1st Quarter 2020 to 2nd Quarter 2020
First Article Testing Single Phase	4th Quarter 2020 to 1st Quarter 2021
Integration Testing Single Phase	1st Quarter to 2nd Quarter 2021
Production Sample Test Single Phase	2nd Quarter 2021
Field Deployment to Start Mass Deployment Single Phase	End of 2nd Quarter to 4th Quarter 2021
First Article Testing Poly Phase	3rd Quarter to 4th Quarter 2021
Integration Testing Poly Phase	4th Quarter 2021 to 1st Quarter 2022
Production Sample Test Poly Phase	1st Quarter 2022
Production Sample Test Poly Phase	1st Quarter 2022
Field Deployment to Start Mass Deployment Poly Phase	End of 1st Quarter 2022

Public Service will follow a similar testing schedule for each set of AMI meters in advance of their scheduled deployment between 2020 and 2024.

D. Distribution's Capital Costs for AMI

Q. WAS DISTRIBUTION PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECAST 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 forecasts for the head-end application, other software and hardware to support AMI data processing, and integrations required by those technologies, and Mr. Reimer will address the development of those costs.

Q. WHAT IS THE PROJECTED CAPITAL SPEND FOR THE AMI PROJECT FROM 2020-2025?

A. Tables CSN-D-8 and CSN-D-9 provide a breakdown of Distribution's capital expenditures and capital additions forecast for AMI for 2020 through 2025.

Table CSN-D-8
AMI Distribution - Capital Expenditures
(Total Company)
(Dollars in Millions)

	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
AMI	3.07	69.40	78.44	67.99	19.87	0.0	238.77

Table CSN-D-9
AMI Distribution - Capital Additions
(Total Company)
(Dollars in Millions)

	2020	2021	2022	2023	2024	2025	Total
AMI	0.87	69.70	74.99	65.00	19.00	0.00	229.56

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 our 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. The Company 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 the Company's priorities and vision for its AMI solution including the capabilities desired by the Company 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 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.

Q. HOW MANY COMPANIES RESPONDED TO THE RFP?

A. We received responses to this RFP from four different companies.

Q. HOW DID THE COMPANY EVALUATE THESE RFP RESPONSES?

A. The Company evaluated these responses 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 NIC 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 THE COMPANY DESIRED FOR THE NEW AMI METERS?

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

Q. DID THE COMPANY 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, the Company selected a meter vendor, and issued a Limited Notice to Proceed to that meter vendor in December 2018. However, in late March 2019, the AGIS team learned that the meter vendor that was initially selected would not be able to integrate the selected NIC and provide distributed intelligence capabilities while also meeting the Company's meter deployment schedule set forth in the Limited Notice to Proceed. As a result, the Company requested that the initially selected vendor provide a schedule for deployment for AMI meters that incorporated the vendor's own NIC and network.

Q. WHAT RESPONSE DID THE COMPANY RECEIVE TO THIS REQUEST?

A. The initial meter vendor's response indicated that it would not be able to integrate their own NIC and network into the meters without a significant increase in cost and a risk of further schedule delays. In April 2019, the Company solicited and received a comprehensive proposal from another meter vendor that responded to the initial RFP. This meter vendor was able to meet the Company's requested deployment schedule with the necessary NIC integration, offered the necessary meter capabilities, including distributed intelligence, 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 Public Service, and a contract was executed on September 1, 2019 (the "Meter Contract").

Q. WHY DID THE COMPANY 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 the Company's deployment schedule;
- Single vendor solution (Itron is already under contract for the mesh network and the head-end software);
- Met or exceeded the Company'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 our analysis supporting the selection of Itron is provided as Highly Confidential Attachment CSN-4.

Q. HOW DID DISTRIBUTION DEVELOP ITS CAPITAL FORECAST FOR THE AMI VENDOR PROJECT MANAGEMENT COSTS?

A. The forecast for AMI vendor project management is set forth in the Meter Contract. The Company'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. The Company 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 we leveraged our relationships with existing vendors to obtain the best cost for this equipment.

E. Distribution's O&M Costs for AMI

Q. WHAT IS DISTRIBUTION'S O&M COSTS ASSOCIATED WITH AMI?

A. The primary components of Distribution's AMI O&M expense relate to: (1) support of the capital deployment, (2) business readiness, and (3) change management. As noted above, all internal labor costs have been excluded as these costs are already reflected in base rates. Table CSN-D-10 below provides a summary of Distribution's O&M expense forecast for AMI for 2021 through 2025.

Table CSN-D-10
AMI Distribution – O&M Expenses
(Total Company)
(Dollars in Millions)

	2021	**2022**	**2023**	**2024**	**2025**
AMI	$3.54	$0.57	$0.47	$0.32	$0.22

Q. WHAT IS INCLUDED IN THE O&M IN SUPPORT OF THE CAPITAL DEPLOYMENT COST 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 from an AMR meter to the AMI meter 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 in Section X of my testimony. The training O&M costs include approximately $2 million in costs in 2020 and 2021 that are part of the training plan to prepare the Company's employees and contractors for the AMI meters and data management systems that are being deployed to support AMI. The communication costs include approximately $2 million in costs in 2020 and 2021 for the development and delivery of internal communications in support of the change management plan necessary to communicate the upcoming changes due to AMI. These activities will primarily take place prior to the Company starting the mass deployment of AMI meters in order to prepare the Company's employees and contractors for the changes associated with the AMI project.

F. Distribution Contingency for AMI

Q. DOES DISTRIBUTION'S AMI CAPITAL FORECAST INCLUDE CONTINGENCY AMOUNTS?

A. Distribution's capital forecast for 2020 to 2025 does not include contingency amounts. This is due to the fact that since the execution of the Meter Contract in September 2019 and the limited deployment of AMI meters to support IVVO, Public Service has more certainty surrounding its remaining forecast for AMI.

Q. HOW DID THE EXECUTION OF THE METER CONTRACT PROVIDE THE COMPANY WITH MORE CERTAINTY AS TO FUTURE AMI COSTS?

A. The Meter Contract dictates much of Distribution's costs for AMI meters and installation. More specifically, the Meter Contract costs comprise approximately 87 percent of the Distribution's total AMI costs from 2020 to 2025.

Q. HOW DID THE DEPLOYMENT OF METERS IN SUPPORT OF IVVO PROVIDE THE COMPANY WITH GREATER CERTAINTY AS TO FUTURE AMI COSTS?

A. Through the deployment of 13,000 AMI meters in 2019, the Company has been able to apply lessons learned regarding the installation of AMI meters, i.e., the percentage of meter installations that require fixes to existing wiring or that had access issues. Based on these percentages and associated costs, Public Service was better able to budget for future installations such that it was able to eliminate the contingency amounts for future years.

Q. DID PUBLIC SERVICE'S PREVIOUS CAPITAL FORECASTS INCLUDE CONTINGENCY AMOUNTS?

A. Yes. The Company's previous cost estimates included contingency amounts but much of this contingency was utilized to execute the Meter Contract. As discussed above, the AMI meters selected by the Company have DI capabilities and associated required hardware that were not contemplated when the initial AMI budget was developed which resulted in the need to utilize the contingency.

G. <u>Comparison of Costs to AGIS CPCN Settlement</u>

Q. HOW DO THE CAPITAL COSTS THAT YOU DISCUSSED COMPARE TO THE BUDGET PRESENTED IN THE AGIS CPCN SETTLEMENT?

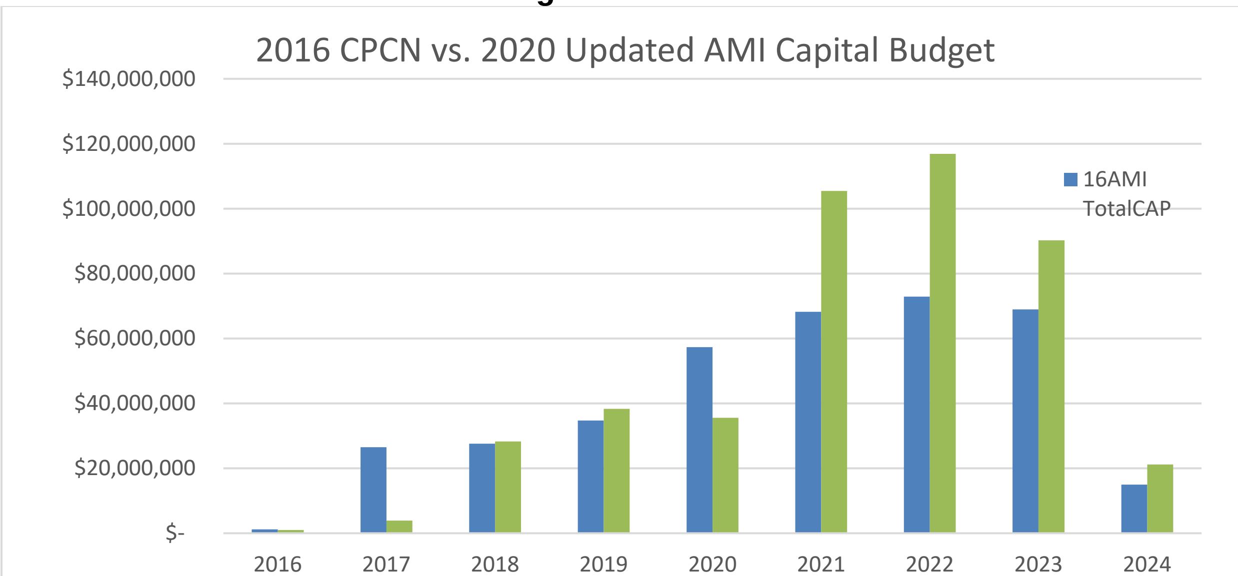
A. Figure CSN-D-4 below shows the forecasted AMI capital costs from the 2016 AGIS CPCN Settlement as compared to the updated 2020 budget utilized in this proceeding. In order to provide a fair comparison of these budgets, the capital budget below includes both internal and contract labor and reflects the capital budgets for both Distribution and Business Systems. This is consistent with how the budget for AMI was presented in the AGIS CPCN Proceeding. The estimated capital costs for AMI from the AGIS CPCN Proceeding was $372 million, including contingency.

The current total capital costs for both Distribution and Business Systems for AMI is $440.8 million, including contingency. The overall capital cost estimate has increased since the AGIS CPCN Settlement primarily due to additional investments by Business Systems in the AMI head-end software and interface assets that are attributed solely to Public Service but that will be utilized by Public

Service as well as other Xcel Energy operating companies. Once Public Service is reimbursed by the other Xcel Energy operating companies through a shared asset credit for these investments, the Company expects the capital costs necessary for Public Service AMI meter deployment to be within the $372 million approved as part of the AGIS CPCN Settlement. As explained by Company witness Ms. Wold, the capital cost related to the AMI head-end and interfaces asset are booked against the Public Service owned asset and Public Service will receive a shared asset credit from the other Xcel Energy operating companies for this shared expense. This shared asset credit is based on the number of AMI meters deployed in each jurisdiction and currently is allocated between Public Service and NSPM (based on the number of AMI meters that have already been deployed in these jurisdictions). This shared asset credit will be reflected in future revenue requirements and is updated as AMI meters are deployed in all jurisdictions. Another reason for the difference between the AGIS CPCN Settlement and the current AMI budget is the fact that the additional costs to activate the HAN capabilities were not included in the AGIS CPCN Settlement. As discussed in greater detail above, the additional approximately $4 million in HAN costs were approved separately in Proceeding 18A-0194E.

In addition to these differences, there have also been shifts in the timing of Public Service's AMI capital investments since the AGIS Settlement Agreement as shown in Figure CSN-D-4.

Figure CSN-D-4



This original schedule for the meter roll-out was scheduled to begin in 2020 and continue through 2024. With the meter roll-out now being delayed until 2021, with the largest portion of AMI meters being installed in 2022 and 2023, there is a corresponding shift in the capital spending to these years. In contrast the budget in the AGIS CPCN Proceeding called for the majority of the AMI meters to be deployed between 2020 to 2023. Table CSN-D-11 below shows the difference between these two AMI meter deployment schedules.

Table CSN-D-11
Amended CPCN AMI Meter Roll-out Schedule

Year	2016 CPCN AMI Meter Roll-Out (# meters)	2020 Updated AMI Meter Roll-out (# meters)	Delta (# meters)
2019	13,000	13,000	0
2020	162,000	0	-162,000
2021	395,000	395,000	0
2022	480,000	534,000	54,000
2023	450,000	504,000	54,000
2024	100,000	154,000	54,000

Q. HOW DO THE O&M COSTS THAT YOU DISCUSSED COMPARE TO THE AGIS CPCN SETTLEMENT?

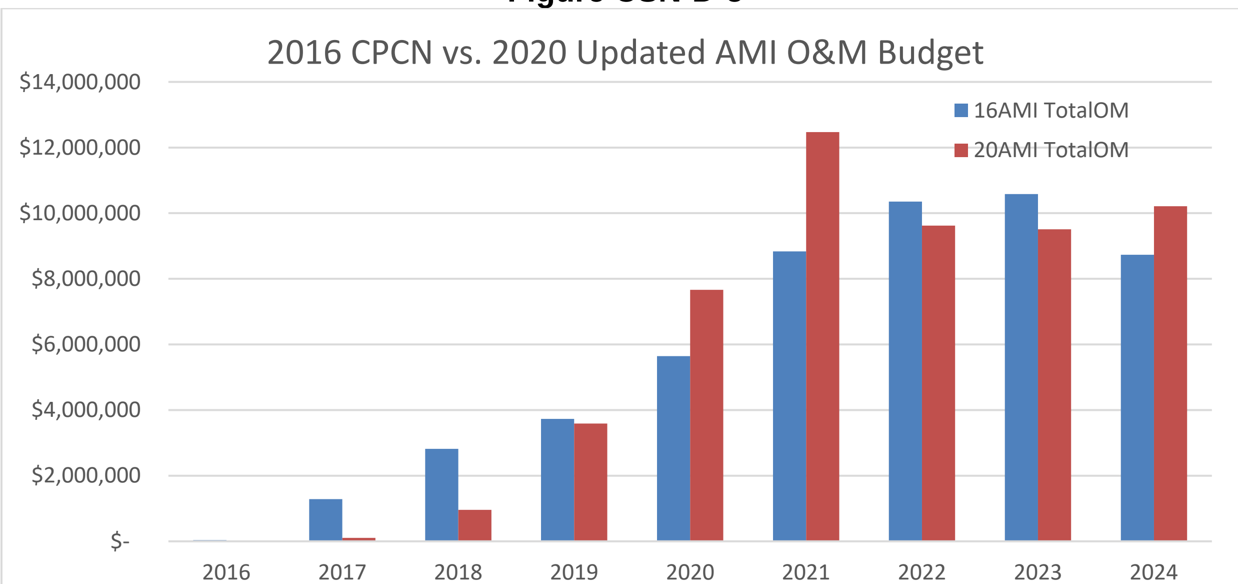
A. Figure CSN-D-5 shows the forecasted AMI O&M costs from the AGIS CPCN Settlement and the updated AMI O&M budget in this proceeding. In order to fairly compare these two budgets, the O&M budget below includes both internal and contract labor, includes an allocated portion from the initiative level costs which reside within "Other"[9] category, and also reflects the AMI O&M budget for both Distribution and Business Systems. This is consistent with the cost estimates provided in the AGIS CPCN Settlement. The estimated O&M costs for AMI from the AGIS CPCN Settlement were $52 million and included costs through the deployment period from 2016-2024, with an updated total O&M costs for AMI of $54 million during this same period.

The largest contributor to the $2.1 million increase in total AMI O&M is the additional AGIS initiative level O&M costs. These are O&M costs associated with running the AGIS initiative which are not budgeted against a specific AGIS project[10] however were allocated to each project to get a fair comparison to the AGIS CPCN Settlement. These costs include: Program Leadership, Program Management Office, and Change Management, Business Readiness, and Testing Leadership, covered in further depth in Section X. As I discuss in Section X, a robust program structure is critical for managing a program of this magnitude and

[9] The allocation portion for each project was based on the percentage of the overall capital spend.
[10] The Change Management and Program Management costs were budgeted as part of each AGIS project as part of the AGIS CPCN Proceeding. The Company has since moved these costs to the "Other" category as part of managing them at the initiative level since many of these activities are in support of AGIS in general and not a specific project.

complexity. As the AGIS initiative has progressed, these O&M costs have moved from the individual project level to the initiative level to support the initiative level functions that are described in Section X.

Figure CSN-D-5



Q. IN SUMMARY, WHY ARE THE DISTRIBUTION BUSINESS AREA'S AMI COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. AMI is a fundamental element of the AGIS initiative because it provides a central source of information that interacts with many of the other components of the AGIS 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.

V. ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

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

A. In this portion of my testimony, I provide an overview of the Advanced Distribution Management Software or ADMS project which includes an effort to improve the data quality and asset information that is stored within our GIS system. I will also discuss the current status of ADMS and of our GIS data collection effort. Finally, I discuss Distribution's current capital and O&M forecasts for ADMS and GIS data collection effort.

A. Overview of ADMS

Q. WHAT IS THE ADMS?

A. ADMS is a foundational system that consists of a collection of hardware and software applications designed to monitor and control the entire electric distribution system safely, efficiently, and reliably. ADMS acts as a centralized decision support system that assists the control room, field operating personnel, and engineers with the monitoring, control, and optimization of the electric distribution system. The multiple applications within ADMS will constitute a single system that will enable the optimization of each application by using one operating model and the same power flow measurements and calculations. It will help control room, field operating personnel, and engineers manage the complex interaction of distributed energy resources, outage events, feeder switching operations, and advanced applications such as FLISR and IVVO. ADMS will enable 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.

ADMS was introduced in the CPCN Proceeding but has been implemented by the Company in the normal course of business which means the Company did not seek a CPCN for ADMS. ADMS was also discussed during Public Service's 2019 Electric Rate Case.

Q. WHAT ARE THE PHYSICAL COMPONENTS OF ADMS?

A. ADMS is composed of hardware, software, distribution supervisory control and data acquisition ("SCADA"), and an impedance model, which is an accurate electrical representation of the distribution grid, including substations, core, and advanced applications.

Q. WHAT IS GIS?

A. GIS is a geospatial program that captures and stores the Company's electric grid asset information that is installed in the field. For Public Service, GIS is, in essence, a digital map of the Company's distribution system. GIS data is critical to the ADMS to provide location and specification information for all of the physical assets that make up the distribution system.

Q. DOES PUBLIC SERVICE CURRENTLY HAVE THE ABILITY TO MONITOR AND CONTROL ITS DISTRIBUTION SYSTEM?

A. Yes. As a described in Section II, the Company has some ability to monitor and control its distribution system, however it is mainly limited to substations and the Company has little insight into the flow of power, voltages, and the operation of equipment on the system beyond the substation. Thus, the Company has little insight into the customer experience – the voltage that the customer is receiving, whether the power is out or has been restored, or any abnormality that might be detectable.

Q. PLEASE DESCRIBE IN MORE DETAIL THE CAPABILITIES THE COMPANY CURRENTLY HAS TO MONITOR AND CONTROL THE DISTRIBUTION SYSTEM?

A. Public Service currently monitors the distribution system through the use of a SCADA system—a system for remote monitoring and control of telemetered points from substations and distribution automation devices. In addition, Public Service monitors the grid through customers reporting outages and power quality issues. The Company also currently uses a connectivity model constructed from its GIS system for the OMS. GIS contains the static physical attribute information about all physical assets that make up the electric distribution system. This model enables outage awareness and improves decision-making when dispatching field personnel to restore power. However, the OMS connectivity model is limited to managing the distribution system outside of the substation (feeder-, tap-, and transformer-level grid components) and it does not include the functionality to control and optimize the system.

Q. ARE THERE LIMITATIONS TO THE INFORMATION THE COMPANY'S SCADA SYSTEM PROVIDES?

A. Yes, the Company's SCADA system has been used primarily to provide remote monitoring and control of generation, transmission system, and substations; but similarly, it lacks the ability to model the distribution system outside the substation or manage the complex interaction of distributed energy resources, outage events, feeder switching operations, and advanced applications such as FLISR and IVVO.

Q. HOW WILL ADMS BE AN IMPROVEMENT OVER THE CURRENT SITUATION?

A. ADMS will constitute a single, integrated system that will enable the optimization of each application by using one operating model and the same power flow measurements and calculations. ADMS will also adjust for real-time grid conditions and topology that are impacted by each application. In addition, when DER and sensor measurements are available, ADMS will use the measurements to improve power flow calculation accuracy and display the measurements and results with geospatial accuracy. This data will be available for use by Operations personnel and advanced applications for both human and automated decision-making. This functionality will enable optimization of both manual and automated switching sequences, IVVO and FLISR functionality, improved reaction time to outage events, increased awareness of voltage levels throughout the grid, awareness of the DER impact to power flow on the grid, and validation of grid operations prior to switching.

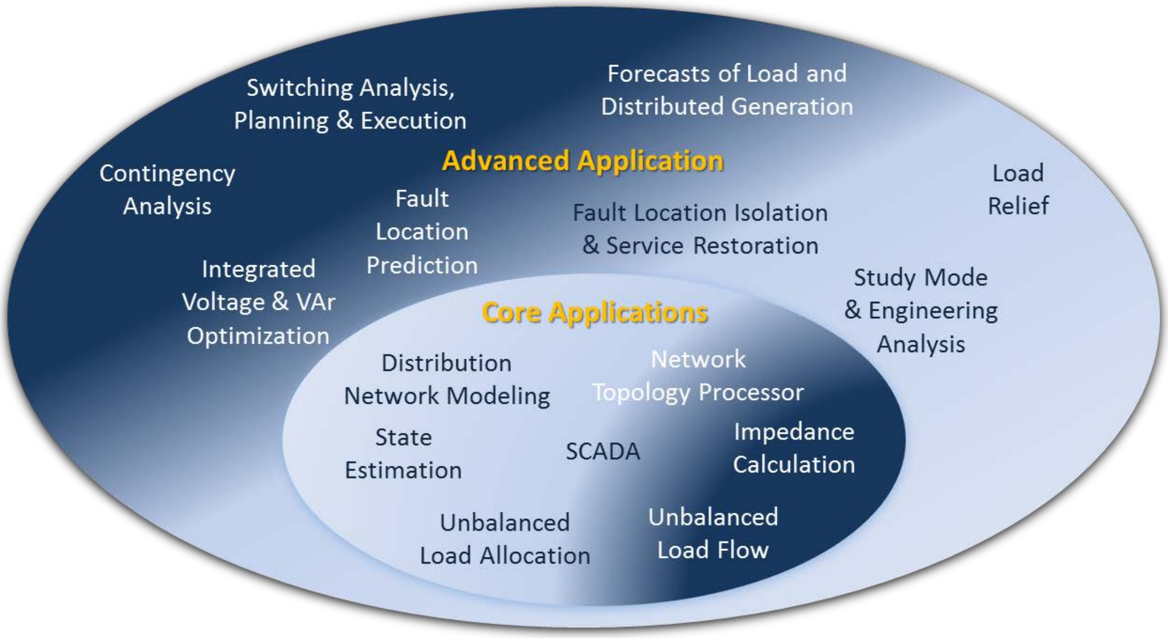
Q. HOW WILL ADMS ACHIEVE THESE IMPROVEMENTS?

A. ADMS will utilize an enhanced distribution grid model that will include substations, feeders, taps, and services, in one user interface, to more accurately represent the entire distribution grid. Because the GIS will provide the nominal geospatial electrical model to ADMS, accuracy of the GIS model will be essential, because this data will improve the model when operating advanced applications like IVVO and FLISR. ADMS will maintain the as-operated electrical model and advanced applications in near real-time. This model will provide the Company with greater visibility into the distribution system and provide information about the system at a more granular level. In particular, Public Service's ADMS will integrate existing SCADA measurements with the enhanced model to provide power flow calculations everywhere on the grid and will accurately adjust power flow calculations with changes in grid topology. This will allow the Company to monitor and control power flow from substations to the edge of the grid. The improved capability over today's systems will enable multiple grid performance objectives to be realized over the entire grid.

Q. PLEASE DESCRIBE THE FUNCTIONS OF ADMS.

A. ADMS has core applications, which make up the foundation of ADMS, as well as advanced applications. Both the core and advanced ADMS applications are listed in Figure CSN-D-6 below. The core applications include distribution network modeling, network topology processor, impedance calculation, unbalanced load allocation, unbalanced load flow, state estimation, and distribution SCADA. These applications provide the basis for running load flow and state estimation on the distribution system providing near real-time calculations of the state of the network including factors such as voltages, currents, real and reactive power, amps, voltage drops, and losses.

Figure CSN-D-6
ADMS Applications



Q. PLEASE DESCRIBE THE ADVANCED APPLICATIONS OF ADMS.

A. The ADMS advanced applications will utilize the core applications and provide additional capability. Public Service now plans to utilize two such advanced applications: IVVO and FLISR. These applications will rely on accurate power flow calculations to determine the power flow at points on the grid where sensor information does not exist. For example, if there are no sensors on a feeder, the Unbalanced Load Flow core application will apply power flow measurements taken at the substation to calculate power flow throughout the feeder.

Although sensors are not a component of ADMS itself, ADMS will utilize sensor and equipment information, located at strategic points on the grid, to continuously improve upon the power flow calculations made by the power flow application. Where sensor data is available, power flow results will be refined and utilized through the ADMS application. For example, State Estimation is an ADMS application that will use measured power flow values from select sensors on a feeder to adjust power flow calculations to more accurately represent the power flow at all points on a feeder. The specific functions of ADMS with respect to IVVO and FLISR are discussed below in Section VI and Section VII respectively of my testimony.

Q. CAN YOU PROVIDE EXAMPLES OF HOW ADMS WILL PROVIDE THE CAPABILITY TO ENABLE MULTIPLE APPLICATIONS AND OBJECTIVES?

A. Yes, the IVVO and FLISR functions (which are discussed in more detail below) will be applied to the same feeders in a given portion of the distribution grid. FLISR will facilitate fault isolation and service restoration activities. IVVO technology will be able to manage voltage and power quality objectives both before and after fault isolation and service restoration activities are carried out by automatic FLISR and manual switching operations. IVVO and FLISR systems can be implemented independently, but the lack of awareness of the performance of the separate standalone systems would reduce the overall effectiveness of each system. By implementing IVVO and FLISR in ADMS, the applications are integrated and coordinated together to realize the full benefits of each application.

Q. WHAT ARE THE POTENTIAL FUTURE USES FOR ADMS?

A. ADMS will provide a dynamic model and real-time power flow information that will facilitate increased penetration and integration of DERs, energy storage, integration of micro-grids, and future customer choice. The need for ADMS arose, at least in part, because of the increase in two-way power flow resulting from the growth of DERs, including renewable resources, on Public Service's distribution system. The visibility enabled by ADMS will provide the Company with information about these resources and their impacts that will be necessary to manage the system. The ADMS platform's ability to monitor, incorporate, and manage the higher penetration levels of DER, storage, and micro-grids, will also enable ADMS to implement actions to limit the potential negative impacts of these technologies on electric customers, such as higher-than-necessary voltage that results from greater penetrations of solar on the distribution feeders and provides the potential to implement new programs to leverage these technologies for additional benefits for customers. As DER penetration levels continue to rise, and as new storage and micro-grid technologies emerge and need to be connected to the grid, other ADMS applications will be necessary to study and manage the behavior of the grid to ensure maintained reliability.

Q. WILL ADMS BE USED FOR PUBLIC SERVICE'S WILDFIRE MITIGATION PROJECT?

A. Yes. The Company plans to integrate the protective devices that are being installed as part of the Wildfire Mitigation Project and plans to enable adaptive protective settings within ADMS to reduce the risk of starting a wildfire during days with high fire risks. This is another use of ADMS, however the Company is not seeking recovery of these costs within this proceeding.

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

Q. WHAT WORK IS DISTRIBUTION UNDERTAKING TO IMPLEMENT THE ADMS AND GIS PROJECT?

A. Distribution is the business area that utilizes ADMS and as such Distribution has worked in partnership with Business Systems to implement ADMS. Distribution was responsible for four components of the ADMS implementation. First, Distribution's partnership with Business Systems included the design, implementation, and testing of ADMS as discussed in further detail by Mr. Reimer. Second, Distribution was responsible for the GIS data collection effort, for which we are collecting and validating data for our Colorado distribution system that is needed to ensure proper ADMS functionality. Third, Distribution was responsible for the implementation of select intelligent field devices to test ADMS and ensure it has the necessary operating information. Finally, Distribution has partnered with Business Systems to build out the system, interfaces, and network to support the deployment of ADMS and the advanced functionality for IVVO and FLISR.

Q. PLEASE DESCRIBE THE WORK THAT DISTRIBUTION HAS ALREADY COMPLETED TO IMPLEMENT ADMS.

A. The Company is deploying the ADMS software by executing the following phases of the project: requirements, design, build, test, and deploy. The requirements and detailed design for the implementation of ADMS which began in 2016 included definition of the business requirements and functionality of the ADMS software, high-level architecture diagrams, and detailed project design necessary to build and configure the ADMS software.

The implementation or build phase of ADMS began in 2017 which as described above is comprised of hardware, software, distribution SCADA, and an impedance model. Initial testing and development of the ADMS software began in 2018 and is being deployed in two phases. The testing required prior to deployment of ADMS includes:

- *Factory Acceptance Testing* –Testing performed by the ADMS software vendor to ensure the software performs according to the requirements and design.
- *Site Acceptance Testing* – Testing performed to ensure all ADMS functionality works properly as defined in the ADMS business requirements and design.
- *Institute Security Controls* – Scans and implements final security controls for access and identity management, logging, vulnerability scanning, and monitoring.
- *System Performance Testing* – Tests the system under various scenarios (e.g., Storm, Normal, and Emergency) to validate operational readiness within defined parameters.
- *User Acceptance Testing* – Assures the system is functioning per expectations of end users and is ready for go-live.
- *Field Device Verification Testing (Point-to-Point Testing)* – Testing of field device communication with ADMS prior to promotion to the production environment.
- *Substation Point-to-Point Testing* – Testing of substation communication with ADMS prior to promotion to production environment.
- *Disaster Recovery Testing* – Recovery testing at the data center (backup site) of failover capabilities in the event of a catastrophic failure in a primary data center.

The Company has completed all testing activities for ADMS. The first deployment in April 2019 implemented the core functions and enabled operation of the IVVO function. The Company's Grid Management team has been using ADMS since April 2019 and has expanded IVVO and FLISR functionality and benefits to additional areas of the system as describe in more detail in Sections VI and VII.

Q. WHAT WORK REMAINS TO BE COMPLETED IN 2020 TO IMPLEMENT ADMS?

A. The second deployment of ADMS is scheduled to occur in the fourth quarter of 2020 and will implement additional functionality and an expanded network model to enable control center operators to use ADMS to manage the distribution system. The Company has completed all of the activities necessary for the control center operators to begin using ADMS to manage the distribution system this year. However, the control center go-live date has been pushed back to the fourth quarter of 2020 due to precautions the Company has taken to isolate the control center operators from risks related to COVID-19. In preparation for the control center go-live, the Company will conduct final training with operators prior to going live in the fourth quarter of 2020.

The Company is also in the final stages of completing the ADMS integrations with AMI, GEMS, and SMS software components that are part of the IVVO and FLISR deployments as described in more detail by Mr. Reimer.

After go-live date, the Company will continue to expand ADMS functionality by augmenting the FLISR and IVVO functions to additional substations and feeders and will include the expansion of other potential future uses as described above.

C. Distribution's Capital Costs for ADMS and GIS

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE DISTRIBUTION BUSINESS AREA'S ADMS AND GIS CAPITAL COSTS?

A. The primary components of the Distribution Business Area's ADMS and GIS capital forecast are: (1) field audit of distribution pole data and data collection and (2) substation data collection and loading.

Q. WHAT PORTION OF THE CAPITAL COSTS FOR ADMS AND GIS HAVE ALREADY BEEN IN-SERVICED?

A. As previously described, Public Service began implementing ADMS and commenced the GIS data collection effort in 2016. Therefore, a significant portion of the capital costs for these projects have already been placed in service and are currently being recovered in base rates.

Q. WHAT IS THE PROJECTED CAPITAL SPEND FOR ADMS AND GIS FOR THE REMAINING IMPLEMENTATION OF THE PROJECT?

A. The table below provides a breakdown of Distribution's capital expenditures forecast for ADMS and GIS for 2020 through 2025. As discussed above, since Public Service plans to make ADMS operational in the control center in the fourth quarter of 2020, there is no anticipated capital investments for this project beyond 2020.

Table CSN-D-13
ADMS and GIS Distribution - Capital Expenditures
(Total Company)
(Dollars in Millions)

	2020	2021	2022	2023	2024	2025	TOTAL
ADMS and GIS	2.67	0.00	0.00	0.00	0.00	0.00	2.67

Table CSN-D-14
ADMS and GIS Distribution - Capital Additions
(Total Company)
(Dollars in Millions)

	2020	2021	2022	2023	2024	2025	TOTAL
ADMS and GIS	2.77	0.00	0.00	0.00	0.00	0.00	2.77

Q. HOW DID THE DISTRIBUTION BUSINESS AREA DERIVE THE INITIAL CAPITAL BUDGET FOR ADMS AND GIS?

A. The ADMS costs are based on the contracts and pricing the Company has with its vendors that support the data collection process and the internal labor for the employees that support this effort. The contracts and pricing are based on a data collection pilot and subsequent RFP the Company conducted in 2017 to select the vendors that support the Company's data collection process.

In addition, to create a forecast for the GIS collection activity, the Company engaged in scoping activities:

- Conducting a gap analysis to determine what additional information was needed in the Company's GIS data model for ADMS to run successfully.
- Identification of changes required to the GIS data model to support ADMS.

- Identification of data to be captured from other sources (such as substation equipment databases) and how this will be provided to ADMS.

- Assessing the quality of data already held in the GIS and external sources and determination whether additional data cleanup activities are required.

- Identification of data attributes that are to be field verified and updated in the GIS.

Q. CAN YOU PROVIDE SOME HISTORY ON HOW THE COMPANY DEVELOPED THE ADMS SCOPE AND COSTS?

A. Yes. In general, the processes used to develop the ADMS scope and costs were the same for both Distribution and Business Systems. Prior to beginning the sourcing process, in 2013 a cross-functional Xcel Energy team began identifying and visiting other United States utilities that had either implemented, or were in the process of implementing, an ADMS. These site visits provided information that was used in the internal planning process. Based on this benchmarking effort, an RFP was issued in 2014 and an extensive sourcing selection process was utilized to determine the successful vendor—Schneider Electric.

In 2015, the Company initiated a "blue print and design" phase with the selected ADMS vendor and other key business partners to develop extensive business and integration requirements for the project. This effort was used to negotiate key contracts with the vendor. To assist in the negotiation process, the Company hired consulting firm ICG to act as a trusted advisor due to ICG's detailed industry knowledge of ADMS to ensure that contract terms and deliverables were reasonable and appropriate. In 2016, following contract negotiations, the

Company and Schneider Electric began detailed design of the project and completed the design in April of 2017. As part of this effort, detailed budgets were developed and updated in June of 2016. After detailed design, Distribution has supported the implementation and functionality testing of ADMS, which has included testing and commissioning of FLISR and IVVO devices, verifying functionality of load flow and state estimation, and commencement of testing IVVO and FLISR algorithms in support of ADMS.

D. <u>Distribution's O&M Costs for ADMS and GIS</u>

Q. WHAT IS INCLUDED IN DISTRIBUTION'S O&M BUDGET FOR ADMS AND GIS?

A. Table CSN-D-15 provides a breakdown of Distribution's O&M expense forecast for ADMS and GIS for 2021 through 2025.

Table CSN-D-15
ADMS and GIS Distribution – O&M Expenses
(Total Company)
(Dollars in Millions)

	2021	**2022**	**2023**	**2024**	**2025**	**TOTAL**
ADMS and GIS	$0.28	$0.25	$0.29	$0.29	$0.29	$1.40

Q. HOW WAS THE O&M BUDGET FOR ADMS AND GIS DEVELOPED?

A. The primary driver of the Distribution O&M costs in 2021-2025 are the O&M costs incurred by the Grid Management Team (Grid Analysts, Grid Engineers, Grid Analysts Supervisor, and Manager of Grid Management) to provide on-going support of the ADMS applications and system models within ADMS. There are additional O&M costs in 2020 related to the labor costs to build out the data in the

ADMS model. These costs decrease in 2021 once ADMS is fully in service in the fourth quarter of 2020 and the initial data collection and model instantiation in Public Service will be complete.

E. Distribution's Contingency for ADMS

Q. DOES THE ADMS PROJECT FORECAST INCLUDE A CONTINGENCY?

A. No. The Company is in the final stages of its data collection effort for ADMS and the forecasted costs for 2020 do not include any contingency.

Q. WHY ARE THE DISTRIBUTION BUSINESS AREA'S GIS DATA COLLECTION COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. ADMS is not only a foundational tool, it is a critical part—the "engine"—of the overall package of tools necessary to deliver reliable energy efficiency measures and to enable the integration of increasing quantities of DERs without compromising reliability and power quality. Of the various data elements required to support the ADMS, GIS is the most critical data source. For ADMS to perform its calculations and provide accurate results, the GIS model had to be enhanced. These calculations will drive the operation of IVVO and FLISR, and the core capabilities within ADMS. These are reasonable and necessary expenses to enable the ADMS capabilities, which in turn provide the customer benefits. Further, the Company underwent an extensive process to select an ADMS vendor that will be able to deliver the overall business requirements that are necessary to operate a modern electric distribution grid. Finally, the initial budget ADMS were developed using the Company's thorough and extensive process in which information was collected from other utilities, industry experts, consultants, and a rigorous sourcing process.

VI. INTEGRATED VOLT-VAR OPTIMIZATION

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

A. In this section of my testimony, I provide an overview of IVVO and discuss the progress that Public Service has made in the development and implementation of IVVO since the project was approved as part of the AGIS CPCN Settlement. I then discuss the five-year deployment plan for IVVO that began late 2017 and the work that is remaining to implement IVVO. Finally, I discuss Distribution's capital and O&M forecasts for IVVO.

A. Overview of IVVO

Q. WHAT IS THE IVVO PROJECT?

A. IVVO is an integrated system that includes the advanced application within ADMS, a communication network, the AMI meters and head-end system and the deployment of automated field devices. Through IVVO, Public Service can more efficiently and accurately maintain proper voltage levels throughout the electric distribution system, thereby reducing energy usage without requiring customer usage changes. IVVO automates and optimizes the operation of the distribution voltage regulating devices located on distribution feeders.

Q. WHERE IS PUBLIC SERVICE DEPLOYING IVVO?

A. The Company is deploying IVVO in the Denver metropolitan area across approximately 60 percent of the Company's feeders which serve approximately 67 percent of Public Service's electric customers.

Q. WHAT FIELD DEVICES ARE INSTALLED ON THE DISTRIBUTION SYSTEM TO SUPPORT IVVO?

A. There will be four principal utility equipment components of IVVO:

- Capacitors;
- Secondary static VAr compensators ("SVCs");
- Voltage sensing devices; and
- Load Tap Changers ("LTCs").

Q. WHAT ARE CAPACITORS AND WHY ARE THEY NEEDED?

A. Electric loads like motors require two types of power to operate: active and reactive power. Distribution line capacitors provide local VAr support or reactive power. By doing so, they help to limit both voltage drop and line losses across the distribution system. Figure CSN-D-7 is a photo of a typical capacitor located on a distribution feeder.

FIGURE CSN-D-7

Q. WHAT ARE SVCS AND WHY ARE THEY NEEDED?

A. The SVCs are electronic secondary capacitors that provide fast, variable voltage support to help stabilize and regulate the voltage. Each device is able to act in less than a cycle (a cycle is defined as 1/60 of a second since the United States AC frequency is 60 Hz), as opposed to a traditional utility capacitor device that operates on a 60 to 90 second time delay. These devices provide dynamic voltage response for load and are located closer to customers - or nearer the edge of the grid - than the Company's existing capacitors. The devices' capabilities enhance the system's ability to respond to the variability of renewable DERs such as solar facilities and other intermittent distributed resources. In the event that IVVO function is limited by localized low voltage, SVCs are a tool that can readily be employed to improve IVVO performance, and thus its benefits. Figure CSN-D-8 is a photo of a typical SVC located on a distribution feeder.

FIGURE CSN-D-8

Q. WHAT IS THE FUNCTION OF THE VOLTAGE SENSING DEVICES?

A. IVVO requires end-of-line voltage sensing to monitor the voltage and ensure it is compliant with ANSI Standard C84.1.[11] The Company is using the 13,000 AMI meters installed in 2019 and intends to use the newly installed AMI meters as

11 ANSI C84.1 establishes the nominal voltage ratings and operating tolerances for the 60 Hertz electric power systems.

"bellwether" sensing devices to provide near real-time voltage sensing. When located at the edge of system (i.e., at the customer premise) where voltage is predictably lowest, these sensors will ensure that IVVO does not lower the voltage to the degree that customers would experience voltage below the acceptable standard. The plan is to utilize approximately 10 meters per feeder to provide this data. Public Service will be able to reassign meters as bellwether meters as necessary should load or feeder topology change.

Q. WHAT IS THE FUNCTION OF THE LOAD TAP CHANGERS ("LTC")?

A. This is equipment that is installed on the substation transformer to enable voltage regulation. Substation transformers equipped with LTCs provide voltage regulation by varying the transformer ratio or tap. LTCs typically have 16 taps above and below neutral (33 taps total) and each tap adjusts the transformer turns ratio by 0.375 percent. LTCs are currently monitored and locally controlled based on the local bus voltage. LTCs raise or lower the voltage by tapping up or down based on the settings of the local controller and the demand of the substation transformer. The LTCs themselves will be used, but the controls for some of the legacy units will be upgraded to allow ADMS to control the setpoints. The new LTCs may also require substation Remote Terminal Unit ("RTU") upgrades due to the increased SCADA data demands of new LTC controls and FLISR relays.

Q. PLEASE DESCRIBE IN MORE DETAIL HOW ADMS SUPPORTS THE OPERATION OF IVVO?

A. ADMS operates as a centralized system that monitors inputs from field devices that are installed as part of the IVVO project and other devices that are integrated with

ADMS (such as the FLISR devices). ADMS will take inputs from these devices and will compute the most efficient way to lower the voltage on the feeders by operating the field devices such as opening and closing capacitors and sending new settings to LTCs and SVCs. The lower operating voltage results in energy savings for customers. ADMS makes decisions based on computations across the system. As a centralized system, ADMS will be able to control the distribution devices to work in unison and to dynamically react to changes on system that result from changes such as changes to customer energy usage, DER generation, and outages on the system.

Q. HOW DOES THE FAN SUPPORT THE OPERATION OF IVVO?

A. IVVO 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 IVVO field devices (and other field devices) or be able to remotely monitor and control these devices.

Q. HOW DOES AMI SUPPORT THE OPERATION OF IVVO?

A. AMI meters are used as bellwether meters to measure the voltage at the customer meter to ensure we are delivering an acceptable voltage to customers and to allow for opportunities for further voltage reduction and energy savings. For IVVO to be successfully and safely operated, end-of-line voltage readings are necessary at approximately 10 locations near the end of each feeder; without AMI, this data would need to be gathered in other ways. The AMI head-end system which is discussed in more detail in the Direct Testimony of Mr. Reimer is integrated with

ADMS to allow for the AMI meter data to be provided to ADMS once it is transmitted over the FAN.

Q. HOW DOES IVVO BENEFIT CUSTOMERS?

A. The legacy distribution system has the capability to monitor voltages at the substation but does not have the capability to allow the Company to constantly monitor voltage levels throughout its feeders. As a result, the Company must often operate the system at a higher voltage than what would otherwise be required to ensure the appropriate voltage at the end of a long feeder.

The IVVO application allows voltage to be monitored along the entire length of the feeder and at selected end points (rather than only at the substation). This insight enables Public Service to operate its feeders at the lower end of acceptable voltage ranges to achieve a variety of operational benefits including:

- Reduction of energy consumption;
- Reduction of electrical demand;
- Reduction of distribution electrical losses; and
- Increased ability to host DER.

Q. CAN YOU GENERALLY DESCRIBE HOW THE IMPLEMENTATION OF IVVO WILL RESULT IN ENERGY SAVINGS?

A. Customer’s end-use devices are designed to operate over a range of voltages. Historically, the voltage on the distribution system is toward the high end of the range, which causes devices to consume more energy. IVVO when operated in conservation voltage reduction (“CVR”) mode will allow the Company to lower the voltage on the feeder while still keeping it within acceptable limits. This lowered operating voltage results in small energy savings for most customers on a feeder.

Q. ARE THERE OTHER BENEFITS ASSOCIATED WITH OPERATING ELECTRICAL DEVICES AT A LOWER VOLTAGE?

A. Yes. Some motors, such as those found in air conditioners, dryers, refrigerators, and oscillating fans operate more efficiently at a lower voltage (114 to 120 volts). A higher voltage (120 to 126 volts) generates more heat, which makes these motors less efficient.

Q. HOW WILL IVVO REDUCE ELECTRICAL DEMAND?

A. A by-product of reduced energy consumption is the corollary reduction of electric demand. Energy reduction is produced by reduced demand over time; similarly, peak demand reduction occurs at a point in time during the summer peak load.

Q. HOW WILL IVVO REDUCE ELECTRICAL LOSSES ON THE DISTRIBUTION SYSTEM?

A. The IVVO models in ADMS will turn the system's capacitors installed along the distribution circuit on and off in an optimal manner to limit the reactive power flowing on each portion of the distribution system. This improves the efficiency of the system and reduces system losses.

Q. HAS THE COMPANY ESTIMATED THE REDUCTION IN ENERGY CONSUMPTION, DEMAND, AND ELECTRIC LOSSES THAT WILL BE ACHIEVED FROM IVVO?

A. The full scope of the deployment provides for energy savings through IVVO operations on 450 feeders, enabled through work performed from the end of 2017 through 2023. During this period, the Company plans to deploy 884 overhead and 90 pad-mounted capacitor banks, 4350 SVCs, and replace LTC controllers on 121 power transformers. As this IVVO hardware is deployed, the Company is able to begin lowering the LTC setpoint to achieve initial energy savings. Through IVVO, the benefit of energy savings through voltage reduction is planned to ramp up to 335,884 MWh annually in 2023. Concurrently, the Company estimates an additional 9,167 MWh/year in loss reduction through power factor improvement. As a result of energy savings and line loss reductions, the Company also estimates 43.9 MW in demand reduction for 2023. Table CSN-D-16 below provides a breakdown of the projected IVVO benefits by year and includes 2019 actual benefits.

Table CSN-D-16
Projected IVVO Benefits[12]

Benefits	2019	2020	2021	2022	2023
Energy Savings (MWh)	18,100	87,500	172,000	255,000	336,000
Loss Reduction (MWh)	550[13]	2,292	4,583	6,875	9,167
Demand Reduction (MW)	5.97	11.5	22.5	33.4	43.9

[12] Per Section D.1.a.iii of the AGIS CPCN Settlement, IVVO energy savings are recovered annually through the Electric Commodity Adjustment ("ECA") rider
[13] In 2019, the Company did not have the capability to calculate the actual loss reduction and therefore number is an estimate.

Q. WHAT ENERGY SAVINGS HAS THE COMPANY ACHIEVED IN THE AREAS WHERE IVVO HAS BEEN ENABLED?

A. The Company began to enable substations with IVVO functionality within the ADMS in April 2019. Two substations, comprising of six transformer areas serving approximately 53,000 customers, were enabled with IVVO functionality throughout 2019 and the Company saw positive results with the transformers areas consistently achieving over two percent energy saving.[14]

Also during 2019, energy savings of 18,100 MWh were achieved resulting in approximately $973,000 in savings for customers on IVVO enabled feeders. In addition, 5.97 MW of demand reduction was achieved on feeders with IVVO enabled resulting in estimated savings of $585,000. The Company currently does not have the capability to estimate the loss reduction, however is in the process of working with its vendor for a way to calculate the loss reduction within ADMS.

Through the first five months of 2020, the Company has achieved energy savings of 20,600 MWh. The rate of energy savings accrual is expected to increase dramatically as more areas are enabled with IVVO. Two additional transformer areas were enabled in the first five months of 2020, with another two expected in June and July.

[14] The estimated savings as part of the CPCN filing were estimated to be 1.9 percent in 2020.

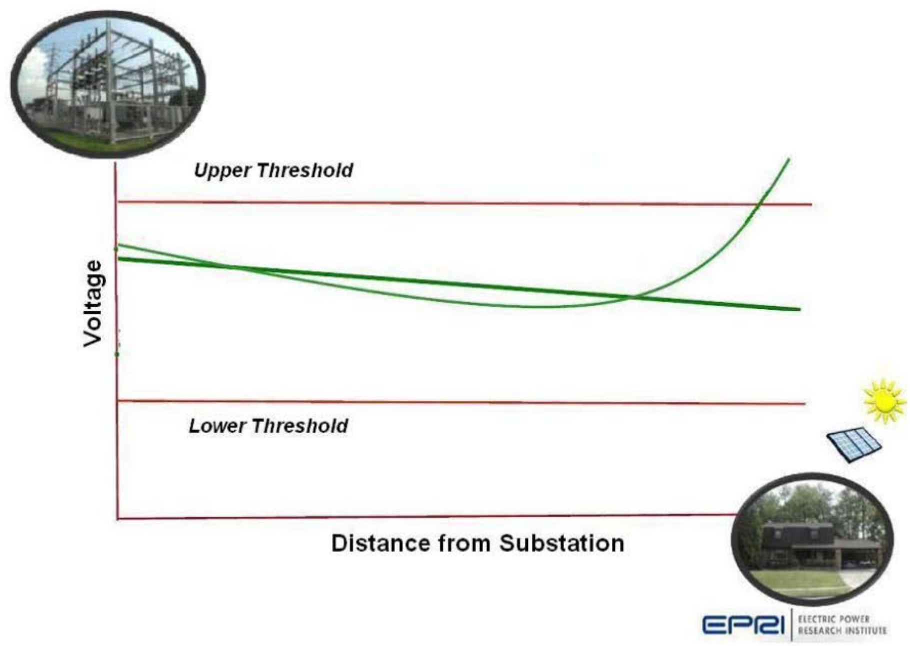
Q. HOW DO THE ACTUAL ENERGY SAVINGS BENEFITS COMPARE TO THE COMPANY'S ESTIMATES?

A. For 2019, customer energy savings were lower than expected. This does not indicate that IVVO is less effective than expected but is reflective of the complexity and the number the steps required to enable IVVO operation which I discuss further later. On average, areas running IVVO saw increased energy reduction when compared to initial estimates; however, the application was not enabled at a large enough area to achieve the forecasted benefits. Public Service anticipates that as IVVO is enabled across a larger area, that the energy savings achieved from IVVO will be in line with the Company's estimates. In addition, as the Company enhances it processes and expertise with enabling IVVO, the Company expects improvements with the timing to complete all of the steps required to enable IVVO.

Q. HOW WILL IVVO INCREASE THE SYSTEM'S ABILITY TO HOST DER?

A. As penetration of DER grows, the Company will need to manage the DER's influence on voltage through distribution system voltage control. Traditionally, with one-way flows on a feeder, the voltage control objective was to raise voltage at times of heavy load to manage voltage within the acceptable range. As shown in Figure CSN-D-9 below, DER which injects power into the system, such as solar generation, increases the voltage on the grid edge, which will be most noticeable during times of lower energy use. By increasing the voltage at the end of the feeder, such DERs can cause over-voltage issues impacting both the DER and other customers. By lowering the voltage and reducing potential over-voltage impacts from solar DERs, IVVO will support the ability for additional solar to be hosted on the system.

FIGURE CSN-D-9



Q. WILL THE ENERGY SAVINGS FROM IVVO LEAD TO OTHER BENEFITS?

A. Yes. There will be environmental benefits associated with the increased energy efficiency. Improved energy efficiency can result in reduced demand for electric generation and thus a reduction in carbon emissions caused by certain types of generation. The reduction in carbon emissions, in turn, will provide environmental and societal benefits.

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

Q. WHAT WORK HAS BEEN COMPLETED TO DATE TO IMPLEMENT IVVO?

A. Implementation of IVVO is on a five-year deployment schedule that began with the first IVVO device being installed in 2018. Distribution will be installing additional field devices and enabling IVVO in ADMS on additional substation transformer areas through 2022 with potential for some carry-over into 2023. From 2018 through the end of May 2020, the Company has installed 347 capacitors, 2,267 SVCs, and completed upgrades of 42 LTCs. Table CSN-D-17 provides a breakdown of the IVVO field installations by year with 2018 and 2019 representing actual installations and 2020-2023 representing forecasted installations.

Table CSN-D-17
IVVO Device Installations

	2018	2019	2020	2021	2022	2023	Total
Capacitors	142	74	200	215	193	150	974
SVCs	453	947	1,322	1,100	528	0	4,350
LTCs	6	20	32	31	32	0	121

The Company has also been working to enable substations with IVVO functionality. IVVO is enabled one transformer area at a time, with each transformer generally consisting of three or four feeders. The Company began continuous IVVO operation on the Englewood Substation Transformer #1 in April 2019, with five more transformer areas (Englewood and Greenwood substations) subsequently enabled through October 2019. In addition, the Company lowers the LTC setpoint or voltage at each substation transformer areas when the LTC upgrades are complete and areas that we have capacitors fully deployed, and where there is confidence in the local voltage support. This also results in a lower voltage and energy savings for customers prior to the IVVO functionality being deployed for each substation transformer area.

Q. PLEASE DETAIL THE STEPS REQUIRED TO ENABLE IVVO FOR EACH SUBSTATION TRANSFORMER AREA.

A. Enabling IVVO in ADMS requires several steps. This includes:

- *Field device installation:* Installation of capacitors and SVCS on the distribution feeders which can be installed on overhead poles or on pad-mounts for underground portions of our system. LTC upgrades at substations which may also require substation remote terminal unit ("RTUs") upgrades due to the increased SCADA requirements.

- *Enabling Communication Through FAN:* Installation of the network interface card within each of the field devices and the necessary FAN devices to enable communication from the field devices to the Company's data servers.

- *Integrating the devices with ADMS:* Once the field devices are communicating to our data servers, the devices can be integrated with ADMS by configuring the communication and device settings within ADMS.

- *Point-to-Point testing:* Once the device is integrated with ADMS, point-to-point testing is performed to verify the device is functioning correctly and it configured correctly in the field and within ADMS.

- *Testing within ADMS:* Finally, before enabling IVVO functionality, final testing is performed in ADMS to verify all of the devices are configured correctly and respond correctly to ADMS commands such as the opening and closing of capacitors.

Q. IS THE WORK THAT HAS CURRENTLY BEEN COMPLETED BY THE COMPANY CONSISTENT WITH THE SCHEDULE PROVIDED DURING THE AGIS CPCN PROCEEDING?

A. As discussed in the previous updates provided as part of the Company's annual and forecast reports in the AGIS CPCN Proceeding, there have been delays with IVVO capacitor deployment due to concern regarding the failure mode of the power line sensors used. The Company identified the problem and worked with the manufacturer to resolve the issue. In the interim, the Company resumed capacitor installations in 2019 and will be retro-fitting the existing capacitor installations starting in the third quarter of 2020 with the improvements the manufacture made to the power line sensors. The Company's forecasted deployment schedule includes the capacitors that were not installed in 2019 due to the delays associated with the manufacture issue of the power line sensors.

Q. WHAT WORK WILL BE COMPLETED BY DISTRIBUTION IN 2020 IN SUPPORT OF IVVO?

A. In 2020, Public Service intends to incorporate reporting from the bellwether AMI meters that were installed in 2019 into ADMS. This reporting will help manage voltage along distribution feeders. In addition, the Company plans to enable 121 feeders in ADMS, lower 30 LTC setpoints, and enable IVVO operation on 34 transformer areas serving approximately 327,000 customers before the end of 2020. Through the end of May 2020, the Company has enabled IVVO on eight substation transformers areas serving approximately 80,000 customers.

Q. PLEASE DESCRIBE THE WORK THAT DISTRIBUTION WILL BE DOING BEYOND 2020 TO IMPLEMENT IVVO?

A. The IVVO deployment and implementation will continue through 2022 with potential for some carry-over into 2023 as the remaining devices are installed and the application is enabled at all planned areas. The integration of additional AMI meters will be enabled over time as full deployment of AMI continues as well.

C. Distribution's Capital Costs for IVVO

Q. WAS THE DISTRIBUTION BUSINESS AREA PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECAST FOR IVVO?

A. Yes. Therefore, I describe the forecast development process for IVVO in detail. After the Company identified IVVO as an advanced application to be included in its AGIS initiative, the Distribution Business Area developed its IVVO forecast by using data from actual installations of comparable devices, as well as pricing details from vendor pricing and pilot projects. The Company has refined its forecast based on actual costs of field device installations and the associated costs to enable IVVO functionality. Some aspects of IVVO implementation, including a software application and ADMS integration, are discussed and supported by Company witness Mr. Reimer.

Q. WHAT IS THE PROJECTED CAPITAL SPEND FOR IVVO OVER THE LIFE OF THE PROJECT?

A. Tables CSN-D-18 and CSN-D-19 below provide a breakdown of Distribution's capital expenditures and capital additions forecast for IVVO for 2020 through 2025.

Table CSN-D-18
IVVO Distribution - Capital Expenditures
(Total Company)
(Dollars in Millions)

	2020	2021	2022	2023	2024	2025	Total
IVVO	24.39	24.68	22.94	8.00	1.70	0.00	81.71

Table CSN-D-19
IVVO Distribution - Capital Additions
(Total Company)
(Dollars in Millions)

	2020	2021	2022	2023	2024	2025	Total
IVVO	27.57	24.98	22.87	8.05	1.75	0.0	85.22

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE IVVO CAPITAL FORECAST FOR ADVANCED APPLICATIONS?

A. The primary components of the IVVO capital investments, shown in the tables above, include: (1) device costs, and (2) installation costs, which include project management, labor, and device operations.

Q. HOW DID THE DISTRIBUTION BUSINESS AREA DERIVE THE CAPITAL FORECAST FOR THE IVVO DEVICE COSTS?

A. The Company was able to use actual costs to develop the capital forecast for the IVVO devices. Previous construction projects across Xcel Energy provided the basis for primary capacitor bank costs. The substation engineering group compiled estimate summaries for several different sites, and those were averaged to provide estimated substation costs. Finally, the Company piloted a project testing SVC device from Varentec, Inc. beginning in 2013. Cost estimates provided from Varentec and actual costs during that pilot were used to estimate costs for that component. As I noted above, the Company has refined its forecast based on actual costs of field device installations.

Q. HOW DID THE COMPANY GO ABOUT SELECTING VARENTEC AS THE VENDOR FOR SVCS?

A. The Company completed an RFP process and selected Varentec as its supplier of SVCs in 2018. The Company evaluated three different vendors based on a variety of factors including cost per unit, number of devices deployed across different utilities, support capabilities, and technical capabilities, ultimately selecting Varentec's Edge of Network Grid Optimization ("ENGO") unit as the best amongst these factors.

Q. HOW DID THE COMPANY SELECT THE VENDORS FOR THE OTHER IVVO DEVICES?

A. Primary capacitors and LTC controllers are apart of the Company's standard equipment, and we were able to use our existing equipment standards to support this deployment. The equipment selected for our standards undergoes periodic review, using the RFP process when appropriate.

Q. HOW DID THE DISTRIBUTION BUSINESS AREA DERIVE THE CAPITAL FORECAST FOR IVVO INSTALLATION COSTS?

A. Many of the devices involved in the IVVO deployment are not new to the Company. As such, the Company was able to use actual costs to develop the forecasts to implement the IVVO solution. With respect to the new SVC devices, Public Service had already engaged in a limited pilot installation of these devices on select distribution feeders, as discussed above; therefore, the Company was able to use actual costs for these devices as well. The Company is primarily using contract labor for the installation of IVVO devices. The forecast for labor costs for device installation were developed using contractor wage scales.

D. Distribution's O&M Costs for IVVO

Q. WHAT IS DISTRIBUTION'S O&M COSTS ASSOCIATED WITH IMPLEMENTING IVVO?

A. The O&M costs include support of capital deployment, asset and device support, minor device replacement, and training. Table CSN-D-20 provides a breakdown of Distribution's O&M expense forecast for IVVO for 2021 through 2025.

Table CSN-D-20
IVVO Distribution – O&M Expenses
(Total Company)
(Dollars in Millions)

	2021	**2022**	**2023**	**2024**	**2025**	**TOTAL**
IVVO	$0.65	$0.39	$0.00	$0.00	$0.00	$1.04

Q. WHAT IS INCLUDED IN THE O&M IN SUPPORT OF THE CAPITAL DEPLOYMENT COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category includes expenses related to equipment installations that are appropriately deemed O&M. One example is certain switching activities (operations) are necessary to safely install new equipment. The Company used actual, average installation costs to forecast these costs.

Q. WHAT IS INCLUDED IN THE ONGOING ASSET AND DEVICE SUPPORT COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category includes labor and repairs to maintain assets in good working order. The Company estimated these costs as a percentage of the number of installed IVVO assets.

Q. WHAT IS INCLUDED IN THE DEVICE REPLACEMENT COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category includes material and labor to replace assets (components which are not property units) in good working order. The Company estimated these costs as a percentage of installed IVVO assets.

Q. WHAT IS INCLUDED IN THE ON-GOING COMMUNICATIONS NETWORK COST CATEGORY AND HOW WERE THESE COSTS DETERMINED?

A. This category labor and incidental material to maintain communications link to IVVO assets. The Company estimated these costs as a percentage of the installed IVVO assets.

Q. WHAT IS INCLUDED IN THE TRAINING COST CATEGORY AND HOW WERE THESE COSTS ESTIMATED?

A. This category includes training costs for the IVVO project. The Company estimated these costs based on number of employees, the time to train them, and wage scales.

E. Distribution's Contingency for IVVO

Q. DOES DISTRIBUTION'S IVVO FORECASTS INCLUDE ANY REMAINING CAPITAL CONTINGENCY?

A. Distribution's IVVO budget forecast for the period 2020-2025 includes capital contingency amounts of approximately eight percent. This amount contingency is adequate because the cost projections for devices and installation were developed based on historical costs and thus the Company has the expertise to accurately estimate the quantity of equipment and cost of installation of the IVVO devices.

Q. HAS THIS CONTINGENCY AMOUNT BEEN UPDATED SINCE THE AGIS CPCN WAS APPROVED?

A. Yes. The contingency that was included in the first two years of the deployment plan has been converted to the base budget as part of the on-going deployment of IVVO devices.

F. Comparison of Costs to AGIS CPCN Settlement

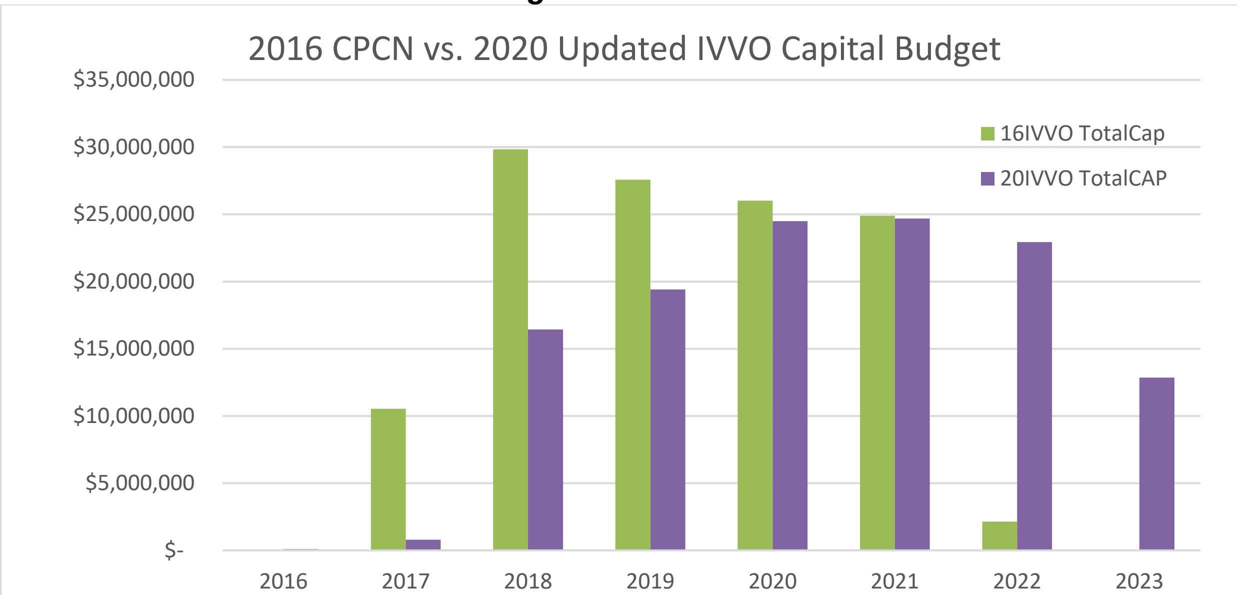
Q. HOW DO THE CAPITAL COSTS THAT YOU DISCUSSED FOR IVVO COMPARE TO THE AGIS CPCN SETTLEMENT BUDGET?

A. This comparison is provided in Figure CSN-D-10 below. In order to complete a fair comparison of budgets, the capital budget below includes both internal and contract labor, and also reflects the budget for both Distribution and Business Systems. This is consistent with the cost estimates provided in the AGIS CPCN Proceeding. The estimated capital costs for IVVO from the AGIS CPCN Proceeding were $121 million and the current total capital costs for IVVO are estimated to be $123.4 million. The estimated capital cost has increased slightly because the actual costs of the capacitors installations have been higher than expected, however the Company anticipates that the final capital costs to complete the IVVO project will be within the amount approved as part of the AGIS CPCN Settlement.

As shown in Figure CSN-D-10 there have also been shifts in the timing of Public Service's IVVO investments. As reported in the 2018 and 2019 AGIS CPCN Actuals Reports, the lower than forecasted capital costs for IVVO in 2018 and 2019 is because the initial ramp up period of IVVO equipment deployment was longer than anticipated and the halt to capacitor installations in late 2018 due to a failure mode of power line sensor that the Company identified and worked with the manufacturer to resolve. The Company plans to make up for these delays by installing more devices in 2020, 2021, and 2022. As a result, the capital forecast for 2020-2022 is higher than forecasted amount from the AGIS CPCN Settlement.

In addition, as noted above, based on the complexity and the number the steps required to enable IVVO operation within ADMS, the Business Systems costs and forecast have also shifted to later years (i.e., 2020-2022) from what was originally forecasted as part of the AGIS CPCN Proceeding.

Figure CSN-D-10

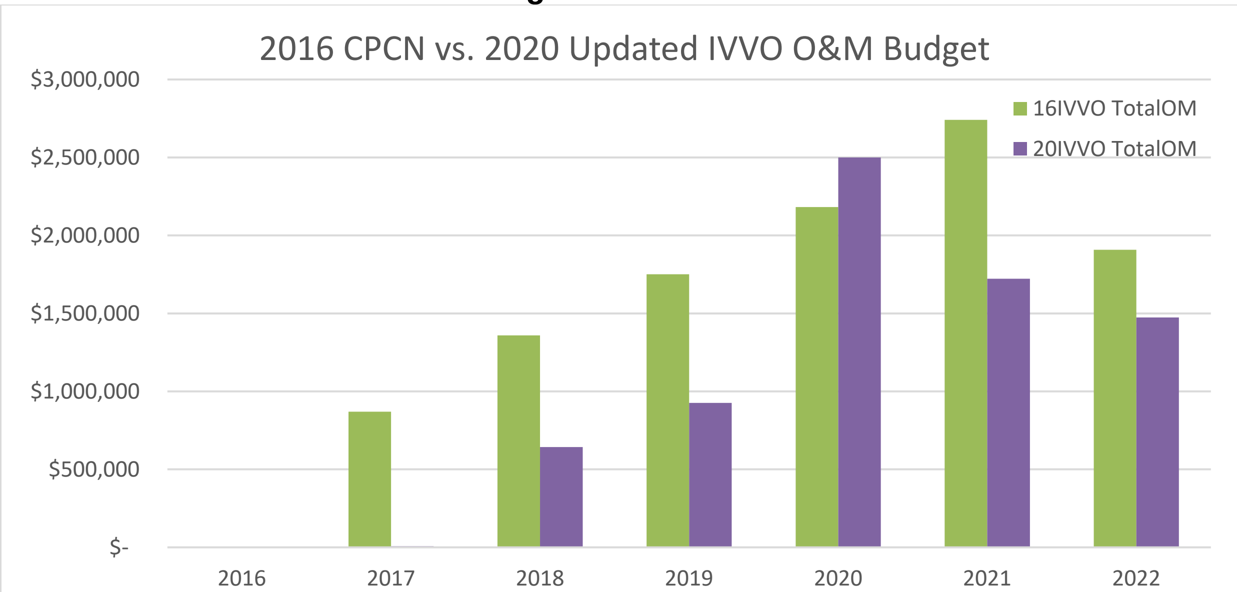


Q. HOW DO THE O&M COSTS THAT YOU DISCUSSED FOR IVVO COMPARE TO THE AGIS CPCN SETTLEMENT BUDGET?

A. This comparison is provided in Figure CSN-D-11 below. In order to fairly compare these two budgets, the O&M budget below includes both internal and contract labor, includes an allocated portion from the initiative level costs which currently reside within the "Other"[15] cost category, and also reflects the budget for both Distribution and Business Systems. This is consistent with how the cost estimates were provided in the AGIS CPCN Settlement. The estimated O&M costs for IVVO from the AGIS CPCN Settlement was $10.8 million for over the deployment period and the current forecast for O&M costs for IVVO is $7.3 million over that same period. The lower than estimated O&M costs has been driven by lower than estimated maintenance costs for IVVO devices installed in the field.

[15] The allocation portion for each project was based on the percentage of the overall capital spend.

Figure CSN-D-11



Q. IN SUMMARY, WHY ARE THE DISTRIBUTION BUSINESS AREA'S IVVO COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. Fundamentally, IVVO is a demand side management ("DSM") tool that reduces energy consumption without requiring behavioral changes from customers. IVVO allows voltage to be monitored along the entire length of the distribution feeder and at selected endpoints (rather than just at the substation). This insight into the voltage levels allows the Company to utilize lower voltages across the entire feeder most of the time. This results in a reduction in electrical losses, reduction in electrical demand, reduction in energy consumption, and an increase in the capacity to host DER. Reductions in energy consumption reduce carbon emissions (caused by certain types of generation) and supports of the Company's strategic vision for serving customers with 100 percent carbon-free electricity by 2050 and 80 percent carbon-free electricity by 2030.

VII. FAULT LOCATION ISOLATION SYSTEM RESTORATION

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 FLP and the benefits associated with these applications. I then discuss the implementation plan for FLISR and the work that has been completed to date. Finally, I discuss Distribution's capital and O&M forecasts for FLISR. FLISR Overview

Q. WHAT ARE FLISR AND FLP?

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").

FLP is a subset application of FLISR that leverages sensor data from field devices to locate a faulted section of a feeder line and reduce patrol times needed to physically locate a failure on the system.

FLISR and FLP were introduced and discussed in the AGIS CPCN filing but has been implemented by the Company in the normal course of business. FLISR and FLP were further discussed in Public Service's 2019 Phase I Electric Rate Case.

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 DO PUBLIC SERVICE'S LEGACY SYSTEMS IDENTIFY AND ISOLATE FAULTS?

A. The Company has SCADA system capability at nearly all of its substations that informs operators of most 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), Public Service must rely on calls from customers to inform the Company of an outage. A key function of an Outage Management System ("OMS") is to figure out which customers are out and where to send our first responders. As customers call to report outages, their service locations are identified in the Company's OMS. Initially, each outage is identified as affecting a single customer. The OMS then correlates additional callers' service locations to our system and determines the most probable area for us to initiate our repair activities. The Control Center Operator then uses aggregated information from all current outages, prioritizes, and dispatches field personnel to start patrolling an area. Prior to ADMS, the Company did not have fault location prediction capabilities, and this could result in field crews patrolling several miles 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 Public Service has been 76 minutes (not storm-normalized). Public Service feeders serve, on average, 1,897 customers. I discuss the expected benefits of FLISR in more detail later.

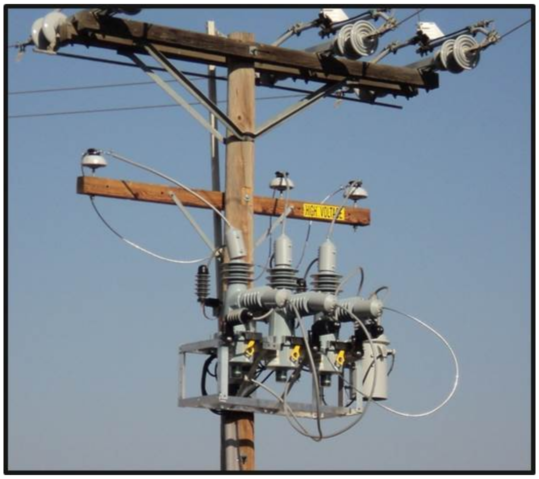
Q. WHAT ARE THE COMPONENTS OF FLISR?

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. The Company 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 employed by the Company 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 the Company 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-D-12 is a picture of a recloser on a distribution pole.

Figure CSN-D-12
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 the Company 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 Public Service 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. The Company hopes to leverage the equipment in the future to detect defective equipment before it fails.

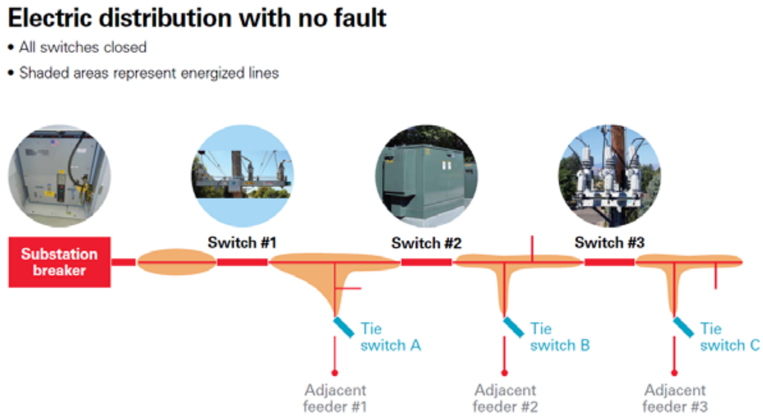
Q. WHAT IS THE FUNCTION OF THE SUBSTATION RELAYS?

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.

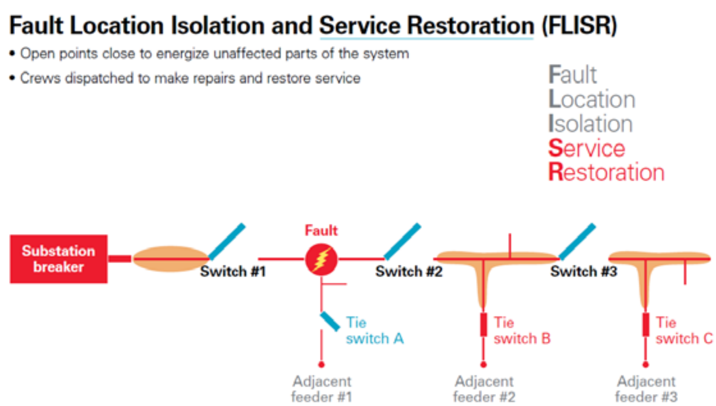
Q. PLEASE DESCRIBE IN MORE DETAIL HOW ADMS SUPPORTS THE OPERATION OF FLISR?

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-D-13 below shows how FLISR isolates that impacted feeder section to restore power to other sections of the line.

Figure CSN-D-13
FLISR Feeder Configuration – Prior to Fault



FLISR Feeder Configuration – Service Restored



Q. HOW DOES THE 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. CAN YOU DESCRIBE IN MORE DETAIL HOW FLISR BENEFITS CUSTOMERS?

A. Yes. Electric power outages and blackouts cost the United States about $44 billion annually, according to a 2018 study by Lawrence Berkeley National Laboratory ("LBNL").[16] 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.[17]

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.

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16 *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.

[17] *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.

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 example, for many of the larger energy requests, such as data centers, electric reliability is typically one of the main considerations emphasized when determining a location as high reliability is 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 Colorado.

Q. HOW DOES THE COMPANY'S RELIABILITY COMPARE WITH THAT OF PEER UTILITIES?

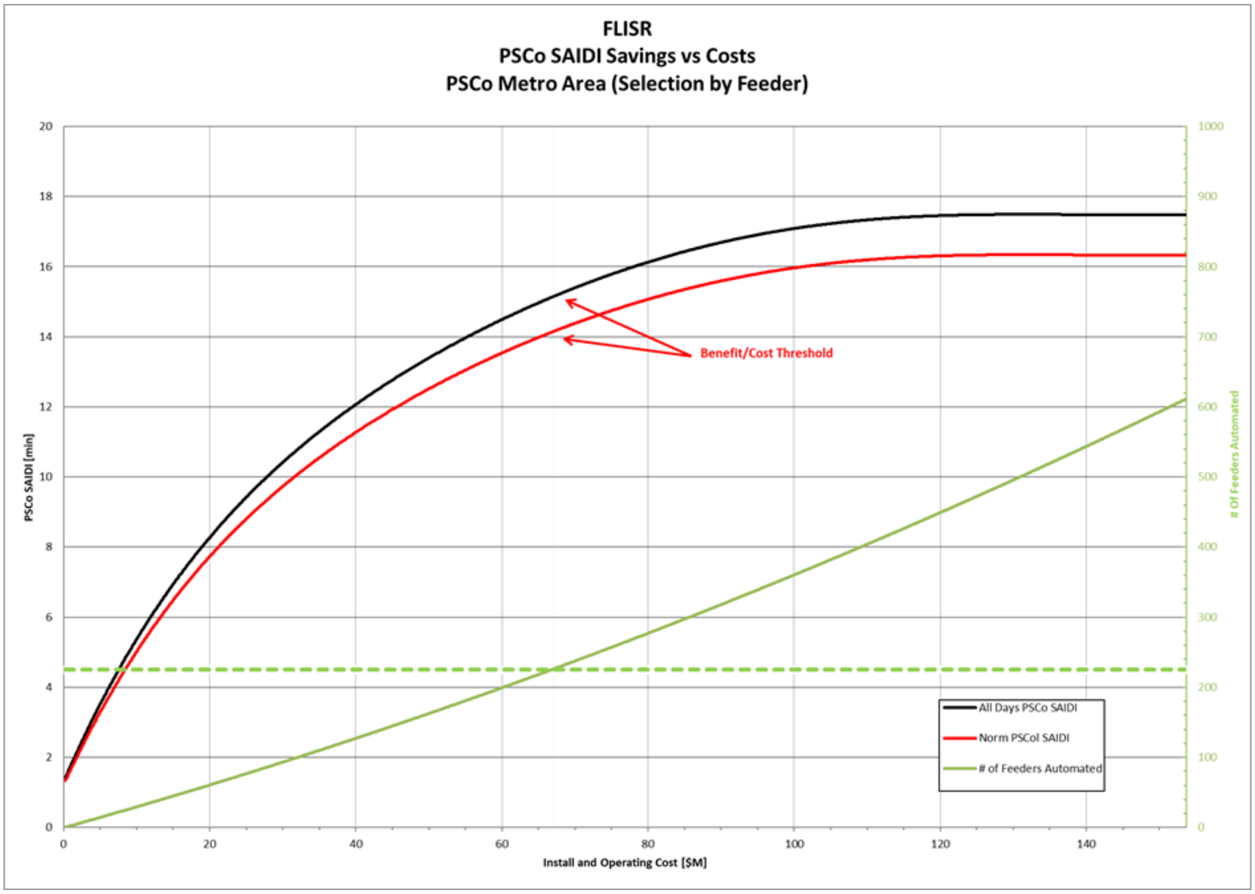
A. Public Service continues to be a leader in terms of reliability performance when compared to our peer utilities. The Company is consistently in the top performance quartile and, on average, customers have electric service more than 99.9 percent of the time. However, as reliability standards increase over-time and as other utilities implement more advanced technologies, the Company anticipates it may not maintain its position amongst its peers if it does not enhance its reliability performance through investments in FLISR.

Q. DOES THE COMPANY HAVE PLANS TO DEPLOY FLISR ON ALL OF ITS DISTRIBUTION FEEDERS?

A. No, the Company's plans to install automated equipment on approximately 205 feeders or approximately 25 percent of the feeders on the Company's distribution system. The Company developed the overall deployment plan for the FLISR project in 2016 based on a cost/benefit analysis summarized in Figure CSN-D-14.

As Figure CSN-D-14 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.

FIGURE CSN-D-14



Q. CAN YOU DESCRIBE IN MORE DETAIL WHY IT MAY NOT BE COST EFFECTIVE TO DEPLOY IT ON ALL FEEDERS?

A. Some of the areas of the Company'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 25 percent of the Company's feeder have not had any mainline outages from 2015-2019 and around 80 percent of the Company's feeders have averaged less than one mainline outage per year from 2015-2019. Whereas the remaining feeders on the Company's distribution system have had a higher number of outages which FLISR can reduce the number of customers impacted by a fault on a system and the time to restore power for customers as I described in more detail previously. In addition, as with all the investments Public Service makes, the Company evaluates the costs and benefits of enhancing the experience for customers and FLISR is one of the most cost-effective ways for improving reliability for customers.

Q. WILL THE COMPANY DEPLOY FLISR TO ONLY THOSE CIRCUITS WITH POOR RELIABILITY PERFORMANCE?

A. No. A FLISR system is formed by creating automated ties with adjacent feeders, which then work together in mutual support. To identify the best candidates for FLISR, engineers analyze areas with reliability challenges and determine an optimal FLISR system to optimize improvement. Within each system there will be diversity of feeder reliability history. Some feeders may even have very high reliability, and thus are especially suited to serve the FLISR system's needs as tie feeders to those feeders with lower reliability performance.

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

Q. WHAT WORK IS THE DISTRIBUTION BUSINESS AREA UNDERTAKING TO IMPLEMENT FLISR AND FLP?

A. The FLISR and FLP devices are on a nine-year deployment schedule that began in 2016. The deployment priority is based on the historical reliability performance of the feeders, starting with the worst performing feeders within the FAN and IVVO footprint area, which is mainly covering the Denver metropolitan area where the highest density of customers exists. 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. There will also be make-ready work that is necessary to complete in order to install these devices, such as reconfiguring the location of a pole to allow 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. WHAT IS THE CURRENT STATUS OF THIS PROJECT?

A. Public Service is taking a multi-step approach to FLISR in Colorado. The first step involves deployment of protective equipment that can be leveraged with local programming to reduce outage exposure for customers. Secondly, 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 outage response teams closer to faults after they occur, thereby reducing outage durations for affected customers. Finally, Control Center staff will take an active role in managing FLISR devices, either remotely operating devices or allowing the ADMS to automatically operate devices so that customer sections can be brought back online within minutes of a fault occurring.

Today, Public Service has deployed approximately 200 new devices in the first stage and those devices have begun to generate benefits for customers. Company is in the final stages of device point to point testing and ADMS enablement with the goal of bringing seven FLISR feeders into the second stage. As the Control Center transitions to utilizing the ADMS later in 2020, feeders will be moved from the second stage to the third stage, with operators first manually operating devices as faults occur on the system (also known as 'Open Loop' FLISR), and ultimately allowing the ADMS to automatically operate devices (also known as 'Closed Loop' FLISR).

Q. WHAT WORK WILL PUBLIC SERVICE BE PERFORMING BETWEEN 2020 TO 2025 TO IMPLEMENT FLISR?

A. Public Service is continuing to deploy FLISR field devices (reclosers, switches, and substation relays) at a relatively steady rate through 2025 with the possibility of rolling deployments into 2026 if necessary. The device installation rate is shown in Table CSN-D-21 below. By the end of 2025, FLISR devices will be installed on approximately 205 feeders, benefiting nearly 390,000 customers. As I described above, the Company currently does not have plans to deploy FLISR on all feeders as some feeders already have extremely high reliability and based on the Company's cost/benefit analysis there was diminishing benefits to customers beyond the proposed funding level for the FLISR project.

Table CSN-D-21
FLISR Field Device Installation

FLISR Field Devices	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Field Devices	29	43	76	38	46	59	64	64	64	109	592
No. of Feeders	10	15	26	14	16	20	22	22	22	38	205

H. Distribution's Capital Costs for FLISR

Q. WAS THE DISTRIBUTION BUSINESS AREA PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECAST FOR FLISR AND FLP?

A. Yes. Therefore, I describe the forecast development process for FLISR and FLP in more detail. After the Company identified FLISR and FLP as advanced applications to be included in the AGIS initiative, Distribution developed its forecast for FLISR and FLP by using data from actual installations of comparable devices, as well as pricing details from vendors and pilot projects. Some aspects of FLISR and FLP implementation, including the integration of the Sensor Management System for Aclara sensors into ADMS and ADMS IT integration are discussed and supported by Company witness Mr. Reimer.

Q. WHAT IS THE PROJECTED CAPITAL SPEND FOR FLISR AND FLP OVER THE LIFE OF THE PROJECT?

A. Tables CSN-D-22 and CSN-D-23 below provides a breakdown of Distribution's capital expenditures and capital additions forecast for FLISR and FLP for 2020 through 2025.

Table CSN-D-22
FLISR and FLP Distribution - Capital Expenditures
(Total Company)
(Dollars in Millions)

	2020	2021	2022	2023	2024	2025	**Total**
FLISR and FLP	5.60	6.19	6.63	7.75	6.67	6.67	39.51

Table CSN-D-23
FLISR and FLP Distribution - Capital Additions
(Total Company)
(Dollars in Millions)

	2020	2021	2022	2023	2024	2025	**Total**
FLISR and FLP	5.16	5.96	6.47	8.05	6.54	6.60	38.78

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 in Tables CSN-D-22 and CSN-D-23 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. The Company 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. The Company had previously piloted FLP sensors from Aclara and actual costs from this work were used to develop forecasts for 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 THE COMPANY 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). The Company started to install FLISR and FLP devices in 2016 and we were able to use historical installation and labor costs to develop the capital cost estimates.

I. <u>Distribution's O&M Costs for FLISR and FLP</u>

Q. WHAT IS DISTRIBUTION'S O&M COSTS ASSOCIATED WITH THE IMPLEMENTATION OF FLISR?

A. 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-D-24 provides a breakdown of Distribution's O&M expense forecast for FLISR and FLP for 2021 through 2025.

Table CSN-D-24
FLISR and FLP Distribution – O&M Expenses
(Total Company)
(Dollars in Millions)

	2021	2022	2023	2024	2025	**Total**
FLISR and FLP	$0.32	$0.58	$0.61	$0.63	$0.64	$3.02

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. The Company 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. The Company 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. The Company 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. The Company 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. The Company 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.

J. Distribution's Contingency of FLISR

Q. DOES DISTRIBUTION'S CAPITAL FORECAST FOR FLISR INCLUDE CONTINGENCY?

A. Distribution's FLISR capital forecast for the period 2020-2025 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 REASONABLE FOR CUSTOMERS TO SUPPORT?

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 our system and target areas that historically have experienced a higher number of outages. Enhancing the reliability of our system will not only improve reliability of our existing customers but can be important for attracting industries that require higher reliability (such as data centers) to Colorado which in turn can bring jobs and economic development to Colorado.

VIII. FIELD AREA NETWORK

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 the progress that Public Service has made in the development and implementation of FAN since approval of the AGIS CPCN Settlement. The implementation of FAN is a joint effort with Business Systems with Business Systems leading this effort. As a result, Mr. Reimer provides a more detailed discussion of FAN and its components and implementation. I discuss the implementation plan for Distribution's portion of FAN. Finally, I provide Distribution's capital and O&M forecasts for FAN.

A. Overview of FAN

Q. WHAT IS THE FAN?

A. The FAN is the wireless communications network that enables connectivity and two-way communications between the existing infrastructure at the Company's substations, the ADMS and AMI software systems, the new AMI meters, and the intelligent field devices associated with advanced applications. The FAN applies to all aspects of AGIS but is designed and built according to the needs of various components, and each has different communication network requirements.

Q. WHAT ARE THE COMPONENTS OF THE FAN?

A. The FAN will consist of two separate wireless technologies: (a) a lower-speed Wireless Smart Utility Network ("WiSUN") mesh network; and (b) a high-speed point-to-multipoint private wireless network to connect the WiSUN mesh network to the WAN.

Q. HAVE THERE BEEN ANY CHANGES TO THE COMPONENTS OF THE FAN SINCE THE AGIS CPCN WAS GRANTED?

A. Yes. Initially, the Company proposed in the AGIS CPCN Proceeding to accomplish the private wireless network by the deployment of the Worldwide Interoperability for Microwave Access ("WiMAX") network. As further discussed by Mr. Reimer, new Federal Communications Commission ("FCC") regulations required the Company to replace all WiMAX supported technology with public cellular data technology as an interim solution to support continued connectivity to the WiSUN network. However, the Company still plans to deploy a private wireless network to connect the WiSUN to the WAN. For the longer term, the Company is currently analyzing the potential for a private LTE solution to support these connections. It is expected that the Company will complete its analysis by the end of 2020. The Direct Testimony of Company witness Mr. Reimer discusses the options that the Company is exploring to replace the WiMaX and the different capabilities and features of each of these options.

Q. HOW WILL THE FAN CONNECT TO THE COMPANY'S EXISTING INFRASTRUCTURE?

A. The FAN will be connected to Public Service's pre-existing Wide Area Network ("WAN"). Public Service's WAN is a communications network that provides an intermediate link in the Company's communication system that provides high-speed, two-way communications capabilities and connectivity in a secure and reliable manner between Public Service's core data centers and its service centers, generating stations, and substations. The connections between FAN and the WAN will be primarily at substations on the distribution system. Company witness Mr. Reimer discusses the connection between the FAN and WAN in greater detail in his Direct Testimony.

Q. WHAT ARE THE COMPONENTS OF THE WISUN NETWORK?

A. The WiSUN (mesh) network will communicate directly with the AMI infrastructure (including the AMI meters) and the field devices used for IVVO and FLISR. The core infrastructure for the WiSUN mesh network will consist of two main device types:

- *Access Points*: device that will link the Company's endpoint devices that are enabled with wireless communication modules with the rest of the Company's communication network. The access points will wirelessly connect directly to backhaul (which is an intermediate link in the communications network) to pass data between the mesh network and the WAN. The access points will be located primarily on distribution poles and other similar structures.

- *Repeaters*: are range extenders that are used to fill in coverage gaps where devices would be otherwise unable to communicate. The mesh network design of WiSUN means that additional nodes on the network provide devices more options to communicate with their access point. Repeaters will be located primarily on distribution poles.

Other devices that will participate in the mesh include AMI meters and DA devices, such as the intelligent FLISR and IVVO field devices, that have built-in mesh radios. The former will be located on customer premises; the latter will be co-located with either pole-mounted or pad-mounted distribution devices.

Q. WHAT ARE THE COMPONENTS OF THE PRIVATE WIRELESS NETWORK (FORMERLY KNOWN AS THE WIMAX)?

A. The private wireless network will provide redundant, reliable, and secure connectivity between the WiSUN network and the Company's WAN. This private network will consist of two main components: (1) base stations; and (2) customer premise equipment ("CPE").[18]

Base stations will serve as the key communication points between the substation WAN and the WiSUN mesh network. At substations there will be a base station with up to three radios that will communicate with the WAN and multi-directionally with CPEs out in the field of operations. Where possible, the base stations at the substations will be mounted on existing poles or structures.

The CPEs will further enable the back-office applications to communicate wirelessly with any device accessible to that access point's connections to the mesh network. CPEs will be mounted on distribution poles in the field of operation. The WiSUN and private wireless network technologies are discussed in more detail by Company witness Mr. Reimer.

18 To provide context, CPE is a common term in the network industry that refers to specific equipment. In the term "CPE", the "customer" refers to Public Service (or a similarly-situated entity using this equipment), which is a customer of the equipment manufacturer. It does not refer to any specific customers of Public Service, or to Public Service's customers generally.

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 the installation of the FAN devices (primarily access points and repeaters) that will be located on distribution poles. Business Systems will be responsible for installation of base stations at the substations. Business Systems will also be responsible for the design of the network systems for private wireless network and WiSUN, the security of these networks, and configuring the software and hardware components of FAN.

Q. HOW WILL THESE FAN DEVICES BE INSTALLED BY DISTRIBUTION?

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 Public Service has underground service, arrangements will be made to mount the devices on street lights or other structures with appropriate height.

Q. PLEASE DESCRIBE THE WORK THAT DISTRIBUTION HAS ALREADY COMPLETED THROUGH THE END OF 2019 IN SUPPORT OF FAN.

A. As discussed by Mr. Reimer, the WISUN portion of the FAN is being implemented in a three-phased approach. The Company 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 the Company 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 2019, the Company completed 119 site surveys.

Also, in 2019, Public Service commenced installation of WiSUN devices as part of Phase III. Due to the fact that the Company shifted out the start of the mass meter deployment from 2020 to 2021, the Company installed fewer WiSUN devices in 2019 than originally planned.

Q. WHAT WORK IS PLANNED FOR 2020 TO 2025 TO IMPLEMENT FAN?

A. Distribution will continue to complete site surveys at a pace of approximately 100 surveys per year through 2024. Installation of WiSUN devices will also continue through 2024 to support AMI deployments. The Company expects to install 135 WiSUN devices in 2020. This schedule is slightly advanced to support IVVO and FLISR requirements as well. Further details regarding the implementation of WiSUN are discussed by Company witness Mr. Reimer.

C. 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. Mr. Reimer discusses Business Systems' FAN costs which is the largest portion of the costs for this project.

Q. WHAT IS THE PROJECTED CAPITAL SPEND FOR FAN OVER THE LIFE OF THE PROJECT?

A. Table CSN-D-25 below provides a breakdown of Distribution's capital expenditures forecast and Table CSN-D-26 depicts capital additions forecast for FAN for 2020 through 2025.

Table CSN-D-25
FAN Distribution - Capital Expenditures
(Total Company)
(Dollars in Millions)

	2020	2021	2022	2023	2024	2025	**Total**
FAN	4.73	5.79	3.18	3.18	2.15	0.0	19.03

Table CSN-D-26
FAN Distribution - Capital Additions
(Total Company)
(Dollars in Millions)

	2020	2021	2022	2023	2024	2025	Total
FAN	5.64	5.89	3.18	3.18	2.15	0.00	20.04

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. Reimer. 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. Our labor estimates are based on our prior experience with installing FAN devices.

D. Distribution's O&M Cost for FAN

Q. WHAT IS THE PROJECTED O&M COSTS FOR FAN OVER THE LIFE OF THE PROJECT?

A. Table CSN-D-27 below provides a breakdown of Distribution's O&M expense forecast for FAN for 2021 through 2025.

Table CSN-D-27
FAN Distribution – O&M Expenses
(Total Company)
(Totals in Millions)

	2021	2022	2023	2024	2025	**Total**
FAN	$0.46	$0.50	$0.52	$0.53	$0.26	$2.97

Q. WHAT ARE THE PRIMARY COMPONENTS OF DISTRIBUTION'S O&M COSTS FOR FAN?

A. The FAN's O&M costs will include 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 Company 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 Company 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.

E. Distribution Contingency for FAN

Q. DOES DISTRIBUTION'S CAPITAL FORECAST FOR FAN INCLUDE CONTINGENCY?

A. No. There is no contingency amount included in Distribution's FAN costs because the contingency amounts for FAN reside in the Business Systems budget as described by Mr. Reimer.

Q. IN SUMMARY, WHY ARE THE DISTRIBUTION BUSINESS AREA'S FAN COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. The FAN provides the ability for all of the AGIS 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 AGIS 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.

IX. ADVANCED PLANNING TOOL AND OTHER CAPITAL

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

A. In this section of my testimony, I describe Distribution's need for the Advanced Planning Tool ("APT") which is software that is being implemented by Business Systems for use by Distribution. As a result, Business Systems will provide information about the costs for the APT. In this section, I will also discuss the substation communication project that is included in the "other" AGIS capital cost category.

A. APT

Q. WHAT IS THE DISTRIBUTION ADVANCED PLANNING TOOL ("APT")?

A. The Distribution APT is a forecasting and planning tool that will enable Public Service to efficiently expand its distribution planning capabilities to incorporate distributed energy resources, enhance its load forecasting capabilities, and better integrate and align with the Company's other planning tools and processes. The Company's distribution planning team will utilize this new capability to study various forecasts and DER adoption scenarios resulting in improved distribution plans. The advanced planning tool is provided by Integral Analytics and is called LoadSeer.

Q. WHAT EVALUATION PROCESS WAS USED TO SELECT THE LOADSEER PRODUCT?

A. The Company took a multi-step approach to evaluating potential future tools. This included information gathering and prescreening, applying evaluation criteria to potential vendors subsequent bid proposals, inviting the top vendors to provide product demonstrations, and external vetting.

In order to further validate the LoadSeer selection determination, the Company also reached out to industry experts and existing LoadSeer utility industry customers to gauge tool experience, understand their use cases and tool and vendor services satisfaction. Based on the aforementioned evaluations, we determined LoadSeer is the appropriate tool for the next phase of the Company's distribution forecasting.

Q. WHY IS THE APT NEEDED?

A. Distribution planning involves analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels, and utilization rates of major system components such as substations and feeders.

Traditionally, load growth rates were developed by feeder, derived from historical data and known inputs. Planners then identified system constraints such as substation or feeder capacity or low voltage. However Public Service's customers are increasingly exercising more choice around their use of energy. Some of these choices, including DER and beneficial electrification such as electric vehicles (EV) make granular load forecasting a much more complex and important undertaking than it was only a few years ago. Utilities, instead of planning just for load, need to analyze the system for future connections that may be load or generation. The Company also needs to view operations and customer tools from our customers' perspectives.

An APT will allow Public Service to plan for its systems differently than before, allowing for improved processes and methodologies utilizing new tools and capabilities. The principle improvements APT will provide to the planning process will be 1) to more accurately forecasts feeder loads and generations, which will enable the electrical modeling tools to more accurately identify performance and system constraints, and 2) to enable our planners to more efficiently study various scenarios for load growth or DER adoption.

Q. WILL THE APT SUPPORT THE HOSTING CAPACITY INFORMATION THAT IS PUBLISHED BY THE COMPANY ON ITS WEBSITE?

A. Yes. In accordance with the Non-Unanimous Comprehensive Settlement Agreement ("Hosting Settlement Agreement") approved in consolidated Proceeding Nos. 16AL-0048E, 16A-0055E, and 16A-0139E, Public Service committed to developing a study (the "Red Light / Green Light" demarcation study) to make available possible interconnection points on its system for Community Solar Gardens ("CSG").[19] In accordance with the Hosting Settlement Agreement, the Company will undertake an effort to publish hosting capacity maps on its website that are updated approximately annually.[20] As part of the engineering process to review and update the hosting capacity maps the Company relies on a number of assumptions about the amount of load and generation on an individual feeder and for the most is a manual effort to identify the assumed load and generation that is used in the hosting capacity analysis. As noted above, the APT

[19] Proceeding Nos. 16AL-0048E, 16A-0055E, and 16A-0139E, Non-Unanimous Comprehensive Settlement Agreement, pp. 61–62 (filed Aug. 15, 2016).
[20]

improves the accuracy of the forecasted load and generation (and makes the date readily available as opposed to the current manual effort) which can be used for improving and streamlining the hosting capacity analysis and maps.

Q. HOW ELSE WILL THE APT BENEFIT CUSTOMERS?

A. Given the capabilities and benefits the APT will enable for our distribution planning processes, this investment is in the interest of both customers and the Company and will help the Company meet our regulatory requirements. The customer benefits include quantifiable benefits and other benefits that are more difficult to specifically quantify. Deployment of APT will include the retirement of the Company's current distribution forecasting tool which has nearly $90,000 in annual O&M costs. Additional benefits that the Company expects when compared to our existing tools and processes include:

- Annual deferral of distribution capital investments as a result of the tool's enhanced capabilities to forecast both load and generation;
- Hourly analysis for all measured points on the grid that examines the minimum and peak loading differentials, load shapes and more clearly shows the impact of DER;
- Improved load forecasting precision that can account for two-way power flows;
- Enables easier identification of opportunities for non-wires alternatives investments for projected overloads and contingencies;
- Processes forecasting scenarios within the tool, rather than requiring an outside, manual process;
- Enables analysis closer to the customer than the traditional feeder and substation analysis, to examine impacts of DER at a more granular level;
- Better integrates customer data, including from future AMI deployment;

- Aggregates forecasts to ensure better consistency with corporate-level forecasts, and better integration into other company planning processes

Q. WHAT IS DISTRIBUTION'S ROLE IN IMPLEMENTING THE APT?

A. As APT is a software tool, Business Systems is responsible for its for budget and implementation and Distribution is responsible for defining the business requirements and supporting the implementation and testing of the software tool. Mr. Reimer discusses both the deployment of APT and the costs forecast for APT.

B. <u>Other Capital</u>

Q. WHAT IS THE SUBSTATION COMMUNICATION PROJECT?

A. The Substation Communication project includes substation upgrades that are needed to support the installation of substation equipment for the FLISR, IVVO, and FAN projects. For instance, the new LTCs or feeder relays that are installed as part of the IVVO and FLISR projects may also require substation RTU upgrades due to the increased SCADA data needs of new LTC controls and feeder relays. Similarly, the substation battery may be near capacity and the addition of FAN equipment may necessitate an increase in the battery capacity at the substation.

Q. WHY DOES THE COMPANY HAVE A SEPARATE PROJECT FOR THESE TYPES OF SUBSTATION UPGRADES?

A. These types of upgrades are specific to each substation (and may not be necessary at each substation) when compared to the LTC upgrades for IVVO which need to be performed at each substation that the Company is enabling the IVVO functionality. In addition, upgrades like RTU replacements or increasing the battery capacity can provide benefits to multiple AGIS projects.

Q. HOW DOES THE SUBSTATION COMMUNICATION PROJECT SUPPORT THE OVERALL AGIS PROGRAM?

A. The advanced grid is highly dependent on information and the equipment to transport that information. While existing communication equipment in our substations has met today's need, AGIS's requirements can increase the data and communication requirements beyond the current capabilities of the existing substation equipment.

Q. WHAT IS DISTRIBUTION'S PROJECTED CAPITAL SPEND IN THE "OTHER" CATEGORY FOR AGIS?

A. Tables CSN-D-28 and CSN-D-29 provide a breakdown of Distribution's capital expenditures and capital additions forecast in the "Other" category for 2020 through 2025.

Table CSN-D-28
Other AGIS Distribution - Capital Expenditures
(Total Company)
(Dollars in Millions)

	2020	2021	2022	2023	2024	2025	Total
Other	1.91	2.95	3.55	9.95	4.50	0.00	22.86

Table CSN-D-29
Other AGIS Distribution - Capital Additions
(Total Company)
(Dollars in Millions)

	2020	2021	2022	2023	2024	2025	Total
Other	1.62	2.79	3.19	10.90	4.50	0.00	23.00

Q. HOW DID THE DISTRIBUTION BUSINESS AREA DERIVE THE INITIAL CAPITAL BUDGET FOR THIS "OTHER" CATEGORY?

A. The capital budget for the other category includes only the Substation Communication project for Distribution. As noted above the capital budget for APT is supported by Business Systems and is described in more detail by Mr. Reimer. The capital budget for the Substation Communication project is based on capital costs of similar type projects that the Company already undertakes such as RTU upgrades and the estimated numbers of upgrades that are expected to be needed to support he AGIS functionality at each substation.

X. AGIS GOVERNANCE

Q. IS THE COMPANY INSTITUTING CONTROLS TO ENSURE AGIS IMPLEMENTATION IS CONDUCTED EFFECTIVELY, AND WITHIN FORECAST?

A. Yes. The AGIS program has established distribution program governance processes, which were developed based on established Xcel Energy Enterprise methods. Project Management Office ("PMO") services include management of processes, governance structures, metrics, and reporting. The core PMO function provides Program Governance which includes Program Management, Resource Management, and Financial Management. A dedicated team has been established to develop, manage, and ensure quality and compliance to all governance processes.

Q. HOW DOES THE AGIS PROGRAM ENSURE EFFECTIVE COST CONTAINMENT RELATED TO THE AGIS PROJECTS?

A. The Company's AGIS governance includes Program Management, Resource Management, and Financial Management. Program Management includes Scope Change, Risk/Issue Management, and Work and Schedule Management. Resource Management includes on-boarding and off-boarding of AGIS personnel, resource demand and capacity planning, and resource forecasting. Financial Management includes financial forecasting, budget management, cost benefit analysis, and contract management. Controls are established to ensure that processes with appropriate approval levels are adhered to.

Q. WHAT IS THE COMPANY'S GOVERNANCE STRUCTURE FOR THE AGIS INITIATIVE?

A. A robust governance structure is necessary for any program of this size and scope, especially considering the technical and integrated nature of AGIS, the various operating and customer service areas of our business that support the initiative, and the coordination necessary to deliver value for our customers as Public Service implements AGIS. The Company has established a tiered governance structure for the AGIS initiative to provide the necessary controls and oversight that will enable us to achieve the desired customer and business outcomes. The program sponsors are responsible for approval of the overall strategy and funding as well as the overall program results. The program sponsors have instituted an executive-level Integration Council (IC) to ensure alignment of the enterprise vision and drive cross-workstream integration of the AGIS initiative. This council resolves execution issues and risks, and provides enterprise visibility to the design, program management, change management, and benefits realization anticipated from AGIS implementation. Any proposed changes are individually documented and brought to a change control meeting composed of program management and senior AGIS leadership. The program management leaders can approve administrative and low impact changes to the initiative. Any significant changes to costs, benefits, scope, schedule, or resources are elevated to the IC for review and approval to provide a consistent approach across the initiative.

Q. HOW WILL THIS STRUCTURE ENSURE APPROPRIATE OVERSIGHT OF AGIS IMPLEMENTATION?

A. Any significant changes to costs, benefits, scope, schedule, and resources are escalated to the Integration Council from the program management leadership team to provide a consistent approach across the initiative. Program leaders ensure that when risks and issues are identified that could affect costs, benefits, scope, schedule, or resources, they are documented, and a mitigation strategy developed. Any risks, issues or changes that meet predetermined thresholds are then escalated to the IC and, if necessary, to the Executive Sponsors for appropriate resolution. This hierarchy of approvals ensures that scope, schedule, and costs are documented and controlled in order to align with customer and Company check as the initiative proceeds.

A. <u>Program Management</u>

Q. WHAT IS PROGRAM MANAGEMENT?

A. Program management is an organizational effort designed to coordinate all projects necessary to incorporate the AGIS initiative into the current distribution system. Large, complex initiatives like AGIS must have established program management controls in order to ensure the effective use of resources, and thus optimal costs for the scope and benefits intended. There are various aspects of program management, some that are specific to a particular business area, and other applicable across all functional areas involved in implementation.

Coordination of projects through program management is driven through standardized project planning, governance, budgeting, and execution metrics methodology. Program management also provides essential corporate resources to ensure that the various individual AGIS projects are completed successfully. The program management team will coordinate the work required for the individual projects that will build the assets that make up the overall AGIS initiative. The program management team is also responsible for financial analysis and control, accounting, contract management, resource management, initiative governance, communications, and administrative assistance for each individual project and the overall AGIS initiative. The program management team will also track results, identify and determine if remedial action is necessary to keep the AGIS initiative on track, and monitor interdependencies between individual projects.

Given the size of this initiative, significant program management oversight is needed on a frequent and ongoing basis due to the highly interrelated and interdependent nature of the many components of the AGIS initiative at the individual project level. The project planning life cycle in broken into phases; Strategy, Planning, Initiation, Blueprinting, Design, Build, Test, Deploy, Warranty. Once a project has been initiated, each phase of the project's health is peer reviewed on a weekly basis. The weekly review includes, schedule, milestone, issues, risk, and budget. The Project Management office conducts a peer review of the overall AGIS budget on a monthly basis and provides the results to the Integration Council.

Q. PLEASE DESCRIBE THE COSTS ASSOCIATED WITH AGIS PROGRAM MANAGEMENT.

A. Each of the budgets for the AGIS projects includes capital costs for program management for 2020 through 2025, when the AGIS projects will be substantially completed. In addition, O&M costs associated with program management are included in the "Other" cost category for Distribution. The program management costs are discussed together below.

Q. WHAT ASPECTS OF PROGRAM MANAGEMENT ARE INCLUDED IN THE AGIS BUDGET?

A. Program management costs include:

- Change Management;
- Environment/Release Management;
- Finance;
- Project Management Organization;
- Security;
- Supply Chain;
- Talent Strategy;
- Business Readiness;
- End to End Testing; and
- Delivery and Execution Leadership.

Change management makes up the largest portion of the program management costs in the AGIS budget.

B. Change Management

Q. WHAT IS CHANGE MANAGEMENT?

A. Change management is a systematic approach to effectively executing and managing fundamental organization and process changes, such as when an electric utility implements a significant change to the distribution grid. The implementation of the AGIS initiative will impact and transform the job functions for many of the Company's employees. In order to manage this transformation and properly engage employees and external stakeholders to ensure a successful transition, a comprehensive change management plan is necessary. In the context of change management, stakeholders include any person, process, or entity that is affected by the implementation of the AGIS initiative. The three main elements of change management – prepare, manage, and sustain – each involve significant detailed analysis, action and documentation. The AGIS initiative has a dedicated team ensuring that there is an appropriate overall change management plan in place, and that the plan is resourced and thoughtfully executed.

Q. WHAT TYPES OF COSTS ARE ASSOCIATED WITH AGIS CHANGE MANAGEMENT.

A. The change management capital costs are needed to complete work throughout the development, deployment, and conclusion of on implementing the AGIS components. Specific tasks that will be capitalized are those that relate directly to design and deployment of assets, such as, but not limited to, the development of key design decisions, training development, functional alignment, integration reviews, program architecture documentation, technical change management, managing quality, and performing independent deliverable reviews. Change management also includes O&M costs related to strategic program oversight, communications and customer training, as well as incremental corporate services obtained in direct support of the AGIS initiative.

Q. PLEASE DESCRIBE THE OTHER TYPES COSTS RELATED TO AGIS PROGRAM MANAGEMENT AND HOW THOSE COSTS WERE DEVELOPED.

A. The other program management costs associated with AGIS implementation are described in below. As a general note, these functions will be performed using a combination of internal employees and external consultants, and the costs forecasts related to work performed by internal employees is incremental to the general corporate budget forecasts. I also note below where additional considerations were used in developing the specific cost forecasts.

- Environment/Release Management: These costs are related to performance and operating tests on the AGIS technology prior to deployment. This includes identification and remediation of issues in the software/hardware deployment and performance testing on the scalability requirements of certain AGIS technology.

- Finance: These costs include providing forecasting, budgeting, and reporting on the financial performance of the projects and the AGIS initiative. This includes internal reporting on monthly metrics and providing support in regulatory filings.

- Project Management Organization: These costs are related to governance activities for the projects and the overall AGIS initiative. This includes reporting on current project status, requirements for project change requests, and control of policies and guidelines designed to effectively govern the projects and AGIS initiative.

- Security: These costs are for work related to identifying security threats and issues on the AGIS technology prior to deployment. This includes identification and remediation of security threats in the software/hardware deployment and continuing requirements for effective cyber security programs. Security requirements for the AGIS initiative follow the corporate strategy and process as outlined in Mr. Reimer's testimony.

- Supply Chain: These costs include providing centralized supply chain support, including negotiation of large strategic contracts.

- Talent Strategy: These costs include providing support in staffing and alignment of the project and initiative teams. This includes alignment with long term strategic priorities and staffing levels designed around the implementation of the AGIS technology.

- Business Readiness: These costs relate to ensuring the business is ready to operate and sustain the new technology. The Business Readiness function ensures that the technology meets the expectations of the business, and that the business is appropriately prepared for the deployment of that technology. The overall goal of the Business Readiness function is to protect the value of the investments by ensuring the new technology is integrated seamlessly into the Company's day to day business.

- End to End Testing: These costs are related to testing full business process, including software, system interfaces and other technologies that support or enable the business process from start to finish using real-world scenarios to simulate and test performance after deployment. For the ADMS these costs include full validation of 2-way data transfer between ADMS and field devices. The E2E test also confirms that the field data is displayed accurately on the ADMS User Interface (UI). This testing phase is a normally expected and desired part of testing to determine the business' ability to utilize the business process in normal daily activities.

- Delivery and Execution Management: These costs include project and initiative leadership through the design, build, and deployment phases of the AGIS initiative. Delivery and Execution Leadership will provide the oversight and alignment of the project and initiative objectives to the strategic priorities of the Company and the Commission.

Q. ARE PROGRAM MANAGEMENT COSTS REASONABLE?

A. Yes. The Company determined the costs based on the need to build a program management team that will consist of internal employees, as well as the engagement of consultants. This approach is based on the Company's experience with program management and is consistent with its recent experience implementing the new general ledger and work and asset management systems.

Q. DID THE COMPANY DEVELOP CONTINGENCIES FOR PROGRAM MANAGEMENT?

A. Yes. The contingencies for program management are consistent with the contingencies proposed for the overall AGIS initiative but are less than the overall contingencies estimated for design, deployment, and operations of the other components of the initiative. They reflect the uncertainty around the costs that will be necessary for program management, which may not be fully understood until the final requirements for implementation in Colorado are known. Until design and engineering are complete, contingencies are necessary to account for the unknowns that are likely to develop during the processes and through the installation and operations phase.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COSTS IN THE "OTHER" CATEGORY THAT INCLUDES COSTS FOR PROGRAM MANAGEMENT THAT SUPPORT THE AGIS INITIATIVE?

A. Table CSN-D-30 provides a breakdown of Distribution's O&M expense forecast for the "other" category for 2021 through 2025 that includes costs associated with strategic program oversight, finance, program management, change management, talent strategy, business readiness, and delivery and execution management as described in this section.

Table CSN-D-30
Other AGIS Distribution – O&M Expenses
(Total Company)
(Dollars in Millions)

	2021	2022	2023	2024	2025	TOTAL
Other	2.17	2.05	1.10	1.10	0.97	7.39

Q. IN SUMMARY, WHY ARE THESE COSTS REASONABLE FOR CUSTOMERS TO SUPPORT?

A. AGIS is a transformational initiative for how the Company manages its distribution system and interacts with its customers, having a the robust program structure in place not only ensures that Public Service delivers each project but also ensures that Public Service prepares its employees and customers for the upcoming changes to maximize the benefits and value for customers.

XI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend that the Commission approve the proposed AGR and find that Distribution's AGIS capital and O&M budgets are a reasonable representation of the important grid advancement activities Public Service will undertake through 2025 on behalf of the Company and ultimately its customers.

Q. DOES THIS CONCLUDE YOU DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Chad S. Nickell

I am the Advanced Grid Intelligence and Security ("AGIS") Delivery Lead for Distribution for Xcel Energy. In my role 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.

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

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE NO. 1828-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8 - ELECTRIC TARIFF TO IMPLEMENT AN ADVANCED GRID RIDER TO BE EFFECTIVE ON AUGUST 17, 2020	**) PROCEEDING NO. 20AL-XXXXE**

AFFIDAVIT OF CHAD S. NICKELL
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Chad S. Nickell, being duly sworn, state that the Direct Testimony and attachments were prepared by me or under my supervision, control, and direction; that the Direct Testimony and attachments are true and correct to the best of my information, knowledge, and belief; and that I would give the same testimony orally and would present the same attachments if asked under oath.

Dated at Denver, Colorado, this 16 day of July, 2020.

Chad S. Nickell
AGIS Delivery Lead for Distribution for Xcel Energy

Subscribed and sworn to before me this 16 day of July, 2020.

JACOB BACHMAN
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20194010102
MY COMMISSION EXPIRES 3/15/2023