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

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RE: IN THE MATTER OF ADVICE LETTER NO. 1748-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**)**	**PROCEEDING NO. 17AL-____E**

DIRECT TESTIMONY AND ATTACHMENTS OF JOHN D. LEE

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

October 3, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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<u>SUMMARY OF THE DIRECT TESTIMONY OF JOHN D. LEE</u>

Mr. John D. Lee is Senior Director, Electric Distribution Engineering for Xcel Energy Services Inc. In this position he is responsible for directing the overall activities of Electric Distribution Engineering for Public Service Company of Colorado ("Public Service" or "Company"), one of four utility operating company subsidiaries of Xcel Energy Inc. His duties include, among other things, strategic system planning, distribution area engineering, distribution standards, lifecycle planning and investment delivery. He is also responsible for the creation, management, and forecasting of the electric distribution capital budgets.

In his Direct Testimony, Mr. Lee presents Public Service's technical strategy for the Advanced Grid Intelligence and Security ("AGIS") initiative in order to support capital and Operations and Maintenance ("O&M") cost recovery for 2017 and the 2018-2021 Multi Year Plan ("MYP"). In particular, Mr. Lee supports the following distribution capital expenditures, capital additions and O&M for the AGIS initiative.

Table JDL-D-1
AGIS DISTRIBUTION CAPITAL EXPENDITURES
Public Service (Total Company Electric)
(Dollars in Millions)[1]

Asset Class	AGIS Name	2016	2017	2018	2019	2020	2021
In CPCN	AMIe	.5	1.6	3.1	7.8	29.0	61.2
	FAN	0	.5	1.3	1.6	1.4	.2
	IVVO	.1	3.3	21.0	24.4	22.8	23.3
Not in CPCN	ADMS/GIS	.5	3.0	8.5	7.5	7.8	9.1
	FAN	.1	.7	.8	.8	.3	.2
	FLISR/FLP	1.8	2.9	5.6	5.6	6.2	12.2
	Adv Grid/Other	0	0	3.6	8.2	7.2	5.5
Total Public Service Electric		2.8	12.0	43.8	55.9	74.6	111.7

Table JDL-D-2
AGIS DISTRIBUTION OPERATING AND MAINTENANCE
Public Service (Total Company Electric)
(Dollars in Millions) [2]

Asset Class	AGIS Name	2016	2017	2018	2019	2020	2021
In CPCN	AMIe		.1	1.0	.7	2.6	4.2
	FAN		.1	.3	.3	.3	.1
	IVVO		.7	1.3	1.3	1.8	2.5
Not in CPCN	ADMS/GIS		.4	.8	.7	.5	.5
	FAN		.3	.4	.4	.1	.1
	FLISR/FLP		.1	.4	.6	.8	1.3
	Adv Grid/Other		.1	.2	.6	.5	.2
Total Public Service Electric			1.9	4.4	4.7	6.6	8.9

Company witness Ms. Lisa Perkett utilizes this capital information to develop the plant-related roll forward, which is in turn used by Company witness Ms. Deborah Blair to calculate the 13-month average plant in service balance included in the Company's January 1, 2017 through December 31, 2017 bridge year and the MYP. Moreover, the Company proposes to include forecasted capital for AGIS for 2017 through 2021 in the cost of service presented by Ms. Blair.

[1] Differences due to rounding.
[2] Differences due to rounding.

In support of these requests, Mr. Lee provides a technical overview of the foundational components of the AGIS initiative, which include the Advanced Distribution Management System ("ADMS"), Advanced Metering Infrastructure ("AMI"), the Field Area Network ("FAN"), Integrated Volt-VAr Optimization ("IVVO"), additional advanced applications including Fault Location Isolation and Service Restoration ("FLISR") and Fault Location Protection ("FLP") devices, and the Geospatial Information System ("GIS") data needed to operate the ADMS. While Company witness Ms. Alice Jackson explains that some of these components were the subject of a Certificate of Public Convenience and Necessity ("CPCN") recently received from the Colorado Public Utilities Commission ("Commission") and others are being carried out in the ordinary course of business, Mr. Lee walks through the objectives and implementation plan for the overall AGIS initiative, including budgeting and costs, deployment activities and timelines, and cost control and governance. Mr. Lee explains the robust planning and budgeting process, as well as the Company's work to ensure the projects are implemented for the benefit of customers. Mr. Lee also discusses the implementation processes and oversight planned for each component from a Distribution Business Area perspective, working in tandem with Company witness Mr. David Harkness who supports the Business Systems/Information Technology ("IT") aspects of the AGIS projects.

Mr. Lee also describes the Innovative Clean Technology ("ICT") program, supports the implementation of the Panasonic Project and the Stapleton Project (the "ICT Projects"), and explains the Company's cost projections and management of these projects. Both ICT Projects involve the evaluation of energy storage technology installed on distribution feeders that have relatively high penetrations of distributed solar generation. Mr. Lee explains how the ICT Projects are being implemented consistent with the ICT settlement approved by the Commission in Decision No. C16-0196, mailed March 8, 2016, and supports the cost recovery associated with these ICT Projects presented by Company witness Ms. Blair.

Finally, Mr. Lee discusses the Company's current excellent reliability metrics, including improvements in comparison to prior Quality Service Plan ("QSP") filings and first/second quartile performance in System Average Interruption Duration Index ("SAIDI") compared to Company peers. Mr. Lee notes that the AGIS programs will help continue to maintain the Company's reliability performance at levels that provide strong results for customers as compared to industry averages. These reliability goals reflect part of the potential value of the AGIS initiative.

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DIRECT TESTIMONY AND ATTACHMENTS OF JOHN D. LEE

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ANSI	American National Standards Institute
BESS	Battery Energy Storage System
CCOD	City and County of Denver
Commission	Colorado Public Utilities Commission
Company	Public Service Company of Colorado
CPCN	Certificate of Public Convenience and Necessity
CPCN Projects	AMI, IVVO, and the components of the FAN that support these components
CPE	Customer Premise Equipment
DA	Distribution Automation
DIA	Denver International Airport
DER	Distributed Energy Resources
DR	Demand Response
DSM	Demand Side Management
ECT	Electric Continuity Threshold
EPRI	Electric Power Research Institute
ERT	Electric Restoration Threshold
ESB	Enterprise Service Bus
ESIC	Energy Storage Integration Council
FAN	Field Area Network
FLISR	Fault Location Isolation System Restoration
FLP	Fault Location Prediction
GFCI	Ground Fault Circuit Interrupter
GIS	Geospatial Information System
HAN	Home Area Networks
ICT	Innovative Clean Technology
IEEE	Institute of Electrical and Electronics

Acronym/Defined Term	Meaning
IT	Information Technology
IVVO	Integrated Volt-VAr Optimization
kVAr	Kilovolt-Amperes Reactive
kW	Kilowatt
kWh	Kilowatt Hours
LTCs	Load Tap Changers
MYP	Multi Year Plan
NOC	Network Operations Center
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PESCO	Panasonic Enterprise Solutions Company
PTMP	Point-to-Multipoint
Public Service	Public Service Company of Colorado
PV	Photovoltaic
QSP	Quality Service Plan
RF	Radio Frequency
RFP	Request for Proposal
RFx	Request for Information and Pricing
ROW	Right of Way
RTU	Remote Terminal Units
RWT	Reliability Warning Threshold
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SVC	Secondary Static VAr Compensators
TOU	Time-of-Use
WAN	Wide Area Network
WiMAX	Worldwide Interoperability for Microwave Access
WiSUN	802.15.4g Standard
Xcel Energy	Xcel Energy, Inc.
XES	Xcel Energy Services Inc.

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DIRECT TESTIMONY AND ATTACHMENTS OF JOHN D. LEE

I. INTRODUCTION, QUALIFICATIONS AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John D. Lee. My business address is 1123 W. 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 the Senior Director, Electric Distribution Engineering. 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 "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 Senior Director, Electric Distribution Engineering, I am responsible for directing the overall activities of Xcel Energy Electric Distribution Engineering, including strategic system planning, distribution area engineering, distribution standards, lifecycle planning, and investment delivery. My duties include the creation, management, and forecasting of the electric distribution capital budgets across all Xcel Energy utility subsidiaries. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to discuss and support the technical strategy for implementation of Public Service's Advanced Grid Intelligence and Security ("AGIS") initiative, which will result in an advanced electric distribution grid in the Company's Colorado service territory. I explain how the Company is moving forward from the settlement and Certificate of Public Convenience and Necessity ("CPCN") for AGIS ("AGIS CPCN" or "Grid CPCN") in Proceeding No. 16A-0588E to implement the foundational AGIS CPCN projects in a prudent manner, while also implementing those components of AGIS that are being conducted in the ordinary course of business. I note that Company witness Ms. Alice Jackson discusses the policy aspects of the AGIS initiative for this filing, and that Company witness Mr. David Harkness provides additional support for the implementation of AGIS projects from an Information Technology perspective.

I also discuss the Innovative Clean Technology ("ICT") projects, which include two battery projects, including the implementation of the project and the work that the Distribution Business Area will undertake to complete that implementation, and the costs of the project. Through my discussion of the AGIS foundational projects and the ICT projects, I support the cost recovery of these projects in the manner described by Company witness Ms. Deborah Blair. Finally, I discuss the Company's distribution reliability achievements to date and its plans for additional enhancements in the years ahead.

Q. WHAT IS "AGIS"?

A. AGIS is a long-term strategic initiative to transform our electrical distribution business to enhance security, efficiency, and reliability, to safely integrate more distributed resources, and to enable improved customer products and services. 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 developed and enhanced technology to increase grid reliability, transparency, efficiency, and access. Overall, the AGIS platform consists of multiple programs that will ultimately work together to support improved distribution technology, a stronger economy, empowered customer choice, and improved energy management and savings. Consistent with related initiatives by utilities around the country, it is the natural next step in the development of our distribution grid.

Q. WHAT ARE THE FOUNDATIONAL PROGRAMS THAT MAKE UP THE AGIS INITIATIVE?

A. The advanced grid achieved through the Company's AGIS initiative, involves the following key programs: Advanced Distribution Management System ("ADMS"); Advanced Meter Infrastructure ("AMI"), Field Area Network ("FAN"); Intelligent Field Devices such as Integrated Volt VAr Optimization ("IVVO"), Fault Location Isolation and Service Restoration ("FLISR"), and Fault Location Prediction ("FLP"); and the Geospatial Information System ("GIS").

In addition to the foundational programs, Innovative Clean Technology ("ICT") battery test projects, Panasonic and Stapleton, are considered to be programs within the AGIS initiative because they were developed to test certain advanced grid functionalities.

Q. ARE YOU THE ONLY WITNESS WHO PROVIDES SUPPORT FOR COST RECOVERY OF THE AGIS PROJECTS?

A. No. My testimony provides the technical strategy and information for the overall AGIS initiative, and also breaks down the work on individual AGIS projects that will be completed by the Distribution Business Area. Company witness Ms. Alice Jackson supports the AGIS implementation from a policy perspective, including providing an overview of the AGIS CPCN settlement. Mr. David Harkness supports the Information Technology ("IT") components of AGIS from a Business Systems business area perspective. In Sections IV and V of my Direct Testimony, I specifically discuss the work to be done by Distribution versus the planning and work being completed by Business Systems.

Q. BY WAY OF OVERVIEW, WHAT IS THE COMPANY PROPOSING WITH RESPECT TO COST RECOVERY OF THE AGIS PROJECTS, INCLUDING THE ICT PROJECTS?

A. The Company is proposing to recover the 2017-2021 capital and O&M associated with the foundational AGIS projects through the MYP in this rate case. With respect to the ICT projects, the Company proposes to amortize the 2017 O&M and defer O&M during the 2018-2021 MYP. The Company is also proposing to amortize the ICT capital. I provide this overview to ground the following discussion of and support for the work on the AGIS and ICT projects; however, Company witness Ms. Blair supports the Company's proposed cost recovery in development of the revenue requirement.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. To address the technical strategy for AGIS, Section II of my Direct Testimony first provides an overview of the AGIS initiative and then I discuss each of the foundational components of AGIS in detail. In Section III, I detail the overall implementation plan and costs for AGIS from 2016 (the Historic Test Year or HTY), 2017, and 2018 through 2021 consistent with the Commission-approved settlement agreement in Proceeding No. 16A-0588E related to the Certificate of

Public Convenience and Necessity ("CPCN") for AGIS ("AGIS CPCN" or "Grid CPCN"). In Section IV, I detail the type of work that the Distribution Business Area will complete and the costs specific to Distribution that will be incurred for each year in the 2018-2021 Multi-Year Plan ("MYP"). Finally with respect to AGIS, in Section V I discuss the individual AGIS component implementation, focusing on those areas where the Distribution Business Area is taking the lead on budget development, planning, and deployment.

In Section VI of my Testimony I discuss the ICT projects, and I discuss our Reliability goals and achievements in Section VII to underscore the importance of the AGIS cost investments. In sum, the Company's proposal is intended to illustrate and seek Commission support for the Company's business plan for implementation of the AGIS initiative, including both the AGIS CPCN and ordinary course foundational projects and the ICT projects.

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

A. Yes, I am sponsoring the following:

- Attachment JDL-1: Illustration of the principal components of the fan;
- Attachment JDL-2: AGIS Distribution Capital Additions;
- Attachment JDL-3: ADMS Capital and O&M Budget;
- Attachment JDL-4: AMI Capital and O&M Budget;
- Attachment JDL-5: FAN Capital and O&M Budget;
- Attachment JDL-6: IVVO Capital and O&M Budget;
- Attachment JDL-7: FLISR Capital and O&M Budget;
- Attachment JDL-8: AGIS Other Capital and O&M Budget;
- Attachment JDL-9: AGIS Other Capital and O&M Budget;
- Attachment JDL-9: ICT Panasonic Project Budget; and
- Attachment JDL-10: ICT Stapleton Project Budget.

II. <u>THE AGIS INITIATIVE AND ITS FOUNDATIONAL COMPONENTS</u>

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

A. In this Section of my Direct Testimony I discuss the foundational components of the AGIS initiative in detail.

Q. CAN YOU FIRST PROVIDE AN OVERVIEW OF EACH OF THE AGIS FOUNDATIONAL COMPONENTS?

A. Yes. These components include:

- **<u>Advanced Distribution Management System:</u>** ADMS will provide 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. It will manage the complex interaction of Distributed Energy Resources ("DER"), outage events, feeder switching operations, and the advanced applications and field devices 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 enables each of the other AGIS components described below.
- **<u>Advanced Meter Infrastructure:</u>** AMI meters are able to measure and transmit voltage, current, and power quality data and can act as a "meter as a sensor," enabling near real-time monitoring between the meter and

ADMS. These meters provide information about customer usage and will enhance our ability to send price signals to customers, allow for new rate structures that will allow 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.

- **Field Area Network:** The FAN is the communications network that will enable communications between the communications infrastructure that already exists at the Company's substations, the ADMS, and the new intelligent field devices associated with advanced applications as described immediately below. 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.
- **Advanced Applications for Intelligent Field Devices:** The following advanced applications and associated field devices will support a more advanced grid:
  - Integrated Volt-VAr Optimization ("IVVO") is an application that automates and optimizes the operation of the distribution voltage regulating and VAr control devices to reduce electrical

losses, electrical demand, and energy consumption, and provides increased distribution system injection capacity to host DER.

  - Fault Location Isolation and Service Restoration ("FLISR") involves 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.
  - Fault Location Prediction, or 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 the fault.

- **<u>Geospatial Information System ("GIS"):</u>** Provides location information about all physical assets that make up the electric distribution system. The records also include specification information regarding the physical assets, such as a distribution feeder's size. ADMS will use the location and specification information to maintain the as-operated electrical model and advanced applications.

Below I discuss each of the foundational AGIS programs in more detail, much as the projects were described in our CPCN filing, to provide the background on the work the Company plans to implement the AGIS initiative during the MYP.

A. <u>Advanced Distribution Management System (“ADMS”)</u>

Q. WHAT IS THE ADMS?

A. As mentioned above, 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. The key objectives of an ADMS are to improve the reliability and quality of service in terms of reducing outages, minimizing outage time, and maintaining acceptable voltage levels on the system. An 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. It will 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.

Q. WAS ADMS PART OF THE AGIS PROGRAMS APPROVED IN THE GRID CPCN PROCEEDING?

A. No. ADMS is a component of AGIS that the Company is implementing through the ordinary course of business.

Q. HOW WILL ADMS IMPROVE THE WAY THE COMPANY CURRENTLY MONITORS THE DISTRIBUTION SYSTEM?

A. 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. ADMS will also make adjustments 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?

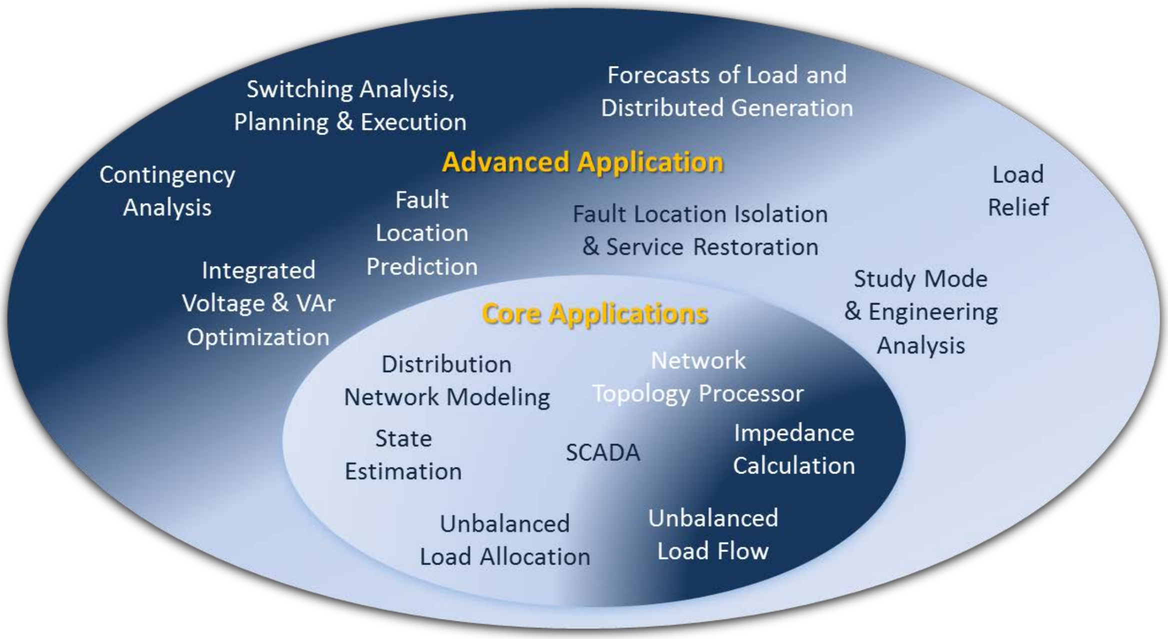
A. ADMS will utilize an enhanced distribution grid model that will include substations, feeders, taps, and services, in one user interface, to more accurately represent the entire distribution grid. Because the Geospatial Information System ("GIS") will provide the nominal geo-spatial electrical model to ADMS, accuracy of the GIS model including impedance data will be essential, because this data will improve the model when operating advanced applications like IVVO and FLISR. ADMS will maintain the as-operated GIS 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 will have core applications, which will make up the foundation of ADMS, as well as advanced applications. 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.

The ADMS advanced applications will utilize the core applications and provide additional capability. Public Service will 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. The applications discussed above are listed in Figure JDL-D-1 below.

Figure JDL-D-1



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 II.B and Section II.C, 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 WILL BE THE PHYSICAL COMPONENTS OF ADMS?

A. ADMS will be composed of hardware, software, distribution SCADA, and an impedance model, which is an accurate electrical representation of the distribution grid, including substations, core, and advanced applications. ADMS will leverage sensor data for use by the core and advanced applications to make accurate and informed decisions to manage power flow on the distribution grid. The Distribution Business Area has primary responsibility for the Geospatial

Information System ("GIS") data portion of the ADMS, which is described later in this Direct Testimony, whereas the Business Systems area has responsibility for the ADMS model, including hardware, software, and Information Technology integration.

Q. WILL ADMS HAVE SENSORS?

A. No, sensors will not be integral components of ADMS. Instead, ADMS will utilize voltage and power quality data provided by sensors and equipment located on the grid. For example, AMI meters will be able to measure and transmit voltage, current, and power quality data and can act as a "meter as sensor" providing near real-time monitoring information between the meter and ADMS. Other devices that will provide sensor data for ADMS to accurately calculate power flow on the grid include distribution automated device Remote Terminal Units ("RTU") and power sensors that are located on feeders.

Q. DO YOU FORESEE FURTHER USES FOR ADMS IN THE FUTURE?

A. Yes. 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 it to limit the potential negative impacts of these technologies on traditional electric customers, such as higher-than-necessary voltage that results from greater penetrations of solar on the distribution feeders. 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.

B. <u>Advanced Metering Infrastructure</u>

Q. WHY IS PUBLIC SERVICE TRANSITIONING TO AMI TECHNOLGY?

A. Advanced meters can provide substantial near real-time data that can be used to improve the Company's ability to monitor, operate, and maintain the distribution grid. Advanced meters can be used to verify power outages and service restoration. Improved reliability monitoring can lead to improved outage response, proper protection system analysis and ultimately reduce outages. Advanced meters can also provide improved voltage monitoring and management, support better load studies and analysis resulting in improved planning and design, and be used to support additional systems such as an ADMS with applications like IVVO that will promote energy efficiency and peak shaving. Advanced meters will also be able to support new rate designs that cannot be supported by the Company's current AMR meters.

Q. WERE ADVANCED METERS PART OF THE AGIS PROGRAMS APPROVED IN THE GRID CPCN PROCEEDING?

A. Yes. The Commission approved the Company's implementation of advanced meters as part of the Grid CPCN proceeding.

Q. PLEASE DESCRIBE AMI IN MORE DETAIL.

A. AMI is an integrated system of advanced meters, communications networks, and data management systems that enable two-way communication between utilities' business and operational data systems and meters enabling added benefits for customers and the utilities. Advanced meters are the key endpoint component of an AMI system that measures, stores and transmits metering quantities, including energy usage information at customer locations. The components of an advanced meter include (i) the meter itself, (ii) a two-way radio frequency communication module, and (iii) an internal service switch.

Q. CAN YOU DESCRIBE THE FUNCTION OF THE ADVANCED METER ITSELF?

A. Yes. The advanced meters can be remotely configured to measure bi-directional and/or time-of-use ("TOU") energy consumption in kilowatt hours ("kWh") and demand in kilowatts ("kW"). A meter that is configured for bi-directional energy measurement measures energy provided from the Company to the customer and also measures energy provided from the customer to the Company. Net metering for a solar customer is an example of metering with bi-directional functionality. The consumption of kWh/kW can be recorded by the advanced meter in intervals as short as five or 15 minutes, or longer intervals if desired.

Additionally, advanced meters 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; and,

Perform and transmit meter diagnostics pertaining to the correct functioning of the meter and the communications module.

Q. CAN YOU DESCRIBE THE FUNCTION OF AN ADVANCED METER'S TWO-WAY RADIO FREQUENCY MODULE?

A. Yes. The radio frequency communication module will utilize the Company's communications network, as I describe later in my testimony, to provide two-way communication between the meter and the AMI head-end application, which is the operating software system that is used to send data requests and commands to an advanced meter, and receive data from an AMI capable meter. Such communications include:

- Transmitting the measurements performed, and alarm conditions and events detected by the meter to the head-end application;
- Receiving commands from the head-end application to send specific meter measurements, alarms and events, reset demand registers, configure the meter to measure specific sets of energy parameters or time of use intervals and data recording intervals and channels;
- Remotely performing meter firmware upgrades; and

- Receiving commands from the head-end application to open or close the internal service switch and communicate its status.

Additionally, the AMI meter's communication module can act as a two-way repeater for other advanced meters on the communication network.

Q. PLEASE DESCRIBE THE FUNCTION OF AN ADVANCED METER'S INTERNAL SERVICE SWITCH.

A. The internal service switch remotely connects or disconnects power to the customer's electric service upon command from the head-end data application. The internal service switch is available on 200 ampere single-phase AMI meters, which includes the residential and small commercial customers in the Company's service territory.

Q. HOW WILL ADVANCED METERS WORK WITH THE OTHER COMPONENTS OF THE AGIS INITIATIVE?

A. The advanced meters will collect the data that will be communicated through the FAN, which I describe in more detail below, to the head end system, ADMS, which I also describe in more detail below, to allow the Company to more efficiently manage the distribution system.

C. The FAN

Q. WHY IS PUBLIC SERVICE IMPLEMENTING FAN TECHNOLOGY?

A. The FAN is a wireless communications network that provides connectivity between substation and field devices up-to and including the customer meter. Through the substation's connectivity to the existing Wide Area Network

("WAN"), the FAN enables back-office applications to directly communicate with field devices providing near real-time usage information for both customers and the Company.

Q. WHAT IS THE FAN?

A. Public Service's FAN will be a resilient communications network that enables communications between the Company's existing substations and new or planned field devices. The principal purpose of the FAN is to enable two-way communication of information and data to and from the existing infrastructure at the Company's substations and the field devices. A FAN will securely and reliably address the need for increased communication capacity that arises from grid advancements.

The FAN will be a single, general-purpose, wide area wireless networking resource that will be capable of simultaneously accessing these diverse types of endpoints, each with their own performance requirements, on Public Service's electric system. These endpoints will include a variety of field devices including reclosers, feeders, electric meters, capacitor banks, and virtually any other field device capable of communications, including gas regulators at a future time. The FAN will be able to communicate with other endpoints in the future as those devices are installed or upgraded with communications modules, and those devices could become part of the Wireless Smart Utility mesh network. Public Service's FAN will consist of layers (also referred to as "tiers") of secure wireless radio networks and supporting information technology ("IT") infrastructure that are designed to provide network access to utility endpoints, and to serve as a reliable communications medium for the wide variety of legacy, current-, and future-state monitoring and control applications.

Q. WHAT ARE THE PRINCIPAL TECHNOLOGIES THAT WILL BE USED BY PUBLIC SERVICE'S FAN?

A. The FAN will provide connectivity between the substation and field devices, up to and including the customer meter. It will use two wireless technologies: (a) a Wireless Smart Utility Network ("WiSUN") mesh network; and (b) a Worldwide Interoperability for Microwave Access ("WiMAX") network. I describe these two components in more detail below. Public Service's CPCN Projects Application in this proceeding covers the WiSUN mesh network, which is the specific technology necessary to support the AMI program and the IVVO application.

Q. WILL THE FAN BE CONNECTED TO PUBLIC SERVICE'S CURRENT COMMUNICATIONS NETWORK?

A. Yes, the FAN will be connected to Public Service's pre-existing Wide Area Network ("WAN"). The connections will be primarily at substations on the distribution system.

Q. PLEASE DESCRIBE THE WAN.

A. Public Service's WAN is a communications network primarily composed of private optical ground wire fiber and a collection of routers, switches, and private microwave communications that are supplemented by leased circuits from a variety of carriers as well as satellite backup facilities. The WAN is 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 WAN is monitored at all times by the Network Operations Center ("NOC").

Q. DOES THE COMPANY PLAN TO UPGRADE ITS WAN TO SUPPORT THE FAN?

A. Yes. Public Service plans to increase the WAN's capacity, security, and capabilities to support the anticipated volume of data that will be communicated over the network, for reasons both independent of and including the network performance required by the FAN deployment. This includes increasing the reach of the network as well as improving the redundancy of various components to meet the requirements of the applications using the FAN.

Q. WAS THE FAN APPROVED IN THE GRID CPCN PROCEEDING?

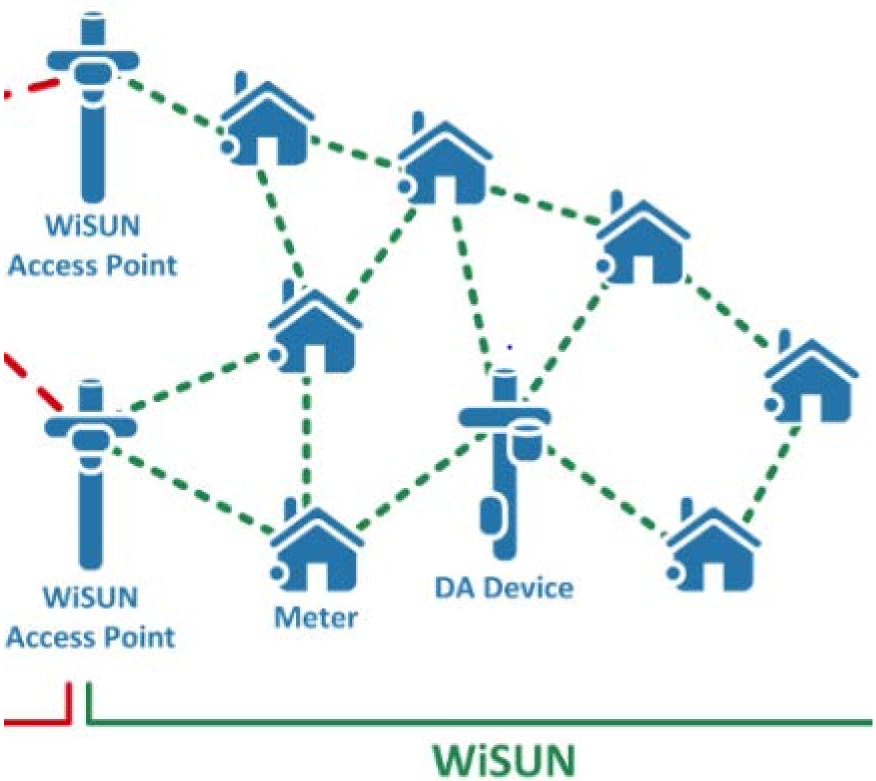
A. In part. The WiSUN portion of the FAN, which I describe in more detail below, was approved as part of the Grid CPCN proceeding. The Company did not request approval of the WiMAX portion of the FAN or updates to the WAN as part of the CPCN and intends to implement those components through the ordinary course of business.

Q. WHAT ARE THE PRINCIPAL COMPONENTS OF THE FAN?

A. The FAN will be a wireless communications network that provides connectivity between the substation and field devices, up-to and including the customer meter. The FAN will consist of two separate wireless technologies: (a) a lower-speed mesh network called WiSUN; and (b) a high-speed point-to-multipoint ("PTMP") network referred to as WiMAX. Attachment JDL-1 provides an illustration of the principal components of the FAN.

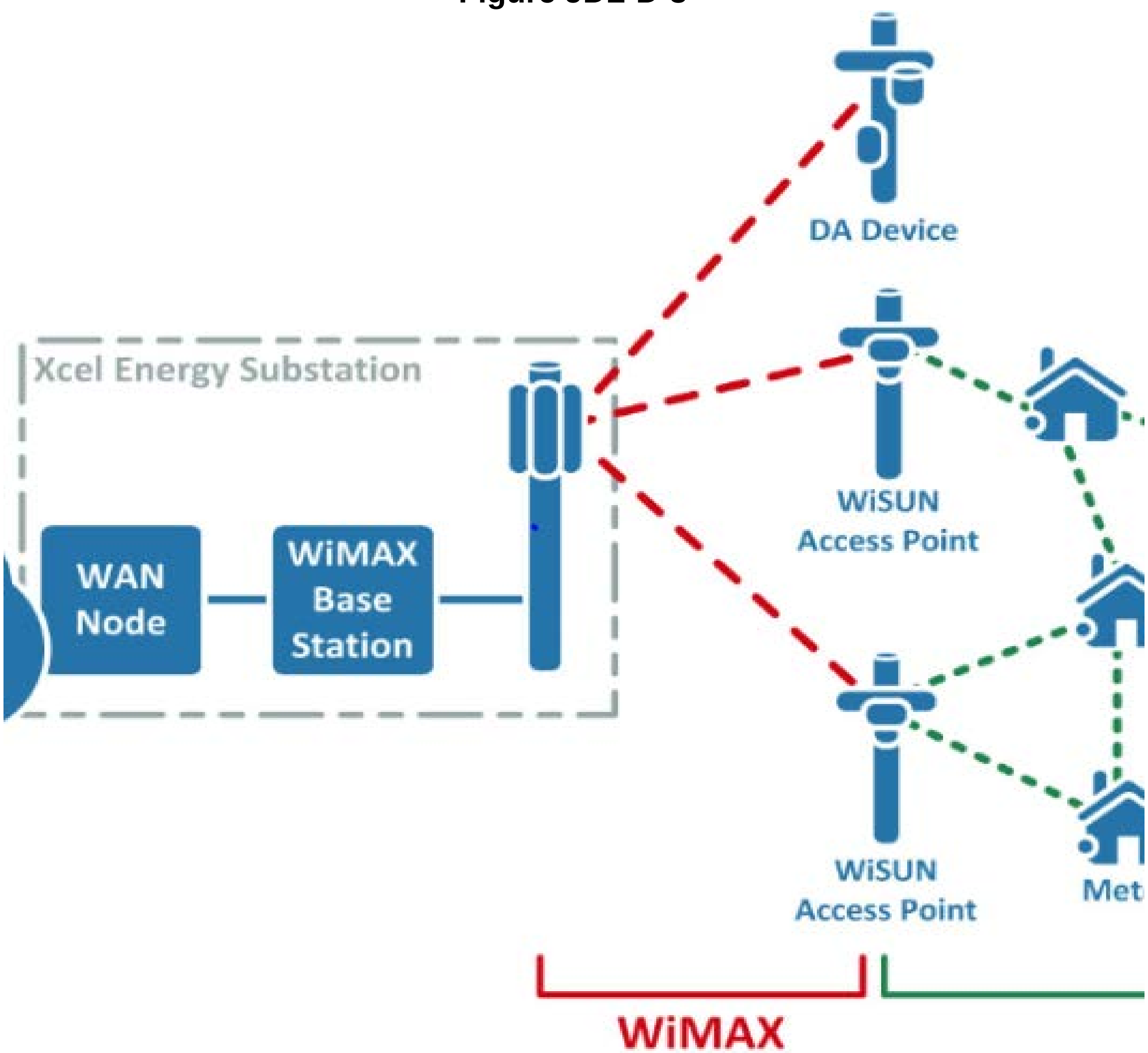
The WiSUN mesh network will communicate directly with the AMI infrastructure (such as the advanced meters) and the Distribution Automation ("DA") field devices used for the IVVO advanced application. The flow of communications between field devices, meters, and WiSUN access points through a mesh-styled network is shown in Figure JDL-D-D-2, below, which is a portion of Attachment JDL-1.

Figure JDL-D-2



The WiMAX network, illustrated below in Figure JDL-D-3 (also a portion of Attachment JDL-1), will provide redundant, reliable, and secure connectivity between the WiSUN mesh network and the Company's WAN. The DA and WiSUN devices connect to the WiMAX base stations via wireless communication modules that are integral to those devices. The components of the WiMAX network are discussed in more detail later in my testimony.

Figure JDL-D-3



Through the substation's connectivity to the WAN, the FAN (including the downstream WiSUN mesh network and the WiMAX network) will enable the Company's advanced applications (such ADMS and AMI, and sub-applications, including IVVO, FLISR, FLP, and GIS) to communicate with the field devices that implement those applications and sub-applications.

Q. PLEASE DESCRIBE THE INFRASTRUCTURE AND DEVICES THAT WILL BE INSTALLED AS PART OF THE WiSUN MESH NETWORK TO SUPPORT AMI AND IVVO.

A. The core mesh infrastructure will consist of two main device types: (1) access points, and (2) repeaters.

An access point is a device that will link the Company's endpoint devices that are enabled with wireless communication modules with the rest of the Company's communications network. The access points will wirelessly connect directly to backhaul (which is an intermediate link in the communications network—WiMAX, in this case) in order to pass traffic between the mesh network and the WAN. The term "traffic" refers to the actual digits and bytes of data that flow over the wired and wireless networks. Access points will extend the reach of Public Service's communications network and will define the boundary of the mesh itself.

Repeaters are range extenders and are used to fill in coverage gaps where devices would be otherwise unable to communicate.

These two device types will be principally located on distribution poles and other similar structures.

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. The radio frequency ("RF") communication modules in these devices will enable two-way communication between the AMI meters and the mesh network.

The term "mesh" refers to the network's topology, which resembles the interlaced design of mesh material, as shown in Figure JDL-D-3. All nodes on the network will relay data and cooperate in the distribution of that data in the network. The mesh design provides redundancy benefits, which are described in more detail below.

Q. PLEASE EXPLAIN THE TERM "WISUN."

A. WiSUN is the commercialized (public) name for the Institute of Electrical and Electronics Engineers' dr802.15.4g standard, and operates on the unlicensed 900 MHz spectrum. (The WiSUN naming convention is similar to how "Wi-Fi" is the commercial name for IEEE's 802.11 standard, which is used throughout the general public.) This standard for local and metropolitan area networks is well-accepted in the utility and communications industries. WiSUN can wirelessly connect meters, sensors, distribution devices, street lights, and signal repeaters to create a robust and reliable wireless network. Xcel Energy, on behalf of Public

Service and the other operating companies, participates as a full member in the WiSUN Alliance with other utilities and equipment manufacturers. By selecting a technology that conforms to the IEEE standard, Public Service will ensure the interoperability of the FAN with other systems.

Q. PLEASE DESCRIBE THE INFRASTRUCTURE AND DEVICES THAT WILL BE INSTALLED AS PART OF THE WIMAX NETWORK.

A. The WiMAX network will consist of two main components: (1) base stations, and (2) customer premise equipment ("CPE"). 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.

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 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 in order to ensure an appropriate height. In some cases, new poles may need to be deployed if a structural analysis of the designated existing poles indicates that added weight would cause a stability issue. CPEs will be mounted on distribution poles in the field of operation.

Q. PLEASE DESCRIBE THE FUNCTION OF EACH OF THESE DEVICES.

A. Base stations will communicate with CPEs in the field and, through the substations' connection to the WAN, enable end-to-end communication between the intelligent field devices and the Company's advanced applications and other back office applications. "Back office" applications and systems are those that actually use and manipulate the data and perform specific business functions, including energy management system applications.

In the case of a CPE that is connected to a WiSUN access point, this will further enable the back office applications to communicate with any device accessible to that access point's connections to the mesh network. For any particular mesh "cluster" (that is, a logical collection of mesh nodes), there will be multiple access points connected to WiMAX that will provide redundant paths of communication to the WAN. This will result in a more reliable, robust field area network.

Q. PLEASE EXPLAIN THE TERM "WIMAX."

A. WiMAX is the commercialized name for the IEEE's 802.16 series of standards. The WiMAX PTMP network will be based in Public Service's substations and will enable high-speed connectivity at locations across the distribution system. The WiMAX network will wirelessly connect directly to devices on the Company's distribution feeder lines as well as provide the secure, reliable connectivity between Public Service's WAN and WiSUN networks. Xcel Energy, on behalf of Public Service and the other operating companies, participates fully as a member of the WiMAX Forum, an industry group tasked with the continued development, maintenance, and certification of products for the 802.16 standards. By selecting a technology that conforms to the IEEE standards, Public Service will ensure the interoperability of the FAN with other systems.

Q. HOW WILL THE WIMAX NETWORK BE CONNECTED TO, AND INTERFACE WITH, THE WISUN MESH NETWORK?

A. The WiMAX network and WiSUN mesh network will communicate wirelessly as the WiSUN mesh access points communicate with the CPEs that make up the WiMAX network, and the CPEs in turn communicate back to the base stations at the substation.

Q. HOW WILL THE WIMAX NETWORK BE CONNECTED TO, AND INTERFACE WITH, THE COMPANY'S WAN?

A. The WiMAX base stations will be connected to the pre-existing WAN connections at the substation, which, in turn, will enable connectivity back to the data center locations. This connection at the substation will be via private fiber or alternate cabling within the substation from the WiMAX base station radios to the routers at the substations which are connected to the WAN. There may be rare instances in which WiSUN devices will be connected directly to the WAN, when WiMAX is not needed.

Q. WILL THE WISUN AND WIMAX NETWORKS BE DEPLOYED THROUGHOUT THE COMPANY'S ENTIRE SERVICE TERRITORY?

A. No. In limited circumstances where deployment of the WiSUN mesh and WiMAX networks is not practical (such as remote locations on the edge of Public Service's distribution system), Public Service may utilize cellular or other wireless technologies as part of its comprehensive FAN solution. While these technologies are not adequate to support AMI as a whole, as I discuss later in my testimony, they provide alternatives in limited situations. In these instances, information such as data from AMI meters will be transmitted to the Company's WAN over an alternate technology.

Q. HOW WILL THE FAN SUPPORT OR INTERACT WITH ADMS?

A. The FAN infrastructure will provide data from field devices to a common Enterprise Service Bus ("ESB") via the WAN, which will then deliver data to ADMS. An ESB is a software architecture used for enabling communication between multiple mutually interacting software applications. The ESB will also receive commands from ADMS that will be delivered to the devices connected to the FAN via the WAN. The FAN enables data and information from field devices to be communicated to ADMS, and also enables commands to be transmitted to the field devices from ADMS.

Q. HOW DOES THE FAN SUPPORT OR INTERACT WITH AMI AND IVVO?

A. An AMI system is an integrated communication system that involves the FAN and the advanced meters. The WiSUN integrates with the advanced meters because the meters include a communication module that forms the majority of the mesh network. The mesh network allows the advanced meter to communicate its measurement data, power status, voltage current, usage history, and peak demand information back to the Company. Additionally, the FAN integrates with IVVO because the advanced meters voltage information is communicated to the Company via the FAN. Receiving this information allows the Company to increase or decrease voltage to the optimum level on a system wide basis while ensuring all customers are within the acceptable voltage range allowable under the Company's tariffs.

Q. HOW WILL THE FAN SUPPORT OR INTERACT WITH FLISR (AND FLP)?

A. The FLISR/FLP distribution equipment (*i.e.*, feeder-level devices), that I will describe in more detail below, will have embedded communication modules that will communicate with access points in the mesh network or directly to WiMAX CPEs.

D. Integrated Volt-VAr Optimization ("IVVO")

Q. WHAT IS IVVO?

A. As mentioned above, IVVO stands for Integrated Volt-VAr Optimization. IVVO is an advanced application that automates and optimizes the operation of the distribution voltage regulating devices and VAr control devices to achieve operating objectives, including:

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

Q. WAS IVVO PART OF THE AGIS PROGRAMS APPROVED IN THE GRID CPCN PROCEEDING?

A. Yes. The Commission approved the Company's implementation of IVVO as part of the Grid CPCN proceeding.

Q. WHY IS PUBLIC SERVICE IMPLEMENTING IVVO TECHNOLOGY?

A. The current 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 Company's proposed IVVO application will allow voltage to be monitored along the entire length of the feeder and at selected end points (rather than only at the substation). This insight into the voltage levels will allow the Company to utilize lower voltages across the entire feeder at most times. This will result in reduction in distribution electrical losses; reduction in electrical demand; reduction in energy consumption; and increased capacity to host DER.

Fundamentally, the IVVO is a demand side management ("DSM") tool that controls voltage without requiring behavioral changes from customers.

Q. WHY IS VOLTAGE MANAGEMENT ON AN ELECTRIC DISTRIBUTION SYSTEM IMPORTANT?

A. Maintaining proper voltage levels throughout the electric distribution system is one of the most important challenges utilities face. Utilities seek to provide electric service to customers within a specific voltage range because customer equipment, appliances, and devices may not operate satisfactorily when electricity is supplied at voltages outside of the appropriate range. Customer demand for electricity changes throughout the day, which means the power flowing through distribution systems and voltage levels on feeders increase and decrease throughout the day to meet changing loads.

Q. HOW WILL THE TECHNOLOGY OPTIMIZE VOLTAGE?

A. Voltage optimization is accomplished by "flattening" a feeder line's voltage profile - or, in other words, narrowing the bandwidth of the voltage from the head-end of the feeder to the tail-end in concert with capacitors and other voltage regulating devices (discussed below) for voltage support. In the proposed IVVO model, voltage will be monitored along the feeder and at select end points (rather than only at the substation), allowing the head-end voltage to be significantly lower at most times.

Voltage optimization (i.e., managing the overall voltage profile of the feeder) will reduce demand and energy consumption while still ensuring that voltage levels are adequate for providing safe and reliable power to customers at all points along the distribution feeders, including the end of the feeders. IVVO will also reduce the electrical losses on the distribution system.

Q. WHAT WILL BE THE PHYSICAL COMPONENTS OF IVVO?

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

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

Q. PLEASE DESCRIBE THE CAPACITORS.

A. Electric loads like motors require two types of power to operate: active and reactive power. Distribution line capacitors provide local static VAr support or reactive power. By doing so, they help to limit both voltage drop and line losses across the distribution system. Capacitors are currently switched on and off based only on local conditions. The Company will continue to use its existing capacitor banks and will install new capacitors as part of this project. There will typically be three to six capacitors installed per feeder.

Q. PLEASE DESCRIBE THE SVCS.

A. The SVCs are electronic secondary capacitors that will provide fast, variable voltage support to help stabilize and regulate the voltage. Aside from the pilot program (discussed above), these devices will be a new technology introduced to Public Service's distribution system. Each device will be 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 60-90 second time delay. These devices will provide dynamic voltage response for load, and will be located closer to customers or nearer the edge of the grid than the Company's existing capacitors. The devices' capabilities will enhance the system's ability to respond to the variability of renewable DERs such as solar facilities and intermittent distributed resources. The Company will strategically place approximately 4,350 SVC devices along feeders that need additional voltage support.

Q. PLEASE DESCRIBE THE VOLTAGE SENSING DEVICES.

A. IVVO requires end-of-line voltage sensing to monitor the voltage and ensure it is compliant with American National Standards Institute ("ANSI") Standard C84.1. The Company intends to use AMI meters as sensors to provide near real-time voltage sensing.

Q. PLEASE DESCRIBE THE LOAD TAP CHANGERS.

A. Substation transformers equipped with LTCs will enable 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

Q. HOW IVVO WILL INTERACT WITH THE OTHER COMPONENTS OF THE AGIS INITIATIVE?

A. As mentioned above, advanced meters will act as the voltage sensor device and collect voltage information at each service point, which will be transmitted back to the ADMS through the FAN. ADMS will take the inputs from these devices that make up IVVO and compute the most efficient way for the system to operate and respond to changes. IVVO, through ADMS, will implement automated activities such as opening and closing of capacitors, and sending new settings to LTCs and SVCs. ADMS will also compute the most efficient way for the system to operate based on both manual switching and FLISR (e.g., for both maintenance and outages). The LTC control devices will take direction from ADMS, which will make decisions based on knowledge about the entire system, rather than only about voltage at the local bus. As a centralized system, ADMS will be able to control the distribution devices to work in unison and dynamically react to an increasingly complex system in a safe, efficient, and reliable manner.

E. Fault Location Isolation and Service Restoration ("FLISR") and Fault Location Prediction ("FLP")

Q. WHAT ARE FLISR AND FLP?

A. As mentioned above, FLISR stands for Fault Location Isolation and Service Restoration. FLISR involves deploying automated switching devices with the objective of decreasing the duration and number of customers affected by any individual outage. FLISR can noticeably reduce the amount of time customers will experience outages from faults, which I discuss in more detail below. It can also improve utility performance metrics such as system average interruption duration index (“SAIDI”) and the system average interruption frequency index (“SAIFI”).

Fault Location Prediction, or FLP, is a subset advanced 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 the fault.

Q. WHY IS PUBLIC SERVICE IMPLEMENTING FLISR AND FLP?

A. The Company is implementing FLISR because it will continue to improve reliability for our customers. FLISR is a technology that will allow the Company to understand when an event occurred and allow the Company to reconfigure the system more quickly than we are able to today, in most cases. This advanced application reduces the number of customers that suffer an outage for a prolonged period of time in the event of a fault.

FLP provides the Company with information that predicts the location of the fault. This allows the Company to respond to outages more efficiently and improve reliability.

Q. WERE FLISR AND FLP APPROVED IN THE GRID CPCN PROCEEDING?

A. No. FLISR and FLP are components of AGIS that the Company is implementing through the ordinary course of business.

Q. CAN YOU DESCRIBE IN MORE DETAIL A FAULT AND FAULT CURRENT?

A. Yes. Faults are either temporary or permanent. A permanent fault is one where permanent damage is done to the system and a sustained outage (i.e., 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 (i.e., less than five minutes). Causes of temporary faults include lightning, conductors slapping in the wind, and tree branches that fall across conductors and then fall or burn off.

When there is a fault—either temporary or permanent—the current or fault current is several to many times larger in magnitude than the current that normally flows due to load. The general profile for fault current is based on the distance from the substation (fault current is generally highest at the substation, decreasing as the location is further from the substation), type of fault (e.g., line-ground fault, three-phase fault), system voltage, and conductor type and size.

Q. WHY DOES PUBLIC SERVICE NEED THIS ADVANCED APPLICATION?

A. Today, Public Service has an average of 1,745 customers on each feeder. Because of the Company's current lack of visibility into the conditions on the distribution system feeders, when a fault occurs Public Service generally relies on calls from customers to inform the Company of the problem. Once customers have reported an outage in a given area, Public Service operators dispatch crews to patrol the area where they believe the fault occurred, based on the information gathered from the calls. Crews then proceed to isolate the fault and manually close switches to restore service to customers affected by the fault. The average time to restore a feeder-level fault is 68.3 minutes. Such a fault affects all customers on that feeder (1,745 on average).

Q. DOES FLISR OPERATE FOR ALL OUTAGE EVENTS?

A. No, FLISR devices will operate for outages that occur on the distribution mainline. Outages that occur on laterals will benefit from fault location prediction information and outages that occur on the secondary system will benefit from the proposed deployment of AMI meters. Although mainline outages only account for 3 percent of distribution outage events, today they account for over 30 percent of the distribution SAIDI.

Q. ARE THERE CURRENTLY DEVICES ON PUBLIC SERVICE'S DISTRIBUTION SYSTEM TO ASSIST IN FAULT ISOLATION AND SERVICE RESTORATION?

A. Yes. Public Service currently has small automation programs existing across its distribution system. In general, reclosers and sectionalizers are used to limit potential impacts of faults. Reclosers are tuned to operate in tandem with existing fuses or sectionalizers. They act as circuit breakers and are able to interrupt a fault event, meaning the recloser opens and the customers downstream of the recloser experience an outage. This is comparable to a household ground fault circuit interrupter ("GFCI") that opens when it detects a fault or issue, only affecting the devices downstream of the fault or issue, and not opening the breaker in a household breaker panel. Reclosers can also try to close a circuit (that has opened due to the fault) a certain number of times (to clear a temporary fault) before de-energizing all customers downstream. If successful, the process ensures that all customers upstream of the recloser would not experience any interruption of service. In addition, the reclosers will measure line current during faults (fault current) and report that data to ADMS. This will allow for not only identification of the type of fault that occurred, but also the identification of line sections where the fault may have occurred.

Sectionalizers are tuned so they de-energize downstream customers during a breaker or recloser-reclose cycle. This allows upstream customers to only experience a momentary interruption of service rather than a sustained outage.

However, without a centralized management scheme (such as ADMS) these devices cannot automatically restore customers located outside the fault zone.

Q. WHAT WILL BE THE COMPONENTS OF FLISR AND FLP?

A. There will be four principal components of FLISR:

- Reclosers;
- Automated overhead switches;
- Automated switch cabinets; and
- Substation Relaying.

There will be two main components to FLP:

- Power sensors; and
- Substation Relaying.

Q. WHAT ARE RECLOSERS?

A. Reclosers will be pole-mounted remote supervisory reclosing and switching devices. The Company currently has reclosers on the distribution system. The new devices will perform the functions of existing reclosers as described above. The devices will also be able to interrupt a fault event and will be able to report fault current to ADMS, which 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 exist, 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.

Q. WHAT IS AN AUTOMATED OVERHEAD SWITCH?

A. Switches are overhead remote supervisory sectionalizing and 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 would sense the loss of voltage and open, isolating the fault. However, unlike a recloser, the overhead switches will not have the capability of reclosing to determine whether there is a permanent fault. Instead, overhead switches rely on the feeder breakers for the reclosing functionality.

Although automated overhead switches lack the reclosing functionality, they utilize a compact form factor that makes them a better choice for space-constrained locations compared to reclosers.

Q. WHAT ARE AUTOMATED SWITCH CABINETS?

A. Automated switch cabinets are pad mounted sectionalizing and switching devices. They are motor-operated, remote-controlled devices that are expected to be utilized for underground feeder installations. They will perform functions similar to the automated overhead switches for underground feeders.

Q. HOW WILL FLISR FUNCTIONALITY IMPROVE THE CURRENT SITUATION?

A. FLISR components (described above) will divide the distribution feeders approximately into thirds with generally fewer than 1,000 customers in each section, with intelligent switches in place to tie each of those sections to another feeder. Existing reclosers and intelligent devices will be integrated into the FLISR scheme. If an existing device is in the correct location to employ FLISR functionality, this will obviate the need for a new device. Other existing devices will enhance FLISR's capabilities by enabling greater granularity in switching arrangements through having more precise voltage, current, and power information.

Once a feeder is enabled with FLISR, the system—in coordination with ADMS and FAN functionality—will automatically restore service to two-thirds of the customers on a feeder (or 1,163 customers on average) within minutes of the fault, and the other one-third of customers on the feeder (or 582 customers on average) may experience shorter service restoration times than the average of 68.3 minutes today due to the availability of more precise information regarding the location of the fault. Today, finding a fault location can involve patrolling the length of the entire feeder without knowledge of the general location. FLP will provide the general location of the faulted section reducing the area needed to be patrolled and will in many cases allow for shorter outage durations.

Q. CAN YOU DESCRIBE IN MORE DETAIL HOW FLISR OPERATES?

A. Yes, in the event of a fault, the FLISR protective devices will reclose or sectionalize the feeder as they currently do to isolate the fault. Once this occurs, data will be sent from those intelligent field devices to ADMS. ADMS will automatically run the FLISR application, which will locate the device closest to the fault and generate a switching plan to restore service to other customers, taking into account 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 is expected to take 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.

Q. CAN YOU DESCRIBE IN MORE DETAIL HOW FLP OPERATES AND HOW IT WILL IMPROVE DISTRIBUTION GRID PERFORMANCE?

A. Yes, Public Service is proposing to install up to two sets of three-phase advanced line power sensors along each feeder targeted for FLP deployment. One set will be installed on the feeder side of the substation, and another set could be installed down the line. Existing remote fault indicators and new intelligent device telemetry will be incorporated into the FLP deployment. If an existing device is in the correct location to employ FLP functionality, this will obviate the need for a new device. Other existing devices will enhance FLP's capabilities by providing additional data to improve FLP algorithm performance.

Feeders enabled only with FLP will operate in a slightly different manner from FLISR-enabled feeders. Should a fault occur, FLP devices upstream of the fault will capture an event occurring and will communicate relevant measurements during the fault (such as current, voltage, indication) to ADMS. ADMS will compare these measurements to the impedance model and will generate expected fault locations. It will then notify the operator of these locations (with a level of certainty for each location), and the operator will dispatch a crew directly to the expected faulted section (as opposed to having the patrol the entire feeder line, as in the current situation) to isolate the faulted section. This process is expected to reduce the patrol time per fault by providing a general location of the faulted section and reducing the area needed to be patrolled.

Q. WILL FLISR AND FLP MAKE USE OF AMI METERS?

A. Yes, indirectly. FLP 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. HOW WILL FLISR AND THE SENSING DEVICES INTERACT WITH ADMS?

A. As described above, ADMS will have an impedance model of the Public Service distribution system. Real-time current, voltage, and status data will be used to run load flow and state estimation applications on that model, providing awareness of system conditions for that feeder and surrounding feeders.

ADMS will provide for remote monitoring and control of FLISR and FLP devices. When a fault occurs on a FLISR- or FLP-enabled feeder, any device that is exposed to the fault will send a signal to ADMS notifying the system of the event. Devices that are capable will also send fault current during the event. ADMS will use both of sets of data, comparing fault current data against the impedance model to generate an expected fault location. If that feeder is FLISR-enabled, ADMS will generate a switching plan to isolate the faulted section based on system conditions, and will issue commands to field devices on the feeder and adjacent feeders so that non-faulted sections can be automatically restored.

Q. CAN YOU PROVIDE A COMPARISON TO A COMMON HOUSEHOLD SITUATION?

A. Yes, as a comparison, most strings of Christmas lights will not function at all if any one of the lights has a problem. Identifying the problematic light that causes the entire strand not to function requires testing each individual light. However, on a string of hypothetical “smart” Christmas lights, equipped with a centralized controller (comparable to ADMS) that communicates with each individual light, the centralized controller would use the data communicated to it by each of the lights to predict the location of the problematic light(s) to within a small set of lights. This is comparable to FLP. Once the lights' centralized controller isolated the small set of lights with the problem light, it would engage a switch that would allow the remaining lights to continue to work properly while the problem light is replaced. This is comparable to FLISR functionality.

F. Geospatial Information System ("GIS")

Q. WHAT IS THE GIS EFFORT?

A. 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. ADMS will use that information to maintain the as-operated electrical model and advanced applications. While the Company complies with the necessary rules and regulations in the recording of its assets, historically it has not been required to track the level of detail that ADMS will require in order to operate effectively. Therefore, the Company needs to review all of its physical asset records to ensure that the information available complies with the necessary level of detail needed for ADMS.

Q. HOW WILL THE COMPANY ASSESS THE LEVEL OF GIS DATA NEEDED IN ORDER TO EFFICIENTLY OPERATE ADMS?

A. The Company has entered in to a Technology Partnering Agreement with the National Renewable Energy Laboratory ("NREL") to have them assist the Company in analyzing the specific GIS data needed to enable the functionality in ADMS. As a member of the Department of Energy sponsored ADMS "Testbed", a consortium of national laboratories, NREL has the ability to assist the Company in this effort because it maintains demonstration laboratory that will allow the Company to model how ADMS will interact with various levels of data. This partnership which will also include Schneider Electric, the provider of the ADMS platform, creates cost savings for the Company and customers because it will allow the Company to efficiently collect the necessary amount of data to operate the system and achieve the Company's desired results. It also helps validate that the level of effort that we plan to undertake is appropriate.

A third party will complete the work of collecting the data. The Company has engaged in an RFP and selected two vendors to demonstrate their capabilities for this data collection effort. The Company will analyze the results provided by the vendors to determine which vendor should be awarded the contract. The Company hopes to award a contract in late 2017 or early 2018.

Q. WAS UPDATING THE COMPANY'S GIS RECORDS ONE OF THE AGIS PROGRAMS PART OF THE GRID CPCN PROCEEDING?

A. No. Updating the Company's GIS records is a component of AGIS that the Company is implementing through the ordinary course of business.

III. OVERALL AGIS IMPLEMENTATION

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

A. In this Section of my Direct Testimony I discuss the deployment schedule for the foundational components of AGIS that occurs between 2016 through 2022, consistent with the AGIS CPCN Settlement described by Company witness Ms. Jackson. I also provide the overall (total) capital and O&M costs of the AGIS initiative included in the MYP. Then I describe the anticipated work the Distribution Business Area will undertake in each year for each foundation component of AGIS for the MYP period, and provide a breakdown of the subset of AGIS costs related specifically to Distribution.

A. Overall Deployment Timeline

Q. WHEN WILL THE AGIS COMPONENTS BE DEPLOYED?

A. During the initial stages of the deployment of the AGIS programs, all of the programs will be deployed concurrently. ADMS and the FAN are the two foundational programs that are required to implement FLISR, FLP, and IVVO. Without ADMS, the field devices would operate in a similar manner to how they operate today, based on local conditions and with little awareness of the rest of the system. Without the FAN, the field devices would not have a means to communicate with ADMS and their head-end systems and similarly would operate in the same manner to how they operate today.

For ADMS, Public Service began the design and implementation of this program in the second quarter of 2016. Because ADMS is a foundational system that will control the advanced applications, ADMS is a critical path that must be functional upon deployment of the field devices.

The FLISR and FLP devices are on a nine-year deployment schedule that began in early 2017. The deployment will be prioritized by the historical reliability performance of the feeders, starting with the worst performing feeders. Deployment of devices will be in clusters of three-to-five feeders to gain the operational and reliability benefits in a localized area. Upon ADMS being operational, the FLISR devices will be commissioned into ADMS and the full functionality of FLISR will be enabled.

Implementation of IVVO is on a five-year deployment schedule to begin in 2017. The deployment will be prioritized by consideration of demand and energy, whether feeder lines and associated facilities are underground or overhead, and the location of existing capacitors. The areas with the greatest demand and energy will be prioritized first as they offer the greatest opportunity for demand and energy savings; the areas with largest amount of overhead feeders will be prioritized as installing devices on an overhead system is easier and more cost effective; and locations with existing capacitors that can be utilized will receive higher priority for participation. Deployment of devices will be on feeders grouped by substation to gain the efficiency benefits in a localized area. Upon ADMS being operational, the IVVO devices will be commissioned into ADMS and the full functionality of IVVO will be enabled.

Another key integration is between the ADMS system and the GIS system. Ensuring that the data specific to physical assets is current, validated and actionable to the prudent level of detail is critical to the success of the ADMS system and the distribution system. Distribution will be leading the data gathering and validation process as well as ensuring the update process for data is well-defined, automated to a prudent level and maintained over time as changes are made to the physical assets in the distribution system.

Q. IS THIS TIMELINE CONSISTENT WITH THE AGIS CPCN SETTLEMENT?

A. Yes. The Settlement likewise contemplated IVVO implementation commencing in 2017 and continuing through 2022. AMI deployment will begin in calendar year 2020 and will continue through 2024. The associated components of the FAN will be implemented in conjunction with the IVVO and AMI deployments.

Q. CAN YOU PROVIDE A CHART SHOWING THE OVERALL IMPLEMENTATION TIMELINE FOR THE FOUNDATIONAL AGIS PROJECTS DURING 2017 AND THE YEARS OF THE PROPOSED MYP (2018-2021)?

A. The table below provides a high-level overview of the deployment timelines for each major program in the AGIS initiative that is consistent with the AGIS CPCN Settlement.

Figure JDL-D-4

PROGRAM	DEPLOYMENT TIMELINE
ADMS	Planning: Ongoing Installation: Detailed design 2016-2017 System implementation 2017-2019
AMI	Planning: 2016-2018 Request for Proposal (“RFP”) issued in 2016 Vendor and contractor award for AMI mesh network and Head End anticipated in 3rd quarter of 2017 Anticipated AMI Meter RFP to be issued Q4 2018 Anticipated installation of first AMI meter 2019 Install 95% of AMI meters by end of 2023.
rtuFAN	Planning: Ongoing WiMAX and backhaul infrastructure 2016-2019 WiSUN (mesh network) implementation 2018- 2021
IVVO	Planning: Ongoing Installation: Anticipated 2017-2022
FLISR	Planning: Ongoing Installation: 2017-2025
GIS	2017-2022

B. Overall AGIS Costs for HTY and MYP

Q. WHAT ARE THE TOTAL CAPITAL COSTS ANTICIPATED FOR THE AGIS INITIATIVE INCLUDED IN THE COMPANY’S RATE CASE FILING?

A. The Company anticipates the following Total Company Electric costs for AGIS, including both Distribution and Business Systems components and overall governance and planning:

Table JDL-D-3
AGIS CAPITAL EXPENDITURES
Public Service (Total Company Electric)
(Dollars in Millions) [3]

Asset Class	AGIS Name	2016	2017	2018	2019	2020	2021
In CPCN	AMIe	1.0	28.2	30.3	36.3	58.1	65.7
	FAN		4.6	10.4	12.7	10.0	.3
	IVVO	.1	4.5	29.0	29.9	28.3	27.5
Not in CPCN	ADMS/GIS	4.0	18.3	22.7	9.6	7.8	9.1
	FAN	7.5	17.6	17.6	17.7	.8	.7
	FLISR/FLP	1.8	3.2	6.4	6.3	7.1	13.9
	Adv Grid/Other			5.1	8.9	10.6	15.6
Total Public Service Electric		14.4	76.3	121.5	121.4	122.8	132.9

I provide the primary support for the data collection/GIS portion of the ADMS, whereas Company witness Mr. Harkness supports the IT components.

* Company witness Mr. Harkness provides the primary budget support for the FAN.

+ Company witness Mr. Harkness provides the primary support for AMI integration and head end support, while I provide primary support for the AMI meters themselves.

Q. WHAT ARE THE TOTAL O&M COSTS ANTICIPATED FOR THE AGIS INITIATIVE INCLUDED IN THE COMPANY'S RATE CASE FILING?

A. The Company anticipates the following Total Company Electric O&M costs for AGIS, including both Distribution and Business Systems components and overall governance and planning:

[3] Differences due to rounding.

Table JDL-D-4
AGIS O&M BY YEAR
Public Service (Total Company Electric)
(Dollars in Millions) [4]

Asset Class	AGIS Name	2016	2017	2018	2019	2020	2021
In CPCN	AMIe		.8	1.8	2.4	5.6	6.7
	FAN		.3	1.2	2.6	4.1	5.0
	IVVO		.7	1.4	1.4	1.9	2.7
Not in CPCN	ADMS/GIS		.4	1.0	1.6	2.5	2.8
	FAN		1.8	3.2	4.5	4.7	4.8
	FLISR/FLP		.5	.8	.9	1.2	1.8
	Adv Grid/Other		.1	.3	.6	.6	.6
Total Public Service Electric			4.5	9.6	14.0	20.6	24.3

I provide the primary support for the data collection/GIS portion of the ADMS, whereas Company witness Mr. Harkness supports the IT components.

* Company witness Mr. Harkness provides the primary budget support for the FAN.

+ Company witness Mr. Harkness provides the primary support for AMI integration and head end support, while I provide primary support for the AMI meters themselves.

Q. HOW DO THESE COSTS COMPARE TO THE AGIS CPCN SETTLEMENT ON AMI?

A. The Company's current anticipated deployment costs are consistent with the settlement amounts identified by Ms. Jackson. However, as also consistent with the Settlement, the Company's projected costs include an additional $8.7 million

[4] Differences due to rounding.

dollar cost for the implementation of an AMI network that includes home area network ("HAN") capabilities. In developing the estimated costs for the Grid CPCN Projects, the Company did not include costs related to Home Area Network ("HAN") capabilities. As part of the AGIS CPCN Settlement it was agreed that the Company will install meters that incorporate HAN hardware and if doing so resulted in a cost increase, that increase would be afforded the same presumption of prudence as the Grid CPCN Projects costs. The vendor the Company selected to provide the AMI network provided HAN capabilities at an additional cost of $5.51 per meter.

Q. HOW DO THE COMPANY'S PROJECTED COSTS COMPARE TO THE AGIS CPCN SETTLEMENT ON IVVO?

A. The Company's projected IVVO implementation costs have not changed from the settlement amount.

C. AGIS Controls and Governance

Q. IS THE COMPANY ALSO INSTITUTING CONTROLS TO ENSURE THE IMPLEMENTATION OF AGIS PROJECTS IS CONDUCTED PRUDENTLY AND MONEY IS SPENT WISELY?

A. Yes. The Company has established processes to ensure a careful and thoughtful plan for the AGIS project development and implementation, and will also further supplement those processes as appropriate for each aspect of implementation.

Q. WHAT ARE THE KEY ASPECTS OF THE DISTRIBUTION BUSINESS AREA'S PROCESS TO ENSURE SUCCESS AND PRUDENT SPEND RELATED TO THE AGIS PROJECTS?

A. To ensure success and prudent spend related to the AGIS Projects, the Company has taken and will continue to take the following steps: Engage in benchmarking with peer utilities in the industry; leverage industry leading technology experts; utilize key business partners in robust sourcing processes; established formal internal governance structure that includes senior business leadership executives; established rigid decision processes and financial governance including rigorous project change request and approval processes; and is in the process of selecting an initiative level business management consultant to further support the overall governance and management of the projects.

The Company also established a contingency associated with the AGIS projects, included in its costs presented in this proceeding, which is prudent to present an anticipated cost level that is achievable. However, use of the contingency is closely managed and subject to internal approvals. Company witness Mr. Harkness discusses the contingency in more detail.

Q. HOW DOES THE COMPANY UTILIZE THESE OR OTHER PROCESSES TO ENSURE IT IS GETTING GOOD VALUE FOR AGIS DOLLARS SPENT ON CUSTOMERS' BEHALF?

A. Each of the activities the Company has taken is for the purpose of ensuring good value is delivered for the customer, although each addresses a different aspect of the program. By benchmarking with industry peers, the Company develops a strong understanding of the benefits and potential issues that can be encountered when implementing these types of programs. Learning as much as possible from the industry in the scope and design phases of the projects helps the Company plan and address potential issues appropriately, thereby helping to ensure plans are prudent. The engagement of industry experts such as EPRI, NREL, ICF International and others provides a similar measure of prudency.

These consultants' participation in the development of these programs helps the Company avoid mistakes, and results in a process to vet design decisions by providing input on the Company's assumptions regarding benefits and costs. They also ensure the right questions are asked of vendors in the sourcing process by supporting the development of thoughtful and detailed requests for information or proposals. The Company is utilizing robust sourcing processes in which the business area experts and the Company's sourcing professional partner to ensure the materials, services contacts and vendor procurements needed to deliver the AGIS projects are done in an open and ethical manner that provides the most effective sourcing decisions.

Q. HAS THE COMPANY ALSO IMPLEMENTED A DEFINED OVERALL GOVERNANCE STRUCTURE?

A. A robust governance structure and the associated governance processes are also critical to delivering the benefits and values of the AGIS Projects. To this end the Company has established a very strong governance structure that engages key business leaders in all aspects of the program's delivery. Senior Vice Presidents from the business areas of Distribution, Business Systems, Customer Care, Customer Solutions, Finance and Enterprise Transformation Office provide guidance through their roles on the AGIS Integration Council. These executives report to the AGIS executive sponsors, the Executive Vice President of Operations and the Executive Vice President, Group President Utilities and Corporate Services.

Within the program, the Company has established rigorous written procedures for both program management and financial governance. These procedures set appropriate approval levels for all aspects of project decisions from design to financial approvals. Of particular importance is the establishment of rules governing changes in scope or financial decisions above the base estimates provided in this proceeding where all project change requests must be documented and approved by the appropriate levels of management in the Company and within the established governance structure.

Q. HOW ELSE IS THE COMPANY WORKING TO ENSURE A ROBUST IMPLEMENTATION PROCESS?

A. Finally, the Company is planning on utilizing an industry leading management consultant with specific expertise in the areas of technology and program management to support and supplement the Company's own expertise in these areas and to supply additional expertise in areas where the Company may be lacking in-depth experience. This engagement of third party strategic partner will also ensure that the AGIS program is delivered cost effectively and achieves the desired benefits for the customer.

Q. HOW WILL THE COMPANY SUPPORT ITS AGIS COSTS – WHETHER CPCN PROJECT COSTS OR ORDINARY COURSE PROJECT COSTS – THROUGH THE REMAINDER OF THIS TESTIMONY AND OTHER COMPANY DIRECT TESTIMONY?

A. Earlier in my Direct Testimony I explained the origin of the AGIS CPCN projects and costs, particularly in relation to the AGIS CPCN Settlement. In the remainder of my testimony, I will walk through Distribution's work to budget for and implement the AGIS Projects and explain why it is appropriate to carry out each of the IT components of the AGIS initiative in the manner planned by the Company. While I provide overall support for the AGIS projects, Business Systems has primary responsibility for the ADMS IT components, the FAN, and integration of AMI (but not the meters themselves). I provide additional budgetary and implementation data for the AMI meters, the Advanced Field

Applications, the GIS data collection effort for ADMS, and additional elements of the AGIS implementation process including Program and Change Management efforts. Company witness Mr. David C. Harkness provides the primary support for an AGIS component (such as ADMS, the FAN, and AMI integration/head end support).

Q. CAN YOU PROVIDE A ROADMAP IDENTIFYING THE COMPONENTS OF AGIS WHERE YOU PROVIDE THE BUDGET DEVELOPMENT SUPPORT, VERSUS THE COMPONENTS DISCUSSED BY MR. LEE?

A. Yes. Mr. Harkness and I support the AGIS components as follows:

Table JDL-D-5

AGIS Foundational Project	**Component**	**Witness**
ADMS		
	System Development	Harkness
	GIS Data Collection	Lee
AMI		
	Meters and Implementation	Lee
	Head end application	Harkness
	IT integration	Harkness
FAN		
	WiMAX/WiSUN	Harkness
Advanced Applications		
	IVVO	Lee
	FLISR	Lee
	FLP	Lee

IV. DISTRIBUTION'S AGIS ACTIVITIES

Q. WHAT TYPES OF DISTRIBUTION CAPITAL COSTS WILL THE COMPANY INCUR TO IMPLEMENT THE AGIS PROJECTS?

A. The types of AGIS distribution capital costs the Company expects to incur include those capital costs required make capital modifications to equipment in distribution substations and located at various points on the electric distribution system generally discussed as make ready work, the capital costs to collect and build the GIS data additions required to operate ADMS, and the capital cost of installing additional equipment on the distribution system for IVVO, FLSIR and FLP, and the capital costs to install AMI meters. The types of costs incurred in performing these activities include but are not limited to labor, contractor and vendor services, transportation, material and stores expenses, permitting, traffic control, restoration, disposal costs, etc. These costs are illustrated in the capital additions as shown in Attachment JDL-2 to my Direct Testimony.

Q. WHAT ARE THE PROJECTED DISTRIBUTION CAPITAL COSTS OF AGIS IMPLEMENTATION DURING THE MYP?

A. The Distribution AGIS capital costs anticipated during the MYP are as follows. Company witness Ms. Deborah Blair presents the total revenue requirements associated with AGIS costs.

Table JDL-D-6
AGIS DISTRIBUTION CAPITAL EXPENDITURES
Public Service (Total Company Electric)
(Dollars in Millions)[5]

Asset Class	AGIS Name	2016	2017	2018	2019	2020	2021
In CPCN	AMIe	.5	1.6	3.1	7.8	29.0	61.2
	FAN		.5	1.3	1.6	1.4	.2
	IVVO	.1	3.3	21.0	24.4	22.8	23.3
Not in CPCN	ADMS/GIS	.5	3.0	8.5	7.5	7.8	9.1
	FAN	.1	.7	.8	.8	.3	.2
	FLISR/FLP	1.8	2.9	5.6	5.6	6.2	12.2
	Adv Grid/Other	0	0	3.6	8.2	7.2	5.5
Total Public Service Electric		2.8	12.0	43.8	55.9	74.6	111.7

Table JDL-D-7
AGIS DISTRIBUTION CAPITAL ADDITIONS
Public Service (Total Company Electric)
(Dollars in Millions) [6]

Asset Class	AGIS Name	2016	2017	2018	2019	2020	2021
In CPCN	AMIe		2.5	3.0	7.4	27.7	58.5
	FAN				3.3	1.3	.2
	IVVO		2.0	12.4	19.9	20.8	22.3
Not in CPCN	ADMS		3.4	8.4	7.5	7.8	9.0
	FAN				2.3	.3	.2
	FLISR	2.0	3.2	5.3	5.4	6.0	11.4
	Adv Grid/Other			3.1	7.5	7.4	6.6
Total Public Service Electric		2.0	11.2	32.1	53.3	71.2	108.2

Q. WHAT TYPES OF DISTRIBUTION O&M COSTS WILL THE COMPANY INCUR TO IMPLEMENT THE AGIS PROJECTS?

A. The types of O&M costs the Company expects to incur for AGIS include those typically associated with construction and O&M activities on the electric

[5] Differences due to rounding.
[6] Differences due to rounding.

distribution grid such as, but not limited to, labor, contract vendor, materials, transportation, permitting, restoration, and other services. During the construction and deployment of the AGIS field devices, O&M costs will be incurred because some aspects of the work will be on existing facilities that must be rebuilt or otherwise modified. Once deployed, expenses will be incurred to operate and maintain the installed devices in the normal course of business. I provide a breakout of these costs by project in my Direct Testimony.

Q. WHAT ARE THE PROJECTED DISTRIBUTION O&M COSTS OF AGIS IMPLEMENTATION DURING THE MYP?

A. The Distribution AGIS costs anticipated during the MYP are as follows, starting with the 2016 HTY.

Table JDL-D-8
AGIS Distribution Operating and Maintenance
Public Service (Total Company Electric)
(Dollars in Millions) [7]

Asset Class	AGIS Name	2016	2017	2018	2019	2020	2021
In CPCN	AMIe		.1	1.0	.7	2.6	4.2
	FAN		.1	.3	.3	.3	.1
	IVVO		.7	1.3	1.3	1.8	2.5
Not in CPCN	ADMS/GIS		.4	.8	.7	.5	.5
	FAN		.3	.4	.4	.1	.1
	FLISR/FLP		.2	.4	.6	.8	1.3
	Adv Grid/Other		.1	.2	.6	.5	.2
Total Public Service Electric			1.9	4.4	4.7	6.6	8.9

[7] Differences due to rounding.

V. INDIVIDUAL AGIS COMPONENT IMPLEMENTATION

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

A. In this section of my Direct Testimony I discuss the work that the Distribution Business Area will be undertaking in order to implement the foundational components of the Company's AGIS initiative. At a high level the work falls into four primary categories which are 1) installing field devices (meters, IVVO, FLISR, FLP), 2) data collection (ADMS/GIS), 3) determining appropriate business processes to manage the system, and 4) determining employees' roles and responsibilities in implementing and operating the new programs that are part of the AGIS initiative.

The last two categories I identified (3 and 4) are both part of Program and Change Management to ensure a successful implementation. Change Management is a systematic approach to effectively executing and managing fundamental organization changes, such as the way an electric utility effects an overall change to the distribution grid, like the AGIS initiative. Program management is an organizational effort designed to coordinate project management tasks necessary to incorporate the AGIS initiative into the current distribution system.

Below I will walk through each foundational component of AGIS and describe the specific work that the Distribution Business Area will do for that component. I also address additional work that the Company expects to undertake with respect to its substations in order to further support AGIS deployment.

A. ADMS/GIS

Q. WHAT WORK WILL THE DISTRIBUTION BUSINESS AREA UNDERTAKE TO IMPLEMENT THE ADMS PROJECT?

A. In order to implement the ADMS Project, the Distribution Business Area will own three aspects of the work that needs to be done. First, the GIS data collection effort can itself be divided into two components. One component is collecting data that will validate the physical characteristics of the current system. The other component is collecting the additional data that defines the electrical characteristics necessary to enable the ADMS model. The second category of work will be implementation of select intelligent field devices in order to test ADMS and ensure it has the necessary operating information.

Third, all components of AGIS will have Program and Change Management efforts. I discuss the work that will be done related to Program and Change Management in Section V.E below. The remaining ADMS work is conducted by Business Systems, and discussed by Company witness Mr. Harkness.

Q. WHAT WORK WILL THE DISTRIBUTION BUSINESS AREA COMPLETE REGARDING THE GIS DATA COLLECTION EFFORT TO ENABLE THE ADMS MODEL?

A. The Company will be validating the information we already have on the physical characteristics of the system. Since the ADMS is dependent on a robust dataset, the Distribution Business Area will leverage system and data knowledge and confirm the accuracy and completeness of the electric distribution grid model. This is accomplished by verifying the information contained in the corporate GIS via the performance of a physical data verification and capture effort with the goal of determining the level of readiness to support the ADMS application. We will also ensure the representations of customer load profiles and generation are accurate to meet the needs of advanced applications. Finally, we will use supervisory control and data acquisition ("SCADA") development for new device configuration requirements and alignment with current SCADA systems.

Q. CAN YOU PLEASE PROVIDE SOME EXAMPLES OF THE DATA THE DISTRIBUTION BUSINESS AREA WILL COLLECT?

A. Yes. Examples include the size of wiring, the size and location of equipment such as transformers, switches, poles, phasing and connectivity, and device control settings. This process validates the various data attributes contained in the corporate GIS system. As a result, the physical plant versus the electrically connected model are reflective of one another.

Q. CAN YOU PLEASE PROVIDE FURTHER EXPLANATION REGARDING THE FIELD DEVICES NEEDED TO IMPLEMENT ADMS?

A. Yes. In order to ensure that ADMS is operating efficiently and effectively the Company must complete end to end testing of the system and that cannot be done without field devices to gather the information that is needed for ADMS to operate and demonstrate it functions appropriately. As a result, some intelligent field devices will be implemented early for purposes of this testing. These devices are not temporary and will be used as part of the intelligent field device deployment. ADMS processes the information provided by these devices in near real-time and then uses the information in its application algorithms. ADMS then sends control commands to the advanced applications to effect the necessary change in power flow on the grid. As I discuss below, the cost of these devices will be included in the Distribution ADMS budget rather than the field devices budget since they will be used initially for testing purposes.

Q. WHAT WORK WILL THE DISTRIBUTION BUSINESS AREA COMPLETE TO TEST THE ADMS SYSTEM?

A. As discussed above, ADMS provides the electric distribution system with awareness and intelligence through the use of advanced applications. By implementing these devices for testing, the Distribution Business Area will be able to provide and validate use cases and test cases so we can ensure the software performs consistently with our needs for managing the electric distribution grid. We will also use this testing to develop and organize the skillsets necessary to configure and maintain ADMS performance with the substations and advanced applications. We will also participate in software testing to validate the software works to manage the electric distribution grid and deliver the application performance required to meet corporate commitments.

Q. CAN YOU BREAK DOWN THE WORK DISTRIBUTION WILL UNDERTAKE IN EACH YEAR OF THE MYP TO SUPPORT ADMS IMPLEMENTATION?

A. Yes. During the MYP, Distribution will undertake the following activities to implement ADMS:

2017:

- Data collection and formatting of all substation and field data required for system acceptance and testing
- Begin change management activities
- No planned in-servicing for ADMS components in 2017 is anticipated.

2018:

- Detailed unit, system and end-to-end testing of the ADMS solution as well as testing of all interfaces
- Continued data collection and formatting of all substation and field data required for system acceptance and testing
- Network model build completion
- Preparing for go-live and operational status in 2019.
- No planned in-servicing for ADMS components in 2018 is anticipated.

2019:

- Production roll out of the ADMS system
- Full in-servicing for ADMS components in 2019 is anticipated.

2020:

- Continued build out and refinement of the network model and data collection.

2021:

- Production support.

Q. PLEASE PROVIDE AN OVERVIEW OF THE INITIAL STEPS TO DEVELOPING THE GIS BUDGET FOR ADMS.

A. In order to create a project budget the Company has engaged in the following scoping activities:

- A gap analysis was conducted to determine the information currently available in the Company's GIS data model and what additional information is needed for ADMS to run successfully.
- Identification of changes required to the GIS data model to support ADMS.
- Identification of data that is to be captured from other sources (such as substation equipment databases) and how this will be provided to ADMS.
- Assessment of the quality of data currently held in the GIS and external sources and determine if 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 ADDITIONAL DETAIL REGARDING DEVELOPMENT OF THE ADMS BUDGET?

A. Yes. In general, the processes used to develop the Distribution Business Area portion of the ADMS budget was the same for both Distribution and Business Systems. Prior to beginning the sourcing process, in 2013 a cross functional team began identifying and visiting United States utilities that had either implemented or were in the process of implementing 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.

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 to ensure contract terms and deliverables were reasonable and appropriate due to ICG’s detailed industry knowledge of ADMS. Following contract negotiations, the Company and the successful vendor, Schneider Electric, began detailed design of the project in 2016 and completed the design in April of 2017. Based on this extensive effort, detailed budgets were developed and updated in June of 2016.

Q. WHAT ARE THE PRIMARY DISTRIBUTION ELEMENTS OF THE ADMS CAPITAL BUDGET?

A. The primary components of the ADMS budget are: (1) field audit of distribution pole data and data collection, (2) substation data collection and loading, and (3) contingencies for each component as set forth in Attachment JDL - 3 to my Direct Testimony.

Q. HOW DID THE DISTRIBUTION BUSINESS AREA DERIVE THE BUDGET FOR FIELD AUDIT OF DISTRIBUTION POLE DATA AND DATA COLLECTION, AND SUBSTATION DATA COLLECTION AND LOADING?

A. Two vendors (Cyient and Ramtech) participated in a data collection pilot effort in 2017. Their RFP responses provided expected costs for data collection by pole and substation. Xcel Energy used those per unit costs and extrapolated them using greater Public Service system information.

Q. HOW DID THE DISTRIBUTION BUSINESS AREA DEVELOP THE CONTINGENCIES FOR THE TWO BUDGETS DISCUSSED IMMEDIATELY ABOVE?

A. Because the data collection pilot was still in progress during budget development, an approximately 40 percent contingency was applied to the capital budget to account for potential uncertainties that may arise during the pilot.

Q. WHAT ARE THE PRIMARY COMPONENTS FOR THE ADMS O&M BUDGET?

A. The primary components of the ADMS O&M budget are: (1) labor, (2) training and communications, and (3) contingencies for each component as set forth in Attachment JDL - 3 to my Direct Testimony.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE BUDGET FOR LABOR?

A. We concluded that an additional engineering resource will be required for data maintenance and support beginning once the ADMS goes live in 2019, continuing through the end of the GIS project ($125,000 per year). As the system and its associated data needs expand in future years after ADMS goes live, another part time (30 percent) engineer will be required beginning in 2020.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE BUDGET FOR TRAINING AND COMMUNICATIONS?

A. The Company estimated that an additional training resource ($100,000 per year) will be required once the ADMS goes live in 2019, continuing through the end of the GIS project.

Q. HOW DID DISTRIBUTION OPERATIONS DEVELOP THE CONTINGENCIES FOR THE TWO BUDGETS DISCUSSED IMMEDIATELY ABOVE?

A. There is a high level of uncertainty as to how much work will be required for maintenance, support, and training related to the ADMS initiative. As a result, a higher contingency amount was applied to the budget (2/3, or approximately 67 percent).

Q. WHY IS THE DISTRIBUTION GIS COMPONENT OF THE ADMS BUDGET REASONABLE FOR CUSTOMERS TO SUPPORT?

A. 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 must be enhanced. The calculations will drive the operation of IVVO, FLISR, and as a means of tracking the FAN assets. Thus, this budget is a reasonable and necessary expense to enable the capabilities, which in turn provide the customer benefits. These include but are not limited to, the ability to enable customers to monitor and effectuate changes in their usage to manage their energy bills. This dynamic, customer-driven demand response ("DR") not only creates economic benefit for individual customers but also places significant downward pressure on regional electricity wholesale capacity and energy prices supporting larger region-wide economic and social benefits. Thus, GIS is a key enabler in supporting programs targeted at taking customers to a future where Demand Side Management (DSM) programs, focused on both energy efficiency and conservation and DR, are enabled by new technology investments that best meet customer lifestyles, behaviors, and electricity needs.

Further, the Company has gone through an extensive process to select an ADMS vendor that will be able to deliver the overall business requirements that have been determined as necessary to provide the capabilities that are necessary to operate a modern electric distribution grid. ADMS is not only a foundation tool, it is a critical part –the "engine" – of the overall package of tools necessary to deliver reliability energy efficiency measures and to enable the integration of increasing quantities of distributed energy resources without compromising reliability and power quality. Finally, the budgets for ADMS were also developed using this extensive process in which information was collected from other utilities, industry experts, consultants and a rigorous sourcing process.

B. AMI

Q. WHAT WORK WILL DISTRIBUTION OPERATIONS UNDERTAKE TO IMPLEMENT AMI?

A. In order to implement AMI, the Distribution Business Area will need to work with Business Systems to select an AMI Head-end and Network vendor and a separate AMI meter vendor, and to manage the logistics for AMI installation and removal of existing AMR meters. I provide an overview of the AMI development and the AMI meter vendor selection and budgeting; Company witness Mr. Harkness discusses AMI head-end and integration development.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROCESS FOR DEVELOPING THE AMI BUDGET.

A. The Company developed a budget for the overall AMI project through a combination of internal estimated costs and indicative costs from a Request for Information (RFx) sent to four AMI vendors in January of 2016 prior to issuing its RFPs in July of 2016. The RFx was intended to seek pricing information, but not necessarily formal bids, to help inform our planning and budgeting for AGIS projects at early stages of the project. Meter costs and AMI Vendor Project Management used in our modeling were derived from the averages of the vendors that responded to the RFx. Meter installation costs are a combination of vendor supplied pricing from the RFx and internal Company costs. Company witness Mr. Harkness describes how the Company used the same RFx to inform the AMI integration and head-end budgets. The results of the RFP, once received and analyzed, were utilized to confirm the costs previously used by the Company to prepare its estimates. The vendors responding to the RFP did not change their proposed pricing from those submitted in the RFx, which provides greater support that our cost projections are reasonable.

Q. PLEASE DESCRIBE THE RFx PROCESS IN MORE DETAIL.

A. A cross functional team of employees from multiple business areas developed an RFx related to AMI, FAN, and distribution automation. The business and IT areas that were represented on the team included Meter Performance and Standards, Sourcing Services, Distribution Engineering, Business Solutions, Customer Care, Telecommunications Engineering, and Enterprise Architecture. As part of the RFx, potential vendors were asked detailed technical questions regarding each of their individual AMI technology, including but not limited to the following topics:

- The technical standards their products are built to;
- Explanation of their standards-based philosophy and vision;

- Specific technical detail related to AMI, the FAN communication and distribution automation functions;
- The compatibility of their product with other components in the AGIS initiative; and
- Pricing information on meters and associated installation costs, FAN devices, head-end applications, project management and other support, and licensing costs.

The internal development team identified earlier in this answer evaluated the responses, and the Company used some of the information from the RFx for inputs in the Company's budget, such as AMI meters, residential meter installation services, head-end application and its associated annual recurring fee, and vendor professional services, which include project management, training, and network design.

Q. WHY IS THE COMPANY SELECTING SEPARATE VENDORS FOR THE AMI HEAD-END AND NETWORK VERSUS THE METER ITSELF?

A. Last year the Company issued a combined RFP that contemplated a single vendor for both the AMI head-end and network and the advanced meter. After evaluating the RFPs, the Company believes utilizing separate vendors will result in securing the best aspects of both components. The Company also believes that negotiating these components separately may result in lower overall costs, and any delay in meter vendor selection will ensure the Company and customers secure the latest available technology. With that said, it is important to note that the decision to select separate vendors and delay AMI meter selection will not delay the AGIS CPCN Settlement deployment timeline and the implementation of the AGIS initiative.

Q. WHAT IS THE CURRENT STATUS OF THE SELECTION OF AN AMI HEAD-END AND NETWORK VENDOR?

A. At this time, the Company has down-selected to a single AMI head-end and communication network vendor. We are currently engaged in contract negotiations with that vendor. While Business Systems is leading this effort, the Distribution Business Area continues to be an integral a part of the negotiations – including for the provision of HAN as part of the AGIS CPCN Settlement discussed in Section III above.

Q. WHAT IS THE CURRENT STATUS OF SELECTING THE AMI METER VENDOR?

A. A meter RFP will be issued to select one or more AMI meter vendors. This RFP is scheduled to be released to meter vendors by the Company when the negotiations with the down-selected AMI provider has been completed and the agreement is publicly announced. Responding bidders will participate in qualification testing between the fourth quarter of 2017 and approximately the third quarter of 2018.

After the Company evaluates the RFP bids and the results of the qualification testing, the Company may choose to split the AMI meter award to more than one vendor to achieve best pricing and quality across the various meter types. If the AMI meter award is split between multiple vendors it will not delay the deployment agreed to in the AGIS CPCN Settlement or the overall AGIS initiative.

Q. CAN YOU DESCRIBE THE WORK DISTRIBUTION WILL COMPLETE TO SUPPORT AMI IMPLEMENTATION DURING EACH YEAR OF THE MYP?

A. Yes. Distribution will complete the following activities to implement AMI:

2017:

- Participate in contract awards (from RFP) for system integration
- Participate in contract awards (from RFP) for network vendor to support Wi-SUN
- Initial design and planning processes initiated
- Begin qualification testing of various AMI meters as part of the AMI meter RFP process
- Begin process of for detailed business processes development – “as is” and “as to be” business processes
- Start change management efforts
- No planned in-servicing for AMI components in 2017 is anticipated.

2018:

- Detailed meter installation planning processes
- Complete AMI meter testing qualification
- Negotiate and complete contracts for meter deployments
- Continue work on business process development

- No planned in-servicing for AMI components in 2018 is anticipated.

2019:

- Build and testing of initial capabilities of the AMI solution
- Initial rollout of the 13,000 meters to support IVVO
- Establish cross-docking facilities for supporting meter deployment
- Refine customer communication plans to support mass meter rollout.

2020:

- Contract and program management
- Deployment of 175,000 meters
- Removal, retirement and disposal of replaced AMR meters
- Operational support for new meter installations as part of the full rollout of AMI meters
- Review prudency of HAN (home area network) and Green Button support as identified in the CPCN.

2021:

- Deployment of 570,000 meters
- Removal, retirement and disposal of replaced AMR meters.

Q. WHAT ARE THE PRIMARY COMPONENTS FOR THE DISTRIBUTION AMI CAPITAL BUDGET?

A. The primary components of the AMI capital budget are: (1) meters, (2) meter installation, (3) vendor project management, (4) AMI Operations, (5) contingencies for each component; and Change Management, as set forth in

Attachment JDL - 4 to my Direct Testimony. Change Management is a portion of each project's budget, and discussed separately in Section V.E of my Testimony. Lastly, the AMI budget includes HAN cost estimates, consistent with the AGIS CPCN Settlement.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE ITS CAPITAL BUDGET FOR THE AMI METER COSTS?

A. The budget for the meter costs was developed from the information provided from each vendor from the RFx for residential and commercial type meters. Costs were separated into two categories, residential and commercial. The total price of each category was averaged by the number of meters in that category, and the results of each category from each vendor were then averaged to arrive at an overall estimated unit cost. The resulting meter per unit cost of $107.55 used in the budget includes estimated taxes and associated material, meter seals, and meter rings. With the additional cost of $5.51 per meter for the HAN capabilities included, the final per meter cost used to derive the budget was $113.06. These costs are incorporated into Attachment JDL-4 to my Direct Testimony.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE ITS CAPITAL BUDGET FOR AMI METER INSTALLATION?

A. The budget for meter installation was developed from the average cost provided from the RFx responding vendors, which was $17 per meter. Only two of the three vendors provided estimated pricing for commercial meter installation services. When evaluating the costs provided for commercial meters, the Company determined that the vendor information did not provide sufficient detail to determine if the vendors met the Company's required installation procedures. As a result, a weighted average of the Company's present contractor installation costs for commercial meters were weighted proportionally to arrive at a per unit commercial meter installation cost of $34.51. A weighted average of residential and commercial meter installation cost of $18.08 per meter was used. These costs are incorporated into Attachment JDL-4 to my Direct Testimony.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE ITS CAPITAL BUDGET FOR AMI VENDOR PROJECT MANAGEMENT?

A. The budget for AMI vendor project management was developed from the average pricing provided by respondents to the RFx. In addition to project management, this cost estimate includes training, integration assistance, and system testing. These costs are incorporated into Attachment JDL-4 to my Direct Testimony.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE ITS CAPITAL BUDGET FOR AMI OPERATIONS RELATED TO INTERNAL AND EXTERNAL PERSONNEL?

A. Internal personnel include the roles and positions of AMI Analyst, Billing Analyst, Project Operations Manager, Meter Supervision, Meter Engineering, and Inventory Analyst. The budget for these positions was estimated using average internal wage scales for these positions and estimating when the roles would be needed to throughout the AMI deployment. External personnel include the roles of Billing Contractor, Scheduling Contractor, and Temporary Office Contractor. The budget for these positions was also estimated using average costs for these positions and estimating when the roles would be needed to throughout the AMI deployment. Additionally, external personnel costs include an Electrical Contractor and a General Repair Contractor. The budget for these is an estimate of costs that we may incur as a result of the Company needing to repair customer property that may be damaged during the meter exchange.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE CAPITAL BUDGET FOR CONTINGENCY COSTS FOR THE AMI METERS, METER INSTALLATION, VENDOR PROJECT MANAGEMENT AND AMI OPERATIONS?

A. The budget for the contingencies for the capital components of the AMI budget were developed because a final vendor has not yet been selected, costs associated with AMI implementation are the Company's best effort at accurate forecasting, and the Company believes the selected contingency is reasonable. Contingency amounts for meters (8 percent) and AMI vendor project management (15 percent) are based on the pricing ranges provided in the RFx vendor responses. The contingency for meter installation (10 percent) is based on installation options and procedures dependent on meter types.

Q. WHAT ARE THE PRIMARY COMPONENTS FOR THE DISTRIBUTION AMI O&M BUDGET?

A. The primary components of the AMI O&M budget are: (1) AMI Operations (internal and external personnel), (2) facility rental, (3) meter disposal, and (4) contingencies for each component as set forth in Attachment JDL - 4 to my Direct Testimony. Change Management, another component, is discussed later in my Direct Testimony.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE ITS O&M BUDGET FOR AMI OPERATIONS AS IT RELATES TO INTERNAL AND EXTERNAL PERSONNEL?

A. The budget for AMI Operations is based on costs associated with internal and external project personnel using typical Company wages and contractor costs at estimated wage scales. The O&M cost of resources within AMI Operations was derived by estimating a 98%:2% capital versus O&M cost split.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE ITS O&M BUDGET FOR FACILITY RENTALS?

A. The budget for facility rentals is needed for warehouse space to support the staging of new meters and processing of removed meters. The estimate for this cost is based on internal estimates of 35,000 square feet at a cost of $28 per spare foot per year for the deployment period. It also includes $230,000 for modifications, IT needs, and office furniture. These costs are included in Attachment JDL-4 to my Direct Testimony.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE ITS O&M BUDGET FOR METER DISPOSAL?

A. The budget for the costs for meter disposal are estimates that include sorting, removal of batteries as needed, and separation of encoder receiver transmitter ("ERT") modules from the AMR meters.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE ITS BUDGET FOR CONTINGENCY COSTS FOR THE AMI O&M BUDGET?

A. As noted in Attachment JDL-4, the Company developed a 10 percent contingency budget for the O&M costs related to AMI operations and personnel. This contingency is low because of the knowledge that the Company has related to internal and external labor costs. With that said, the 10 percent contingency for these items is an estimate.

Q. WHY IS THE AMI BUDGET REASONABLE FOR CUSTOMERS TO SUPPORT?

A. AMI is a foundational component of AGIS. As discussed above, AGIS is a long-term strategic initiative to transform our electrical distribution business to enhance security, efficiency, and reliability, to safely integrate more distributed resources, and to enable improved customer products and services. The AMI budget put forward is reasonable in enabling technologies that improve customer products and services.

C. FAN

Q. WHAT WORK WILL DISTRIBUTION OPERATIONS UNDERTAKE TO INTEGRATE THE FAN?

A. From a Distribution Business Area perspective, the FAN it is largely make ready work for the devices to be placed on the distribution system. For example, if a pole needs to be modified or replaced in order to support a particular piece of communications hardware, the Distribution Business Area will be responsible for that. We will also be responsible for physically installing the hardware at each location.

Q. WHAT BUSINESS UNIT WAS RESPONSIBLE FOR DEVELOPING THE BUDGET FOR FAN?

A. Business Systems was primarily responsible for developing the budget for the FAN, and any make ready work that the Distribution Business Area will complete is embedded in that budget. Therefore, Company witness Mr. Harkness discusses most of the FAN budget. The costs that are supported by Distribution are shown in Attachment JDL-5.

Q. CAN YOU IDENTIFY THE WORK DISTRIBUTION WILL COMPLETE EACH YEAR OF THE MYP TO SUPPORT THE FAN IMPLEMENTATION?

A. Yes. Distribution will undertake the following activities in each year of the MYP to support FAN implementation:

2017:

- Make ready work to support 2017 FAN equipment installations
- Planning for make ready work to support 2018 installations.

2018:

- Complete make ready work as needed for 2018 FAN equipment installations
- Planning for 2019 make ready work to support FAN equipment installations
- Process and change management activities continue
- Distribution capital make ready work completed in 2018 will be in-serviced.

2019:

- Complete make ready work as needed for 2019 FAN equipment installations
- Planning for 2020 make ready work to support FAN equipment installations
- Process and change management activities continue
- Distribution capital make ready work completed in 2019 will be in-serviced.

2020:

- Complete make ready work as needed for 2020 FAN equipment installations
- Support ongoing operations and maintenance
- Process and change management activities continue as fan moves from deployment to ongoing operations and maintenance

- Distribution capital make ready work completed in 2020 will be in-serviced.

2021:

- Support operations and maintenance of FAN devices in distribution substations and field device on the Distribution system

D. <u>Advanced Applications (IVVO, FLISR, FLP)</u>

Q. WHAT WORK WILL DISTRIBUTION OPERATIONS UNDERTAKE TO IMPLEMENT ADVANCED APPLICATIONS?

A. The Distribution Business Area will be responsible for the acquisition and installation of the physical devices that makeup the advanced applications. For IVVO this includes the installation of approximately 115 substation load tap changer controls, 1,100 capacitors, and approximately 4,500 low voltage static VAr compensators. For FLISR and FLP this includes installing approximately 900 feeder automation devices (reclosers and sectionalizers) and 350 advanced sensors, which are devices that monitor the distribution system and can provide advanced information on system disturbances. This work will be done in combination with internal labor and third party contractors.

The Distribution Business Area will also be responsible for the system analysis to determine the appropriate placement of the 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 an advanced application device to be placed on that pole or reconfiguring an underground cable so that a padmounted piece of equipment can interconnect with it. Company witness Mr. Harkness discusses Advanced Application implementation from the Business Systems perspective.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION REGARDING THE WORK DISTRIBUTION WILL COMPLETE DURING THE YEARS OF THE MYP TO IMPLEMENT THE ADVANCED APPLICATIONS?

A. Yes. Distribution will complete the following activities each year to implement IVVO, FLISR, and FLP:

2017:

- Initial planning and design for these advanced applications
- Deployment of approximately 60 FLISR feeder automation devices
- Deployment of approximately 80 IVVO medium voltage capacitor banks and 10 substation load tap changer control upgrades
- Begin process and change management activities
- Individual field devices will be in-serviced as they are installed.

2018:

- Detailed design for these advanced applications
- Deployment of approximately 75 FLISR feeder automation devices and 100 FLP sensors
- Deployment of approximately 300 IVVO medium voltage capacitor banks, 1000 low voltage static VAR compensators, and 20 substation load tap changer control upgrades
- Individual field devices will be in-serviced as they are installed.

2019:

- Detailed design for these advanced applications
- Deployment of approximately 80 FLISR feeder automation devices and 120 FLP sensors
- Deployment of approximately 350 IVVO medium voltage capacitor banks, 1500 low voltage static VAR compensators, and 30 substation load tap changer control upgrades
- IVVO and FLISR business system components (the applications) to be in-serviced for these advanced applications is planned for 2019. Associated field devices installed during the year will also be in-serviced.

2020:

- Continued support of IVVO and FLISR software capabilities
- Deployment of approximately 90 FLISR feeder automation devices and 120 FLP sensors
- Deployment of approximately 250 IVVO medium voltage capacitor banks, 1100 low voltage static VAR compensators, and 30 substation load tap changer control upgrades
- Individual field devices installed during the year will be in-serviced.

2021:

- Continued support of IVVO and FLISR software capabilities
- Deployment of approximately 170 FLISR feeder automation devices

- Deployment of approximately 200 IVVO medium voltage capacitor banks, 1000 low voltage static VAR compensators, and 25 substation load tap changer control upgrades
- Individual field devices installed during the year will be in-serviced.

Q. WAS DISTRIBUTION OPERATIONS PRIMARILY RESPONSIBLE FOR DEVELOPING THE BUDGET FOR ADVANCED APPLICATIONS?

A. Yes. Therefore I describe the budget development process for Advanced Applications in more detail.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROCESS FOR DEVELOPING THE ADVANCED APPLICATION BUDGET.

A. After the Company selected IVVO, FLISR and FLP for its advanced applications in the AGIS initiative, the Company developed its budget for these advanced applications by using data from historical installations of comparable devices, as well as pricing details from vendor quotations and pilot projects.

1. IVVO

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

A. The primary components of the IVVO capital budget include (1) device costs, (2) installation costs, (3) vendor project management, (4) labor, (5) device operations, (6) communication operations, and (7) contingency costs for the components of the IVVO capital budget. These are identified in Attachment JDL-6 to my Direct Testimony.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE CAPITAL BUDGET FOR THE IVVO DEVICE COSTS?

A. Previous construction projects across Xcel Energy provided the basis for primary capacitor bank costs. Substation engineering compiled estimate summaries for several different sites, and those were averaged to provide estimated substation costs. Finally, Xcel Energy had a pilot program testing SVC devices from Varentec, Inc. that began in 2013. Quotes provided from Varentec and work order charges during that pilot were used to estimate costs for that component.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE CAPITAL BUDGET FOR IVVO INSTALLATION COSTS?

A. Xcel Energy performed an analysis that estimated the required amount of VArs necessary to correct power factor to near unity on the feeders in the Denver metro area. This provided a total quantity of primary capacitor banks necessary for the deployment. Based on results of the Varentec pilot, estimates were also made as to the incremental benefit provided by a targeted deployment of those, which produced a quantity for SVC devices. Finally, the average estimated cost to upgrade substation LTCs was applied to the total fleet of substations in the Denver metro area, with adjustments made to account for other work which would naturally replace these (proactive or emergency transformer replacements, etc).

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE CAPITAL BUDGET FOR LABOR?

A. Previous completed projects were used to estimate labor hours required to install each component of the project.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE CAPITAL BUDGET FOR COMMUNICATION OPERATIONS?

A. Xcel Energy's standard pole mounted communications design provided the material costs used in the communication operations estimates.

Q. HOW DID DISTRIBUTION OPERATIONS DEVELOP THE CONTINGENCIES FOR THE IVVO CAPITAL BUDGETS THAT HAVE BEEN DISCUSSED?

A. Xcel Energy applied a 10 percent contingency to Distribution costs for IVVO. This is a much tighter contingency figure compared to the Business Systems contingency component, reflective of Distribution's spend component being mostly work with which the company has significant experience.

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE IVVO O&M BUDGET FOR ADVANCED APPLICATIONS?

A. The primary components of the IVVO O&M budget include (1) on-going device support, (2) device replacements, (3) on-going communications network costs, (4) training, and (5) contingency costs for the components of the IVVO O&M budget. These are identified in Attachment JDL-6 to my Direct Testimony.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE O&M BUDGET FOR THE ON-GOING IVVO DEVICE SUPPORT?

A. Labor estimates were provided by maintenance crews and engineers that work on similar equipment today.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE O&M BUDGET FOR IVVO DEVICE REPLACEMENTS?

A. Expected lifecycles and replacement costs were estimated for each major component within the SVCs and primary capacitor banks based on previous experience. These costs were tabulated (batteries are to be replaced every 5 years and cost $500) and averaged to arrive at a yearly cost.

Q. HOW DID DISTRIBUTION OPERATIONS DEVELOP THE O&M BUDGET FOR THE ON-GOING IVVO COMMUNICATIONS NETWORK COSTS?

A. Estimates were compiled based on previous equipment experience.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE O&M BUDGET FOR THE IVVO TRAINING?

A. Estimates were compiled for the amount of training required for each resource (1/2 day average per year) and the number of resources that would receive this training (10 new resources average per year), which was then averaged across the total count of expected devices.

Q. HOW DID DISTRIBUTION OPERATIONS DEVELOP THE CONTINGENCIES FOR THE IVVO O&M BUDGETS DISCUSSED IMMEDIATELY ABOVE?

A. Distribution applied a 10 percent contingency to the expected O&M costs.

2. FLISR and FLP

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE FLISR AND FLP CAPITAL BUDGET FOR ADVANCED APPLICATIONS?

A. The primary components of the FLISR and FLP capital budget include (1) device costs, (2) installation costs, (3) vendor project management, (4) labor, (5) device operations, (6) communication operations, (7) device replacements, and (8) contingency costs for the components of the FLISR and FLP capital budget. These are identified in Attachment JDL-7 to my Direct Testimony.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE CAPITAL BUDGET FOR THE FLISR AND FLP DEVICE COSTS?

A. Previous completed projects utilizing the FLISR equipment were used to develop expected capital and O&M costs for both overhead and pad mounted FLISR equipment. Xcel Energy had previously piloted FLP sensors from Tollgrade, Inc. and quotes from this work were used to develop estimates for FLP.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE CAPITAL BUDGET FOR FLISR AND FLP INSTALLATION COSTS?

A. Previous project labor costs were used to estimate FLISR installation costs. Labor costs during the Tollgrade pilot done in Xcel Energy’s other operating companies, Northern States Power and Southwestern Public Service, were used to estimate installation costs for FLP.

Q. HOW DID DISTRIBUTION OPERATIONS DEVELOP THE CAPITAL BUDGET FOR FLISR AND FLP VENDOR PROJECT MANAGEMENT?

A. Xcel Energy estimated a small quantity of external training required for FLISR devices, to account for any software or engineering training required for new resources (30 minutes per device). Quotes from the Tollgrade pilot project provided expected vendor costs related to training, management software and RTU licensing costs.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE CAPITAL BUDGET FOR FLISR AND FLP LABOR?

A. Previous deployment labor costs provided estimates for FLISR and FLP labor.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE CAPITAL BUDGET FOR FLISR AND FLP DEVICE OPERATIONS?

A. Previous deployments provided an estimate for FLISR and FLP device operations costs. An example of this work includes time required to operate switches to de-energize sections targeted for construction.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE CAPITAL BUDGET FOR FLISR AND FLP DEVICE REPLACEMENTS?

A. Distribution experiences a roughly 0.6 percent equipment failure rate. 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 accurately reflect those costs in the FLISR and FLP deployments.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE CAPITAL BUDGET FOR FLISR AND FLP COMMUNICATION OPERATIONS?

A. Labor estimates provided by communications engineering served as the basis for FLISR and FLP communications operations estimates.

Q. HOW DID DISTRIBUTION OPERATIONS DEVELOP THE CONTINGENCIES FOR THE IVVO CAPITAL BUDGETS DISCUSSED IMMEDIATELY ABOVE?

A. Distribution applied a 10 percent contingency to both capital and O&M costs for FLISR and FLP.

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE FLISR AND FLP O&M BUDGET FOR ADVANCED APPLICATIONS?

A. The primary components of the FLISR O&M budget include (1) on-going device support, (2) component replacements, (3) on-going communications network costs, (4) training, and (5) contingency costs for the components of the FLISR and FLP O&M budget. These are identified in Attachment JDL-7 to my Direct Testimony.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE O&M BUDGET FOR THE ON-GOING FLISR AND FLP DEVICE SUPPORT?

A. Labor estimates were provided by maintenance crews and engineers that work on similar equipment today.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE O&M BUDGET FOR FLISR AND FLP DEVICE REPLACEMENTS?

A. Expected lifecycles and replacement costs were estimated for each major component within the FLISR and FLP devices, based on previous experience. These costs were tabulated (batteries are to be replaced every 5 years and cost $500) and averaged to arrive at a yearly cost.

Q. HOW DID DISTRIBUTION OPERATIONS DEVELOP THE O&M BUDGET FOR THE ON-GOING FLISR AND FLP COMMUNICATIONS NETWORK COSTS?

A. Estimates were compiled based on previous equipment experience.

Q. HOW DID DISTRIBUTION OPERATIONS DERIVE THE O&M BUDGET FOR THE FLISR AND FLP TRAINING?

A. Estimates were compiled for the amount of training required for each resource (1/2 day average per year) and the amount of resources that would receive this training (10 new resources average per year), which was then averaged across the total count of expected devices.

Q. HOW DID DISTRIBUTION OPERATIONS DEVELOP THE CONTINGENCIES FOR THE FLISR AND FLP O&M BUDGETS DISCUSSED IMMEDIATELY ABOVE?

A. Distribution applied a 10 percent contingency to both FLISR and FLP O&M budgets, to reflect the relative familiarity with this equipment.

Q. WHY IS THE ADVANCED APPLICATION BUDGET REASONABLE FOR CUSTOMERS TO SUPPORT?

A. The service area for IVVO was chosen as the Denver metro area to encompass the majority of system load and customers, while also selecting system infrastructure that inherently reacts positively to IVVO. For example, the IVVO service area generally includes feeders that are shorter and have stronger interconnections to surrounding feeders and substations.

The deployment of IVVO was also crafted to minimize cost impacts. Substation load tap changer control upgrades are being designed such that their replacement impacts as few other substation components as possible. The majority of Distribution device costs are associated with medium voltage capacitor banks, which have a much lower incremental cost per Kilovolt-Amperes Reactive ("kVAr") compared to low voltage static VAr compensators. Existing capacitor banks also will be utilized as much as possible where they meet the technical requirements of IVVO. The addition of the low voltage static VAr compensators provides an appreciable benefit increase as well, and previous pilot projects in the PSCo region have shown very favorable results from these devices.

For the FLISR project, the deployments similarly target high load, high customer count feeders across PSCo. The Company's System Performance team used analytics to determine the appropriate deployment areas. System

Performance also investigated different telemetry options for FLP devices, producing cost and benefits projections for substation relay telemetry upgrades compared to advanced line sensor deployments. These projections indicated that line sensors provided nearly the same system value at a far lower cost.

E. Program and Change Management Supporting AGIS

Q. WHAT OTHER COSTS ARE INCLUDED IN THE IMPLEMENTATION OF THE FOUNDATIONAL COMPONENTS OF AGIS?

A. The Distribution Business Area will also be primarily responsible for the Program and Change Management work that will need to be done for each foundational AGIS component to ensure a successful implementation of the AGIS initiative. The work that the Distribution Business Area will undertake for these activities is nearly identical for each foundational component of AGIS. First, I will describe what Program and Change Management is and then I will describe the work that the Distribution Business Area will undertake to complete these activities.

Q. WHAT IS PROGRAM MANAGEMENT?

A. Program management is an organizational effort designed to coordinate project management tasks necessary to incorporate the AGIS initiative into the current distribution system. It 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, program management is needed due to the highly interrelated and interdependent nature of the many components of the AGIS initiative at the individual project level.

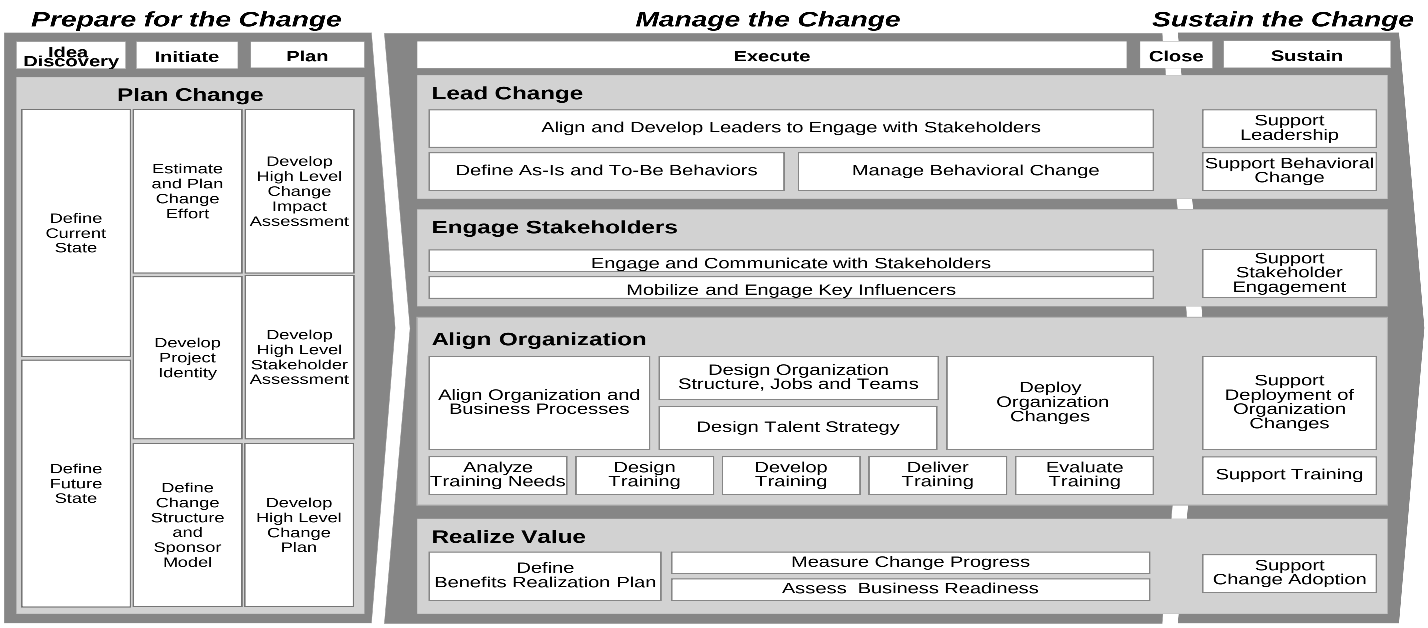
Q. PLEASE DESCRIBE THE COSTS ASSOCIATED WITH PROGRAM MANAGEMENT FOR THE AGIS INITIATIVE.

A. We have estimated the present value of program management costs for 2016-2021 to be approximately $18.8 million across the AGIS projects (both CPCN and non-CPCN). Approximately $17.6 million of that estimate is capital. These capital costs include engaging consultants and contractors throughout the development, deployment, and conclusion of the AGIS initiative. Approximately $1.2 million will be attributable to operations and maintenance ("O&M") expenses. These O&M costs include upper management review and strategic program oversight, as well as incremental corporate services obtained in direct support of the initiative.

Q. WHAT IS CHANGE MANAGEMENT?

A. Change management is a formal discipline that dates back to the 1980's. It is a systematic approach to effectively executing and managing fundamental organization changes, such as the way an electric utility effects an overall change to the distribution grid. The diagram below illustrates that the three main elements of Change Management – prepare, manage and sustain – each involve significant detailed analysis, action and documentation.

Table JDL-D-9 Change Management Diagram



Q. WHY IS CHANGE MANAGEMENT NEEDED FOR THE AGIS INITIATIVE?

A. 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 or entity that is affected by the implementation of the AGIS initiative. Public Service intends to engage a consultant that is experienced in developing such comprehensive plans for utilities.

Q. WHAT DOES A TYPICAL CHANGE MANAGEMENT PLAN OF THIS MAGNITUDE ENTAIL?

A. The Company will engage in three steps to facilitate the change management plan for the AGIS initiative. In order to prepare, the Company will engage in the first step of planning for the change. The second step is managing the change. Finally, in order to sustain the change the Company will engage in the third step of reinforcing the change.

Q. CAN YOU DESCRIBE THE WORK THAT DISTRIBUTION OPERATIONS WILL COMPLETE DURING THE FIRST STEP OF PLANNING FOR THE CHANGE?

A. Yes. This will take place in a series of workshops over the course of six months to one year. The first step in this phase is to identify the key process and people changes. This will be done through workshops where current processes will be mapped against future processes. Then process impact assessments will be completed. This will determine the precise number of employees and job functions that will be affected by each key process change. A key process change may impact more than 1,000 people or as few as ten or less people. The sum of this information is the change impact inventory that will drive the second step, which is how the change is managed.

Q. WHAT WORK WILL DISTRIBUTION OPERATIONS UNDERTAKE IN IN DEVELOPING THE SECOND STEP OF MANAGING THE CHANGE?

A. This step will begin at the end of the first step described above. There are several components to developing how the change is managed. In this phase, the Company uses the change management process to facilitate behavioral change, develop employee and stakeholder communications, identify changes to existing organizational structures, develop training, and develop readiness. This step will take several years to complete and it will be ongoing throughout the implementation of the AGIS initiative, which is expected to be 95 percent complete by the end of 2020. The step of managing the change must occur while the AGIS initiative is being implemented because the only way to determine how the AGIS initiative impacts stakeholders is through the real scenarios that are created through deployment.

For example, the Company cannot train an operator on how his system will be different until the system is designed. The additional piece is that change management will also engage the operator in the design process because that operator is best suited to provide the most valuable feedback regarding how the system he operates daily should be configured. The table below indicates the analysis that is done in developing each component of managing the change:

Table JDL-D-10 Change Management Analysis

Behavioral Change	Evaluate necessary behavioral changes due to the implementation of the AGIS initiative. For example, do the changes require more collaboration, more proactive employee and stakeholder engagement, or should data be used differently?
Communications	Evaluate the best means to teach employees and stakeholders why the change is being made. Ensure they are aware of the need and desire to make the change.
Organizational Structure	Evaluate whether the implementation of the AGIS initiative requires the Company to alter how business units are currently structured. Determine if new groups are needed within existing departments. If so, the new positions and the development of proper descriptions of required skills and competencies will be done in workshops, along with mapping employees to new roles.
Training	Develop and deliver training on the new processes, technology, and equipment.
Readiness	Develop surveys, focus groups and other methods to gather insight to use to evaluate if the Change Management Plan is resonating with employees and stakeholders.

Q. HOW DOES THE COMPANY ENSURE THAT THE CHANGES MADE ARE REINFORCED?

A. In order to ensure that the changes implemented as part of the AGIS initiative are sustained, the Company will engage in the third step in the change management plan, which is to reinforce the change. The Company will do this by ensuring people, processes, and organizations are in place to support the new way of working during and after the components of the AGIS initiative go live. Also, training will not be a one-time event, nor will it take place in a single format. As people move into new roles and new employees are hired, they will be trained on the new processes and technologies.

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

A. We have estimated change management costs for 2016-2021 to be approximately $27.6 million across all AGIS (both CPCN and non-CPCN) projects. Approximately $18.6 million of that estimate is capital. These capital costs include engaging consultants and contractors throughout the development, deployment and conclusion of the AGIS initiative. 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. Approximately $9.0 million will be attributable to O&M expenses. These O&M costs include upper management review and strategic program oversight, as well as incremental corporate services obtained in direct support of the initiative.

Q. ARE CHANGE MANAGEMENT COSTS REASONABLE?

A. Yes. The cost estimates for change management were developed independently for each component of the CPCN Projects. The change management cost for AMI is 3 percent of the total AMI cost. This percentage was benchmarked against and consistent with Ameren Illinois and First Energy Corporation, which installed AMI projects of a similar size. The Company's costs for IVVO and the FAN comprise 12 percent of the total cost of each component. The Company found these costs to be consistent with its own expertise in change management during its recent experience implementing an enterprise wide initiative involving the Company's new general ledger and work asset management systems discussed by Mr. Brossart. The difference in the percentages of costs attributed to AMI versus IVVO and the FAN is due to the fact that the change management activities that will take place for AMI, IVVO and the FAN are roughly equivalent. Therefore, the costs of change management for each component are roughly equivalent, but comprise a smaller percentage of the larger AMI budget.

Q. ARE PROGRAM MANAGEMENT COSTS REASONABLE?

A. Yes. The program management costs are 2.8 percent of the overall cost of the CPCN Projects. The Company determined the costs based on the need to build a program management team that will consist of approximately fifteen 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. The costs identified in my testimony are the ones that were allocated against the AGIS components included in the CPCN Projects.

F. AGIS Other: Substation Communications

Q. HOW DO SUBSTATION COMMUNICATIONS RELATE TO AGIS?

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 quickly impose traffic and up-time requirements exceeding the equipment's capacity. Thus the category for Substation Communications, while not characterized as new "Advanced Grid" in nature, is necessary and supportive of the Advanced Grid.

Q. DOES THE COMPANY ANTICIPATE THE NEED FOR ADDITIONAL INVESTMENTS IN SUBSTATIONS TO MAXIMIZE THE VALUE OF AGIS?

A. Yes. Experience has shown that when new capabilities are needed within substations, we often find existing equipment to be at capacity. For instance, when installing a new feeder there may be insufficient space available in the substation's Remote Terminal Unit ("RTU") to accommodate the new feeder. Installing new equipment for FLISR and IVVO places such an additional need at the RTU. Similarly, the substation battery may be near capacity and the addition of FAN equipment may necessitate an increase in size. Therefore we budgeted funds to remedy that deficiency at a percentage of our substations during the MYP. These amounts are included in the Adv Grid: Other/Supporting Technology Projects line items in Table JDL-D-3 earlier in my testimony, and capital expenditures and O&M costs are broken down in more detail in Attachment JDL-8 to my testimony.

Q. HOW WERE THE BUDGETS FOR THESE SUBSTATION COMMUNICATIONS NEEDS DEVELOPED?

A. Substation communication costs were developed based on our estimate that roughly two-thirds of the Public Service substation fleet will require modifications due to FAN, FLISR, and/or IVVO. These modifications are expected to primarily include work such as battery upgrades and remote terminal unit (“RTU”) replacements. The Company’s budget is based on the estimated subset of substations that will need this work, with costs for battery upgrades and RTU replacement based on the Company’s experience and work on other RTU/battery projects.

VI. INNOVATIVE CLEAN TECHNOLOGY PROJECTS

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

A. In this section of my Direct Testimony I discuss the ICT Projects that are part of the AGIS initiative, but are not considered to be a foundational component of AGIS. I provide the background and updates on the ICT projects, the associated settlement, and project implementation planning. While I note that the Company is seeking to amortize the capital additions, include the 2017 O&M in rates, and defer O&M for 2018 to 2021 to a future rate case, Company witness Ms. Blair (rather than myself) discusses the Company's proposed ratemaking treatment for the ICT Projects.

A. Background and Project Description

Q. PLEASE BRIEFLY DESCRIBE THE INNOVATIVE CLEAN TECHNOLOGY ("ICT") PROGRAM.

A. The overall ICT program is designed to provide a regulatory mechanism to demonstrate newly emerging technologies that are intended to further the development, deployment, and commercialization of new power generation and other technologies environmentally superior to technologies currently in use. In 2009, Public Service initiated Proceeding No. 09A-015E in which it sought approval of the ICT program and its first ICT project, a concentrating solar thermal power project at the Company's Cameo Generating Station site.

Q. HAS THE COMMISSION ESTABLISHED ANY ICT PROGRAM GUIDELINES?

A. Yes. In Proceeding No. 09A-105E, the Commission approved the overall ICT program and provided guidelines for future ICT project applications in Decision No. C09-0889, mailed on August 13, 2009. The Commission ordered that the Company file an application for approval of each proposed ICT project in the future.

Q. DID THE COMPANY FILE AN APPLICATION FOR APPROVAL OF THE ICT PROJECTS AT ISSUE IN THIS RATE CASE?

A. Yes. On October 29, 2015, the Company filed an application in Proceeding No. 15A-0847E ("Project Application") asking the Commission to approve two new ICT projects, the Panasonic Project and the Stapleton Project (the "ICT Projects" or the "Projects"). Both Projects involve the evaluation of energy storage technology installed on distribution feeders that have relatively high penetrations of distributed solar generation.

Q. WHAT IS THE COMPANY STUDYING THROUGH THESE ICT PROJECTS?

A. Over the next 10 years, the Company expects to learn how battery systems can mitigate the impacts of high distributed solar energy on a feeder and potentially increase distribution feeder ability to accommodate more solar energy than it can without these systems. As customer interest in PV systems increases, we may find that more feeders are reaching the tipping point where additional amounts of solar energy on the feeder could introduce voltage issues or other problems. We are also studying what other capabilities battery systems may have as additional value propositions to make the systems more cost-effective, such as providing energy arbitrage, DR, frequency response, and back-up power. We see battery systems playing a bigger role in a more modern grid and are learning how to integrate these devices with both our existing and planned systems, such as the ADMS implementation in AGIS.

Q. PLEASE DESCRIBE THE PANASONIC PROJECT IN MORE DETAIL.

The Panasonic Project is a partnership between Public Service and Panasonic Enterprise Solutions Company ("PESCO"), developed to test and demonstrate certain energy storage capabilities of a utility-scale battery in conjunction with a photovoltaic ("PV") solar system. The goal of the Panasonic Project is to test a number of the potential capabilities of such a battery energy storage system, including the opportunities for 1) mitigating voltage fluctuations on the distribution grid stemming from operation of grid-installed solar generation; 2) reducing system peak demand and demand on the feeder; 3) reducing energy costs; 4) enabling frequency response; and 5) providing backup or "microgrid" service.

The Panasonic Project consists of three primary components:

- A single 1 MW / 2MWh lithium ion battery energy storage system ("BESS") owned by Xcel Energy and installed on a commercial distribution feeder at the PESCO Denver facility;
- A single 1.3 MW solar installation on a carport adjacent to the PESCO facility. Xcel Energy owns the PV system and the City and County of

Denver ("CCOD")/Denver International Airport ("DIA") owns the carport; and

- Xcel Energy-owned switching and control systems used to operate the BESS and microgrid functionality.

The battery system is interconnected on the utility side and during normal operations it supports the grid through voltage management, peak demand reduction, energy arbitrage, and frequency response. For the first two years of the Panasonic Project, these scenarios will be operated as defined in the test plan filed with the Commission on May 9, 2016.

In the case of a grid outage, an islanding switch separates the battery system from the grid, and the battery system then provides power to PESCO's building. Based on the state of the charge of the BESS and any information PESCO may have on the length of the outage, PESCO will determine how to operate and prioritize the loads in its building. If the outage occurs during typical solar production hours, PESCO's rooftop PV system (which is a net-metered system owned and operated by PESCO and not part of ICT funding) will also provide power to the PESCO building, since the BESS can provide the necessary voltage support for the PV system. The BESS and PV system run independently of each other: the battery stores and discharges energy from the grid, and the Company-owned carport PV system generates energy that feeds to the grid.

The Panasonic Project will be installed for 10 years and operated in two phases: two years of testing and demonstration as described above, and eight years of operation at optimal settings (as established by the demonstrations). During the two-year demonstration period, the capabilities noted above will be tested and the performance of the system will be measured and monitored. After the demonstration is complete and the collected data analyzed, the battery will operate at its established optimal settings for the remaining eight years of its life. The PV system is expected to remain on the carport for an additional 10 years after the BESS is removed, but the Company may evaluate in the future whether to maintain the system longer.

Q. WHAT IS THE CURRENT STATUS OF THE PANASONIC PROJECT?

A. Full testing is expected to begin in September 2017, once the BESS is completely commissioned through certification that all its functions are operational and the system is able to perform each of the planned Project tests. The Company filed test plans for the Panasonic Project on May 9, 2016 and began implementation in earnest in October of 2016, when designs for the carport PV system and BESS were completed. Construction of the carport solar system began in December 2016 and the PV system was placed in service in March 2017. The BESS cleared factory acceptance testing at the fabrication factory in Texas in mid-February 2017 and arrived at the PESCO facility in early March 2017. As of July 2017, Construction is complete. Most of the system commissioning is complete, with the sole exception being full testing of the BESS in microgrid mode. This final test is expected to occur in August 2017, along with final punch list activities. Once commissioning is completed, full testing pursuant to the Company's May 9, 2016 Panasonic Project test plans can begin immediately.

Q. PLEASE DESCRIBE THE STAPLETON PROJECT IN MORE DETAIL.

A. The Stapleton Project is a pilot program designed to assess how battery storage could potentially be used to integrate higher amounts of PV solar energy on the distribution system. We are examining how battery systems can operate to mitigate the impacts of high amounts of solar energy on the feeder, reduce peak demand on the feeder, and reduce the marginal cost of energy by storing power at a lower cost of energy and discharging when energy costs are high.

The Stapleton Project involves installation of a series of batteries strategically placed on a residential feeder in the Stapleton neighborhood of Denver, an area experiencing high penetration of rooftop solar. Six batteries will be installed on the utility side of the distribution system, and six on the customer side of the meter. The Stapleton Project will be operated for 10 years in two phases. Once the systems are installed, testing will occur for two years to analyze system performance in the various operating modes and determine how they can provide the most value to the grid. After the two year demonstration period, the utility-sited batteries will continue to operate in the established optimal modes for their remaining eight years of life. Customers participating in the pilot have the option to continue to utilize the battery system after the two year testing period or have it removed.

Q. WHAT IS THE CURRENT STATUS OF THE STAPLETON PROJECT?

A. Stapleton Project testing is expected to begin in approximately November 2017 after final commissioning of both the utility-sited and customer-side systems. We selected vendors for both systems through an open request for proposals (“RFP”) process that included considering comment from ICT stakeholders. We issued the RFPs on June 6, 2016 and responses were due July 8, 2016.

The Company awarded the customer-side system contract to Sunverge Energy, Inc. and has entered into agreements with six (6) customers to participate in the pilot. As of August 2017, five (5)of the customer systems have been installed. The last location involved a customer selected for participation who later sold her home, which caused us to postpone this installation. We plan to approach the new homeowner for participation once the sale contract is finalized. After reviewing the vendor proposals for utility-sited systems in response to the June 2016 RFP, we held preliminary discussions with CCOD related to siting as we are planning to place some of the systems in the Company’s right of way (“ROW”). Conversations with CCOD established that the battery system sizing dimensions and proposed footprints as bid were larger than desired. We therefore asked vendors to come back with proposals for smaller systems. Based on the revised bids, we awarded the utility-sited battery systems contract to Northern Reliability, Inc.

Public Service filed the Stapleton Project test plans on March 29, 2017. Factory assembly of the Northern Reliability units is currently underway, with preliminary factory acceptance occurring in June 2017. Assembly of the Sunverge units is complete, and as discussed above, five (5)of the six (6) customer units have been installed. Project construction of the utility-sited battery systems is expected to begin in September 2017, with final system commissioning expected by November 2017 and testing to begin immediately.

B. ICT Settlement Agreement

Q. DID PUBLIC SERVICE ENTER INTO A SETTLEMENT AGREEMENT RELATED TO THE PANASONIC AND STAPLETON PROJECTS?

A. Yes. The Company settled with six (6) intervenors and the Commission approved the settlement agreement in Decision No. C16-0196, mailed March 8, 2016 ("ICT Settlement").

Q. DOES THE ICT SETTLEMENT SET FORTH TOTAL ESTIMATED COSTS FOR THE PANASONIC AND STAPLETON PROJECTS?

A. Yes. The total cost estimates set forth in the settlement were $6,720,000 for the Panasonic Project and $4,012,000 for the Stapleton Project. The ICT Settlement as approved by the Commission allows the Company to use deferred accounting of the capital expenditures for both ICT Projects.

Q. HAVE THE TOTAL COSTS FOR IMPLEMENTING THE ICT PROJECTS BEEN MODIFIED SINCE THE COMMISSION APPROVED THE ICT SETTLEMENT?

A. Yes, but not significantly, as the total costs for both ICT Projects are expected to fall within the respective estimates presented in the ICT Settlement. There have been certain changes to the scope of the ICT Projects which I discuss in the next section of my testimony, and some of those changes resulted in cost increases. The initial Panasonic Project estimate was $6,720,000 ($5,720,000 capital and $1,000,000 O&M), and total costs are currently projected to come in at $6,832,967. The ICT Settlement estimate for the Stapleton Project was $4,012,000 ($3,412,000 capital and $600,000 O&M), and we are expecting total Stapleton costs to come in at $3,236,153. The forecast budgets for both Projects, broken down between capital and O&M, are further detailed in Attachments JDL-9 and JDL-10 respectively.

Q. HAVE THE CAPITAL PROJECT COSTS CHANGED SINCE THE ICT SETTLEMENT?

A. Yes. The Panasonic Project capital costs have increased to $6,832,967. Capital costs for the Stapleton project have decreased to $3,236,153.

Q. HOW DOES THE ICT SETTLEMENT ADDRESS O&M COSTS?

A. The Commission-approved ICT Settlement allows for ongoing O&M expenses associated with the ICT Projects after testing begins to be recorded in separate deferred accounting mechanisms to seek recovery in future rate proceedings. At the time of the ICT Settlement, the estimated ongoing O&M was approximately $1,000,000 for the Panasonic Project and approximately $600,000 for the Stapleton Project.

Q. HAVE THE O&M COSTS FOR IMPLEMENTING THE ICT PROJECTS BEEN MODIFIED SINCE THE ICT SETTLEMENT?

A. Yes, both have decreased. The Panasonic Project O&M cost estimates have decreased to $543,079. The Stapleton Project O&M costs are forecasted to decrease to $244,759.

Q. DOES THE ICT SETTLEMENT ADDRESS REMOVAL COSTS FOR THE PROJECTS?

A. It does not. Removal costs are a necessary and expected part of any installation project, but the parties to the ICT Settlement did not make any specific stipulations regarding recovery of removal costs for the Panasonic or Stapleton Projects.

Q. DOES THE ICT SETTLEMENT ADDRESS ANY ADDITIONAL PROJECT TESTING?

A. Yes. The ICT Settlement states that Public Service will test advanced inverter technology either in the Stapleton Project or choose to present another ICT project which tests advanced inverter functionality. The Company is currently researching how to best undertake this effort, including possible Stapleton Project site partnerships with the Electric Power Research Institute (“EPRI”) and the National Renewable Energy Laboratory (“NREL”). In compliance with the ICT

Settlement, if we decide to incorporate the advanced inverter test into the Stapleton Project, we will request Commission authorization if doing so increases costs materially. If the Company instead determines a new ICT project is preferable for advanced inverter testing, we will solicit stakeholder feedback on the proposed project before filing an application for Commission approval**.**

C. ICT Projects Implementation

Q. HAVE THERE BEEN ANY SCOPE CHANGES TO THE ICT PROJECTS SINCE THE COMMISSION APPROVED THE ICT SETTLEMENT?

A. There have been no significant scope changes to the Panasonic Project. There are some changes to both the customer-sited and utility-sited aspects of the Stapleton Project. Regarding customer systems, we found through the RFP process that most vendors' battery systems have the capability to power a customer's home in the event of a power outage, and we thought it would be important to test and demonstrate this standard back-up power option. This scenario was not included in the original scope of the Stapleton Project, but after learning of the option and discussion with vendors, we decided to pursue it. Therefore, the scope of customer-side installation has changed in that battery vendors will install the customer system with the intent to power a portion of the customer's load during a grid outage.

There have been two changes to the scope of the utility-sited systems: reduced battery size and addition of a radial loop. First, as discussed above, we are using smaller battery sizes for all six systems due to space constraints.

Originally, we planned to have the batteries on either end of a radial half-loop sized to match the loop's entire reverse power flow, for a total of three loops being utilized. The smaller utility-sited battery sizes we will now be installing may not match the entire reverse power flow of the loop, but will match the reverse power flow of a half loop. We originally planned to have a set of utility-sited batteries serve each of the three radial loops chosen for the Stapleton Project but ran into siting issues with a system proposed to be located on private land, and will therefore move that battery system to a new fourth radial loop.

Q. WHAT IMPLEMENTATION WORK HAS BEEN COMPLETED ON THE PANASONIC PROJECT TO DATE?

A. Implementation work for the Panasonic Project falls into three categories: 1) installing equipment and interconnecting to the grid; 2) establishing communications and software integration across equipment and with the company's systems; and 3) commissioning equipment. Once these steps are complete, the ongoing efforts will be centered around collecting and analyzing data from the Project tests.

As of the date of this filing, all primary and ancillary equipment for the Project has been installed at the PESCO and CCOD/DIA facilities. This includes the BESS, the Company-owned carport PV system, and the switching and control systems used to operate the BESS and microgrid functionality. With one exception, all of the equipment has been commissioned (by ensuring all functions of a unit are working in isolation before full operation can begin) – the only remaining commissioning step is testing the BESS in full microgrid mode. The Project is interconnected to the distribution grid so the system is ready to perform its full functions, including isolating from the grid should there be an outage.

Q. WHAT PANASONIC PROJECT IMPLEMENTATION WORK REMAINS THROUGH THE LIFE OF THE PROJECT?

A. The sole remaining step before the Project can begin testing is the final commissioning of the BESS, confirming it functions properly in microgrid mode; we expect this to occur in September 2017 and full testing to commence immediately afterwards. Once that full testing begins, most of the ongoing work will be monitoring the installation and collecting data. The BESS and switching gear will be removed in approximately 2027, and the carport PV system in 2037. Public Service will determine the necessary steps and costs for equipment removal at that time and seek recovery after removal.

Q. INCLUDING THE SCOPE CHANGES YOU DISCUSS ABOVE, WHAT WORK HAS BEEN COMPLETED ON THE STAPLETON PROJECT TO DATE?

A. Steps for the Stapleton Project implementation include 1) selection of customer-side and utility-sited battery vendors; 2) installation of equipment and interconnection to the grid; and 3) commissioning of equipment. To date, we have awarded the battery contracts through a competitive solicitation process and installed four of the six customer-side batteries on Project participants' homes. Each of the remaining processes is currently underway as of the date of this filing.

Q. WHAT IMPLEMENTATION WORK REMAINS FOR THE STAPLETON PROJECT?

A. As of July 31, 2017, the majority of the Stapleton Project installation is still pending. Upcoming implementation steps include installing the two remaining customer-side batteries, installing all six utility-sited batteries once factory assembly is complete, commissioning of all 12 batteries, and interconnecting all batteries to the distribution grid. Once these steps are complete, which we expect to occur in approximately November 2017, remaining Project work will primarily focus on data collection.

As with the Panasonic Project, the Stapleton Project will be removed in approximately 2027. Removing the installation will require additional work, which the Company will establish at the time of removal and seek recovery of those costs after removal work is complete.

D. ICT Cost Projections and Management

Q. YOU NOTED ABOVE THAT THE COMPANY IS SEEKING TO AMORTIZE CAPITAL COSTS AND 2017 O&M COSTS, AND DEFER O&M COSTS FOR 2018 AND BEYOND. HOW WILL THE COMPANY HANDLE ICT PROJECT COSTS IT INCURS AFTER THE MYP?

A. Pursuant to the ICT Settlement approved by the Commission, the Company intends to seek recovery of ongoing O&M costs we incur in the periods between rate cases through the life of the Panasonic and Stapleton Projects. Public Service will bring any ongoing O&M costs not addressed in this current filing to the Commission in future rate cases until the ICT Project installations are removed and no longer generating O&M-related expenses. Company witness Ms. Blair describes how this proposal is implemented in her Direct Testimony.

Q. WHAT ARE THE KEY ASPECTS OF THE DISTRIBUTION OPERATIONS PROCESS USED TO ENSURE SUCCESS AND PRUDENT SPEND RELATED TO THE ICT PROJECTS?

A. Project success and prudent spend aspects include 1) establishing specifications, 2) streamlined project management, and 3) monitoring system performance.

First, it is important to make sure the battery system specifications at the outset are clear and precise. At the beginning of both the Panasonic and Stapleton Projects, we worked with EPRI to review the Project specifications we developed. We also utilized draft specifications prepared by Energy Storage Integration Council ("ESIC"), an industry working group facilitated by EPRI created to identify gaps and approaches for integration of energy storage, including applications of energy storage connected to utility distribution systems. We worked with EPRI to develop use cases for the Panasonic system and the Stapleton utility-sited systems to help ensure the battery systems were designed to operate the way we intended them to, and shared that information with our selected vendors.

On the project management side, we have and will continue to work closely across business systems, distribution operations, vendors, distribution engineering, and other key areas to make sure personnel fully understand Project requirements and management of timelines and budgets.

Finally, once testing begins, we will monitor battery performance to make sure that the systems continue to operate as intended and that they are not operated in a manner that causes excessive degradation of the battery systems.

Q. WHAT WILL THE COMPANY DO IF IT IDENTIFIES COST INCREASES OR CONCERNS IN THE IMPLEMENTATION OF THE ICT PROJECTS?

A. As is the Company's standard practice, we will take all prudent and available steps to keep the ICT Project budgets within the estimated costs. If, however, we determine that the recovery we are seeking in this rate case proceeding is not sufficient to cover the capital and/or O&M costs for the ICT Projects in their entirety, we will present the additional costs for recovery in a future rate case. Given that we will be seeking recovery of O&M costs incurred in the periods between rate cases through the life of the Projects, there is already a mechanism in place for demonstrating prudency of any unexpected cost increases.

Q. DO YOU BELIEVE IT IS APPROPRIATE TO INCLUDE THE CAPITAL COST ASSOCIATED WITH THE ICT PROJECTS IN RATES?

A. Yes, I do. The projects are being implemented and managed in a prudent manner, consistent with the ICT Settlement Agreement approved by the Commission.

VII. RELIABILITY

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

A. In this section of my Direct Testimony I discuss the Company's historic reliability and service quality performance and how that performance positively compares to both the Company's recent past performance, and to peers in the electric utility industry based on industry standard benchmark results. Further, I discuss the Company's expectations regarding future trends in electric utility reliability performance and how the AGIS programs will help continue to maintain the Company's reliability performance at levels that provide strong results for customers as compared to industry averages. These reliability goals reflect part of the potential value of the AGIS initiative.

Q. CAN YOU PROVIDE A HIGH-LEVEL OVERVIEW ON HOW PUBLIC SERVICE PROVIDES RELIABLE ELECTRIC SERVICE?

A. Public Service provides reliable service by designing the system to limit the number of outages and the number of customers impacted by an outage. When there is an outage or a major storm hits, we respond swiftly and effectively to restore power. Public Service continues to be a leader in terms of reliability performance consistently performing in the top quartile compared its peers and on average customers have electric service more than 99.9 percent of the time.

Q. HOW DOES THE COMPANY DETERMINE THAT IT IS PROVIDING RELIABLE SERVICE TO ITS CUSTOMERS?

A. The Distribution Business Area commits both capital and O&M investments to maintain reliable electric service. These generally either mitigate future outages, or improve our ability to limit any outages to the smallest number of customers for the shortest possible duration. The Company tracks reliability metrics and measures performance through benchmarking with other utilities. The Company also has a Quality of Service Plan ("QSP") in place with the Commission.

Q. WHAT RELIABILITY MEASUREMENTS ARE USED AS PART OF THE QSP?

A. The QSP has two types of measurements: system level and customer level. For the system level measurement, the QSP utilizes System Average Interruption Duration Index ("SAIDI") for a selected set of data. SAIDI is the average duration of interruptions customers experience during a year quantified in minutes. It is normalized data that focuses on performance of distribution lines only, and specifically excludes impacts due to Public Damage, properly planned outages, and outages caused by outages deliberately caused in the interest of public safety. Annual performance targets are defined based on historical performance within each region separately. There are performance penalties if any region does not meet its target for two years or more in a row. For the customer based measurements the QSP has monitoring and penalty structures for customers experiencing multiple outage events within a given time frame, and for customers experiencing outage events that last longer than 24 hours.

Q. WHAT HAS BEEN THE COMPANY'S PERFORMANCE RELATIVE TO THE QSP IN 2015 & 2016?

A. The Company has performed well in 2015 and 2016 relative to the QSP. For each the 9 QSP reporting regions, SAIDI penalties are paid if the region's Reliability Warning Threshold ("RWT") is exceeded 2 years in a row. No penalties were paid in 2015. In 2015, 5 of the 9 regions (Front Range, Greeley, High Plains, Mountain, and San Luis Valley) exceeded RWT. But none of the regions exceeded RWT in 2014. In 2016, only the Greeley region exceeded RWT, resulting in a penalty of $310,805.

For the customer based metric for customers experiencing multiple interruptions, penalties were paid in 2015 and 2016 to some of Public Service's approximately 1.4 million customers. The maximum penalty for Public Service is $1 million/year for this metric, with a $50 maximum paid to any customer. In 2015, Public Service paid $368,900 as $50 bill credits to 7,378 customers for exceeded the Electric Continuity Threshold ("ECT"). In 2016, $405,600 was paid to 8,112 customers.

For customers experiencing long interruptions, a $50 bill credit is paid anytime the Electric Restoration Threshold ("ERT") is exceeded. In 2015, 347 customers received penalty payment for a total of $17,350 in bill credits. In 2016, 80 customers exceeded the ERT with a total penalty of $4,000 paid by Public Service.

Q. HOW DOES THIS COMPARE TO THE LAST TIME THE COMPANY FILED A MULTI-YEAR RATE PLAN?

A. The last multi-year plan the Company reported the 2012-2013 QSP results. When comparing to the 2015-2016 QSP results the number of customers exceeding the ECT decreased by 9,034 customers representing an improvement of approximately 37 percent and the number of customers exceeding the ERT decreased by 112 customers representing an improvement of approximately 21 percent.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE QSP?

A. No, with the exception of requesting to extend the QSP as discussed by Company Witness Ms. Marci McKoane.

Q. HOW DOES THE COMPANY COMPARE TO ITS PEERS WITH RESPECT TO SAIDI PERFORMANCE?

A. The Company utilizes the IEEE Distribution Reliability Working Group large utility group benchmarking to compare its performance against similar sized electric utilities. The Company compares itself to other large utilities, those of over one million customers. The IEEE survey is voluntary; in 2016, 93 entries were received, of which 32 were included in the large utilities group.

The Company has consistently ranked in the 1st quartile or the top of the 2nd quartile even has overall industry reliability as continued to improve each year. Currently, Public Service ranks in the first quartile for 2016 with a SAIDI value of 86.5 minutes. The following table details the Company's rankings for the past 7 years:

Table JDL-D-11

IEEE DRWG Benchmarking (Large Utility Group) - SAIDI

	Quartile	Minutes
2016	1st	86.5
2015	1st	88.3
2014	1st	84.8
2013	2nd	93.9
2012	1st	93.2
2011	1st	95.1
2010	2nd	94.7

Q. DID THE COMPANY EVER EXPRESS CONCERN REGARDING ITS ABILITY TO CONTINUE TO MAINTAIN ITS RELIABILIT?

A. Yes. In my Direct Testimony in the AGIS CPCN proceeding, I stated that the Company currently ranks within the first quartile for SAIDI but is highly unlikely to maintain our position amongst our peers by 2020 without advancing the distribution grid. This is because industry expectations are becoming more stringent as technology for advanced grids develops. It is expected that by 2020 utilities will need a SAIDI of 84 minutes to achieve first quartile SAIDI status, and that second quartile status will consist of rankings between 84 and 88 minutes.

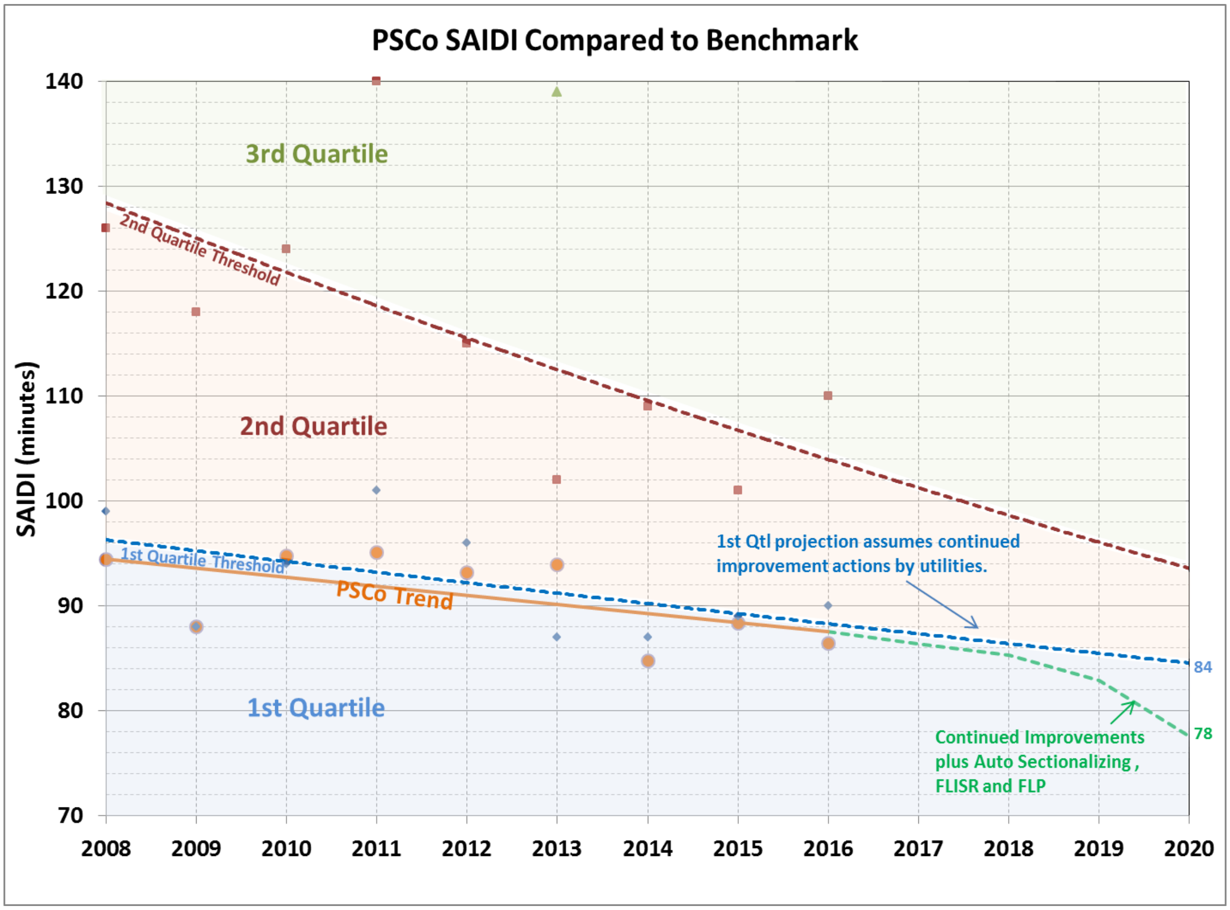
Q. WITH THE IMPLEMENTATION OF THE AGIS INITIATIVE, DOES THE COMPANY EXPECT TO MAINTAIN ITS FIRST QUARTILE SAIDI RANKINGS?

A. Yes. ADMS, AMI, FLISR and FLP all contribute to improving reliability on the distribution grid. The Company expects to see over 4.5 minutes of reduced

SAIDI minutes by 2020 through the initial implementation of the FLISR initiative and more than 1 minute through FLP. The Company will work to install these devices first in the locations of most benefit. We continue to strive for improvement through other areas also, including cable replacement, and overhead protection improvements.

The following graph shows projected reliability results for Public Service and the industry peer group through 2020. While the industry is expected to continue to improve, the Company expects to continue to be a leader in reliability performance through the capabilities of the AGIS programs. Even as early as 2020, when these programs are in the early stages of deployment, they begin having significant impacts on reliability.

1 **Figure JDL-D-5**



2 **Q. HOW DOES THIS RELIABILITY DISCUSSION RELATE TO THE COMPANY'S**
3 **OVERALL REQUEST FOR RECOVERY OF AGIS INVESTMENTS IN THIS**
4 **RATE CASE?**
5 A. While the Company has had strong reliability metrics for some time, the
6 investment in distribution grid advancement is expected to continue to support
7 and even improve the ability of Public Service to provide reliable electric service.

These outcomes underscore the value and importance of AGIS investments for the benefit of customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

John D. Lee

In 1979, I graduated from Kansas State University with a B.S. degree in Electrical Engineering. I began my employment with Public Service Company of Colorado in June 1979. I have held numerous positions both in the Distribution Engineering and Distribution Operations. Among these were Distribution Engineer, Standards Engineer, Senior Engineer, Manager Distribution Planning, Director Design and Layout, and various assignments as Director of Field Operations. I held the position of Director of Design, Construction and Maintenance for the Denver Metro East Region in Distribution Operations from 2004 until April 2015 where I was responsible for managing the design, construction and maintenance of gas and electric distribution systems in the Denver Metropolitan area including the cities of Denver, Aurora, Centennial, and Greenwood Village. Additionally, I managed the Contribution in Aide of Construction Extension Processing group led by Irma Nava, Manager Service Policy. In this role I directly managed the processing of construction payments, the award of Construction Allowance and the refund of construction payments associated with the administration of Company's Service Extension Policy. I am currently employed as Senior Director, Electric Distribution Engineering where my responsibilities are to direct the overall activities of Xcel Energy Electric Distribution Engineering, including strategic system planning, distribution area engineering, distribution standards, lifecycle planning & investment delivery. I am also responsible for the creation, management and forecasting of the electric distribution capital budgets across all Xcel Energy operating areas. I have been a Registered Professional Engineer in the State of Colorado since 1984.

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

* * * *

RE: IN THE MATTER OF ADVICE LETTER NO. 1748-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS PUC NO. 8-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**) PROCEEDING NO. 17AL-_______E**

AFFIDAVIT OF JOHN D. LEE
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, John D. Lee, 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 15 day of September, 2017.

John D. Lee
John D. Lee
Sr. Director, Electric Distribution Engineering

Subscribed and sworn to before me this 15th day of September, 2017.

Cindy L. Murphy
Notary Public

My Commission expires July 26, 2021

CINDY L MURPHY
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20094022652
MY COMMISSION EXPIRES JULY 26, 2021