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

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RE: IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR DISTRIBUTION GRID ENHANCEMENTS, INCLUDING ADVANCED METERING AND INTEGRATED VOLT-VAR OPTIMIZATION INFRASTRUCTURE	**))))))))))**	**PROCEEDING NO. 16A-____E**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF JOHN D. LEE</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

August 2, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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SUMMARY OF THE DIRECT TESTIMONY OF JOHN D. LEE

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 future of its electric distribution grid. He begins by describing the Company's current distribution system, which was designed for a one-way flow of information and power. The current system lacks real-time visibility into the condition of its distribution grid and the customer experience beyond the substation level. Therefore, if a customer is experiencing an outage the Company still relies primarily on the customer to report the outage. Additionally, the distribution system lacks automated controls that allow a utility to control equipment from a central location. The limitations of the current grid hamper the Company's ability to tailor voltage levels to system needs, provide customers with insight into their own energy usage, or support developing technologies such as distributed energy resources ("DER").

Further, Mr. Lee explains that the need to advance the electric distribution grid is driven by several key industry and customer changes, including: rapid technological advances in distribution management and voltage regulation/reduction; increasing customer needs and preferences for greater reliability and more insight into their energy usage; improving system average interruption duration index ("SAIDI") reliability standards, which necessitate advancing the distribution grid because Public Service has maximized the improvements it can make on the current system;[1] and the emergence of newer generation resources.

Mr. Lee then provides Public Service's technical strategy to meet these challenges through the Advanced Grid Intelligence and Security ("AGIS") initiative. He describes that Public Service's application for a Certificate of Public Convenience and Necessity ("CPCN") includes proposals to implement Advanced Metering Infrastructure ("AMI"); Integrated Volt-VAr Optimization ("IVVO"), which will enable voltage monitoring along the entire length of the feeder and selected end points (rather than only at the

[1] Due to increasing SAIDI requirements, with the current grid it is expected that Public Service's SAIDI ranking for reliability performance may no longer be amongst its peers by the year 2020. This likelihood contributes to the need for substantial system equipment and application upgrades.

substation) to allow the Company to utilize lower voltages across the entire feeder; and the components of the communications network known as the Field Area Network ("FAN") that are necessary to support AMI and IVVO. Mr. Lee introduces each of these components, as well as the Advanced Distribution Management System ("ADMS"), which is an integrated system of software and hardware that enables the use of AMI meter information with other intelligent field devices on the system; Fault Location Isolation and Service Restoration ("FLISR"), which significantly reduces the number of customers that suffer an outage for a prolonged period of time in the event of a fault; and Fault Location Prediction ("FLP"), which is a subset of FLISR that facilitates prediction of the location of a fault.

Mr. Lee explains that through the AGIS initiative, Public Service envisions moving from the predominantly one-way system that currently exists to an integrated system of centralized and decentralized energy resources that are connected and optimized through communications systems that share information from across the distribution grid. The advanced grid will leverage automation, real-time monitoring, and communication to locate and isolate disruptions in the system and improve safety, efficiency, and reliability of the system. AGIS will also enable greater customer choice by providing the infrastructure to allow the Company to offer new products, services, and technologies, including access to near real-time data regarding customer electric usage. The advanced grid will also include security protocols that will protect against, detect, and remedy cyber and physical threats. Additionally, the grid will provide timely and accurate information that will allow the Company to manage the increasing amount of DER entering our system.

Mr. Lee also outlines the overall implementation plan for the AGIS initiative, which can be summarized as follows:

Deployment Timeline

PROGRAM	DEPLOYMENT TIMELINE
ADMS	Planning: Ongoing Installation: Detailed design 2016-2017 System implementation 2017-2019
AMI	Planning: 2016-2017 Request for Proposal (“RFP”) issued July 2016 Vendor and contractor recommendation in November of 2016 Anticipated installation of first AMI meter in 2018 Install 95% of AMI meters by end of 2020.
FAN	Planning: Ongoing WiMAX and backhaul infrastructure 2016-2018 WiSUN (mesh network) implementation 2018- 2021
IVVO	Planning: 2016 Installation: Anticipated 2017-2022
FLISR	Planning: Ongoing Installation: 2016-2022

Mr. Lee also describes the overall anticipated costs of the CPCN Projects request, including how those costs are being developed and refined through Public Service internal experience, a Request for Information and Pricing (“RFx”) on major components, use of contingencies, and Request for Proposal (“RFP”). Mr. Lee summarizes the anticipated costs of the project as follows, and notes that Company witnesses Mr. Russell E. Borchardt, Mr. Chad S. Nickell, Mr. Wendall A. Reimer, and Mr. David C. Harkness describe the benefits and costs of the CPCN Projects in more detail:

CPCN Projects Capital Costs 2017-2021 ($M)

Capital ($Millions)	2016	2017	2018	2019	2020	2021	Total 2016-2021
AMI	0.5	3.5	31.7	117.0	68.6	16.8	238.1
IVVO	0.0	18.2	21.7	20.1	18.5	18.9	97.4
FAN	0.4	10.0	13.0	13.0	2.7	0.2	39.2
IT	3.3	56.9	50.4	4.6	5.6	2.7	123.4
Total	**4.1**	**88.6**	**116.8**	**154.6**	**95.3**	**38.6**	**498.1**

CPCN Projects O&M Costs 2017-2021 ($M)

O&M ($Millions)	2016	2017	2018	2019	2020	2021	Total 2016-2021
AMI	0.4	1.4	2.5	3.5	2.0	0.4	10.2
IVVO	0.0	1.0	1.3	1.7	2.2	2.7	8.9
FAN	0.2	0.6	2.0	3.6	4.7	5.0	16.0
IT	0.1	4.6	7.0	5.8	5.8	5.8	29.2
Total	**0.7**	**7.7**	**12.8**	**14.6**	**14.6**	**13.9**	**64.3**

Next, Mr. Lee provides a discussion of the program management and change management efforts necessary to affect the AGIS initiative and implement long-term, sustainable benefits. Finally, Mr. Lee discusses the alternatives to overall system advancement, including no change, implementation of a series of standalone upgrades, and implementation of only certain components of the AGIS initiative. Mr. Lee concludes that none of these options is superior to a system-wide advancement program that is integrated, intelligent, and designed to meet the needs of Public Service's customers and its overall distribution system.

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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
BPL	Broadband over Power Line
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
CBA	Cost-Benefit Analysis
CIS	Customer Information System
CMO	Customer Minutes Out
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
CRS	Customer Resource System
CSF	Cyber Security Framework
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DDOS	Distributed Denial of Service
DER	Distributed Energy Resources
DOS	Denial-of-service
DR	Demand Response
DSM	Demand Side Management
DVO	Distribution Voltage Optimization
EPRI	Electric Power Research Institute
ERT	Encoder Receiver Transmitter
ESB	Enterprise Service Bus
FAN	Field Area Network
FLISR	Fault Locate Isolation System Restoration

Acronym/Defined Term	Meaning
FLP	Fault Location Prediction
GFCI	Ground Fault Circuit Interrupter
GIS	Geospatial Information System
HAN	Home Area Networks
ICE	Interruption Cost Estimation
IDS	Intrusion Detection System
IEEE	Institute of Electrical and Electronics
IPS	Internet Provider Security
IT	Information technology
IVR	Interactive Voice Response
IVVO	Integrated Volt-VAr Optimization
kVAr	Kilovolt-amperes reactive
kVArh	Reactive power
kW	Kilowatt
kWh	Kilowatt hours
LTCs	Load Tap Changers
LTE	Long-Term Evolution
MDM	Meter Data Management
MitM	Man-in-the-Middle Attack
MPLS	Multiprotocol Label Switching
NCAR	National Center for Atmospheric Research
NOC	Network Operations Center
NPV	Net Present Value
O&M	Operations and Maintenance
OMS	Outage Management System
OT	Operational Technology
PTMP	Point-to-multipoint
Public Service	Public Service Company of Colorado
RF	Radio frequency
RFP	Request for Proposal
RFx	Request for Information and Pricing
RTU	Remote Terminal Units

Acronym/Defined Term	Meaning
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SGCC	Smart Grid Consumer Collaborative
SGIG	Smart grid investment grants
SIEM	Security Incident and Event Management
SVC	Secondary static VAr compensators
TOU	Time-of-use
USEIA	United States Energy Information Administration
WACC	Weighted Average Costs of Capital
WAN	Wide Area Network
WiMAX	Worldwide Interoperability for Microwave Access
WiSUN	802.15.4g Standard
Xcel Energy Inc.	Xcel Energy
XES	Xcel Energy Services Inc.

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DIRECT TESTIMONY AND ATTACHMENTS OF JOHN D. LEE

I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, RECOMMENDATIONS

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 provide an overview of Public Service's technical strategy to implement an advanced electric distribution grid in its service territory through the Company's Advanced Grid Intelligence and Security ("AGIS") initiative. I begin by describing the Company's current distribution system and the improvements the Company has made to the system over the years to improve our visibility and control into devices on our system. I explain why the Company's visibility and control of devices on the system is still limited despite those improvements.

Next, I address why this is the right time to implement AGIS and update our current system. I provide an overview of each of the foundational components of AGIS and how they interact to create an advanced grid that is integrated and will leverage automation, real-time monitoring, and communication to locate and isolate disruptions in the system and improve safety, efficiency, and reliability of the system. I describe how Public Service has maximized its ability to reduce its system average interruption duration index ("SAIDI") status through the limited advancements that have been made on the current system, and requires implementing AGIS technologies to maintain our SAIDI rankings amongst our peers by 2020. I explain why the components we selected for the AGIS initiative are the right components to implement an advanced grid.

I then describe how the Company will implement its AGIS initiative over the next five years, including an overview of the deployment timelines for each of the technical components. I provide an overview of overall costs, including contingencies for the components of the AGIS initiative, and I explain in detail the cost inputs for program and change management.

Finally, I discuss the system wide alternatives Public Service considered in lieu of implementing the AGIS initiative. I underscore that this is the right solution for us and our customers because the technologies and applications selected as components of the AGIS initiative work together to improve and convert our distribution system to an integrated grid consistent with current technology and system demands.

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

A. Yes, I am sponsoring the following:

- Attachment JDL-1: AGIS Initiative Deployment Maps
- Attachment JDL-2: Program and Change Management Costs

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR TESTIMONY?

A. I recommend that the Commission approve Public Service's request for a Certificate of Public Convenience and Necessity ("CPCN") for the implementation of the Advanced Metering Infrastructure ("AMI") and Integrated Volt-VAr Optimization ("IVVO") programs, as well as the components of the communications network (referred to as the Field Area Network or "FAN"), that are necessary to support AMI and IVVO (collectively, the "CPCN Projects"). As discussed by Company witness Ms. Alice K. Jackson, the Company is not requesting approval for the Advanced Distribution Management System ("ADMS"), Fault Location Isolation and Service Restoration ("FLISR"), or the FAN related to the FLISR implementation, given our view that these projects are in the ordinary course of business.

II. CURRENT PUBLIC SERVICE DISTRIBUTION SYSTEM

Q. PLEASE PROVIDE AN OVERVIEW OF PUBLIC SERVICE'S CURRENT DISTRIBUTION SYSTEM.

A. The Company's distribution system is a component of our electric system that allows the Company to deliver electricity from generation and transmission facilities to our customers. The distribution system is comprised of 150 distribution level substations that house transformers, and over 740 distribution feeder circuits, which consists of over 22,000 miles, that provide the path for delivering electricity from the distribution substation to the distribution customer transformer and then to customers.

Q. HOW WAS PUBLIC SERVICE'S DISTRIBUTION SYSTEM ORIGINALLY DESIGNED?

A. Like most utilities in North America, Public Service's distribution system was originally designed to accommodate only a one-way flow of electricity and information from the utility to the end use customer. This means that beyond the distribution substation, the Company has little insight into the workings of the distribution system or the customer experience. If you were to visualize this concept, imagine a map that was drafted to show information paths between the Company and its equipment. On that map everything after the substation - essentially the vast majority of the Company's distribution system - would be black because the current equipment on the system does not have the ability to communicate information past the substation level. Currently, to obtain information regarding the electric grid's status such as meter readings, storm-damaged equipment and facilities, or voltage levels, the Company has to send workers out into the field to gather this information. In addition, the current system relies on mostly manual and local control schemes to operate the distribution system.

Q. HOW DOES THE LIMITED AMOUNT OF INSIGHT INTO THE DISTRIBUTION SYSTEM IMPACT OPERATIONS?

A. The limited visibility and control of devices on the system translates to a lack of ability to efficiently manage the voltage level on the system. Our tariffs require us to keep voltage within a specific range. The current system design does not inform the Company if the end use customer is outside of the allowable voltage range; therefore, the Company can only obtain this information if the customer calls to complain about conditions that indicate their voltage is outside of the range. For example, if customers have high voltage they may complain that their incandescent lights are burning out quickly, or if customers have low voltage they may complain that the motor in their refrigerator burned out or other appliances are not operating efficiently. The best way for the Company to stay within the tariffed voltage range is to maintain a voltage level at the substation that is near the high level of the range at all times. This ensures that under any condition the last customer on the system will not have voltage that drops below the acceptable range. However, operating the system at higher voltage levels costs customers more money because system devices do not operate efficiently and use more energy.

Q. DOES THE CURRENT SYSTEM ALSO LIMIT THE COMPANY'S ABILITY TO IDENTIFY OUTAGES?

A. Yes. As I have described above, the Company does not have visibility into the system beyond the substation level. As a result of the limited communication capabilities, the Company primarily gains outage information through customer power loss calls. The Company then analyzes the locations of the outage calls to determine what aspect of the distribution system lost power. Ultimately, to obtain information regarding current meter readings, outages, storm-damaged equipment and facilities, or to measure voltage, the Company has to send workers into the field to gather this information manually.

Q. HOW DOES THE CURRENT SYSTEM LIMIT THE TRANSFER OF INFORMATION BETWEEN THE COMPANY AND THE CUSTOMER?

A. Without information beyond the substation level, we cannot provide customers with near real-time power information to assist them in managing their electric usage efficiently. The current distribution system can only provide customers with usage information on a monthly basis through the Company's billing system. As described in more detail in the Direct Testimony of Company witness Mr. Russell E. Borchardt, the advanced grid technology available today can provide customers with near real-time information upon request, meaning customers will have access to usage information that is only a few minutes old.

Q. CAN YOU PROVIDE MORE DETAIL EXPLAINING HOW THE CURRENT DISTRIBUTION SYSTEM IS OPERATED?

A. Yes. The current system is primarily operated through manual and local control schemes that require human labor to complete an operation. For example, all the disconnecting switches are manually operated switches for non-automated feeders. If there is a fault on any feeder segment, the circuit breaker will trip at the substation. When this occurs, a field crew has to travel along the feeder lines to find the location of the fault. The practice of sending workers into the field is known as a "truckroll". After the crew locates the location of the fault, they manually open immediate upstream and downstream disconnecting switches to isolate the faulty feeder section. After the fault section of the feeder is repaired, the switches are manually closed to restore service to the feeder. Automating this process would reduce crew field time and enable earlier responses to faults.

Q. HAS THE COMPANY UPDATED THE ORIGINAL DESIGN OF THE DISTRIBUTION SYSTEM WITH AUTOMATION OVER THE YEARS?

A. Yes. The Company has completed three projects in prescribed areas that have enabled automation with a limited amount of remote monitoring and control. One project is the IntelliTeam® capable devices that were installed along the two feeders that provide electricity to the municipalities of Blackhawk and Central City from the Idaho Springs substation. If an outage occurs on one feeder, these devices are able to switch the load to the other feeder without manual intervention. Through this automation, the system can reconfigure itself within seconds to isolate the outage area and restore power to the remaining customers served by the feeder that endured an outage.

Additionally, the IntelliTeam® devices will inform the Company in near real-time the specific devices that the outage occurred between. This assists the Company in streamlining its response to repair a failure. This is important for the customers in Blackhawk and Central City because without these devices, crews would be required to investigate over approximately 32 miles of distribution line located in rough terrain that includes significant elevation changes to locate the outage, and that can delay restoration efforts to affected customers.

While IntelliTeam® devices provide these important benefits, they are not as flexible as fault location devices that are now available and which can function within a broader strategy for advancing the distribution grid. Therefore, while Public Service finds the IntelliTeam® devices useful, we propose to implement different technologies going forward, as discussed later in my Direct Testimony. The IntelliTeam® devices will eventually be replaced with the new technologies.

Q. WHAT ARE THE OTHER TWO AUTOMATION PROJECTS THE COMPANY HAS IMPLEMENTED?

A. The other two projects are the IntelliTeam® capable devices installed in Breckenridge and the SmartGridCity Project that installed AMI meters in Boulder as part of a pilot in 2008. The Breckinridge IntelliTeam® project was much like the Blackhawk and Central City project described above. The SmartGridCity pilot project involved implementing AMI and smart meters at a time when the technology was new and, unlike the technology utilized in today's advanced grids, had not become an industry standard. After installation, the system worked well through the initial years, providing the Company with outage information, near real-time data that customers could access through the Internet, and increased visibility into the grid.

However, as I describe later in my testimony, the technologies that were used in SmartGridCity's pilot communication network did not continue to be developed by the industry and vendors ceased supporting those technologies. As a result, the Company lost much of the visibility into the system it had gained through the project, and as equipment fails we continue to lose more visibility. As I discuss in the next section of my testimony, technologies available today to operate electric grids have significantly advanced.

Q. ARE THERE OTHER WAYS IN WHICH PUBLIC SERVICE HAS UPGRADED THE DISTRIBUTION SYSTEM?

A. Yes. Throughout the years, as distribution equipment replacements are needed, the Company replaces that equipment with updated technology that becomes available and is compatible with the current limited distribution system. For example, the functional capabilities of reclosers have evolved over the years. A recloser is a circuit breaker equipped with a mechanism that can automatically close the breaker after it has been opened due to a fault. When I started with the Company, over 35 years ago, hydraulic reclosers were primarily used. Those reclosers operated as intended, but their capabilities were limited in their ability to sense faults and to coordinate with other devices.

Today, new reclosers are equipped with vacuum interrupting technology and digital electronic controls. These reclosers require less maintenance, provide enhanced operator safety, and add application flexibility that allows them to be used in numerous ways. The programmable electronic controls allow close coordination with other devices and the enhanced sensing capabilities ensure more accurate operation and provide information that helps evaluate system performance. When connected with a communication network, the recloser can communicate the operating information and a field crew can be dispatched to fix a fault when the reclosing operation doesn't eliminate the problem.

Q. HAS THE COMPANY UPGRADED CUSTOMER METERS OVER THE YEARS?

A. Yes. In the mid-1990s, the Company upgraded from meters that required manual readings to Automatic Meter Reading ("AMR") meters. Each AMR meter is equipped with a one-way radio frequency communication module that collects and transmits meter reading data from the meter to a receiver mounted in trucks. As a result, the Company's communication with AMR meters is limited to the monthly truck roll. AMR meters are discussed in more detail in the Direct Testimony of Company witness Mr. Borchardt.

Q. WHAT TYPE OF INFORMATION DO THE AMR METERS PROVIDE?

A. While the AMR technology enables regular meter reads for meters that are not easily accessible, the information transmitted via the radio signal is limited to billing information and this information is only transferred when a meter reading truck drives by the location and pings the meter for the billing information. As I describe in more detail later in my Direct Testimony and as described in the

Direct Testimony of Company witness Mr. Borchardt, the capabilities of advanced meters far surpass this technology.

Q. WHAT IS THE IMPACT OF THESE UPDATES ON THE CURRENT DISTRIBUTION SYSTEM?

A. Even with the Company's continued investments over the years that upgrade the grid from its original configuration, the impact is not sufficient to change the visibility into the one-way information and power flow of the existing distribution system. Public Service still lacks real-time visibility into the condition of its entire distribution grid and the customer experience beyond the substation level. Therefore, as I describe earlier in this section of my testimony, if a customer is experiencing an outage the Company still primarily relies on the customer to report the outage in order to know an outage occurred. Additionally, as described above, the distribution system continues to lack automated controls that allow a utility to adjust and control individual pieces of equipment or groups of equipment from a central location.

Q. HOW DOES THE LACK OF VISIBILITY INTO THE DISTRIBUTION SYSTEM IMPACT THE AMOUNT OF DISTRIBUTED ENERGY RESOURCES ("DER") THAT IS ABLE TO ENTER THE ELECTRIC GRID?

A. The current distribution system does not allow the Company to accurately measure the amount of Distributed Energy Resources ("DER") flowing to and from the grid. Instead, the Company has to rely on conservative estimates to estimate the amount of DER that is entering and leaving the electric grid. These highly variable generation sources can create operational complexities, such as protection or voltage regulation concerns.

For example, as energy from highly variable DER enters and leaves the grid, customers may experience increased levels of voltage flicker. When there are high levels of DER on a feeder, protective equipment such as reclosers or substation breakers may not operate as intended because of the inability to differentiate between loads, DER generated power and system faults. The lack of visibility to the direction and magnitude of power flow may limit the Company's ability to identify and take actions to address potential problems. This is a concern given that the demand for DER has risen in recent years and is expected to continue to rise rapidly.

Q. WHAT DO YOU CONCLUDE WITH RESPECT TO THE CURRENT STATE OF THE PUBLIC SERVICE DISTRIBUTION GRID?

A. Overall, Public Service has made improvements to the electric grid and necessary investments to ensure our system is functioning properly. With that said, the technology available to operate electric grids has significantly advanced. It is now possible to implement equipment and systems that will provide the Company with real-time visibility into the grid that we currently lack. While the Company has implemented some of these technologies in a few areas, it is time to expand the advancing technology to our entire electric grid. As I discuss in the next section of my testimony, the Company's AGIS initiative comprises the Company's technical strategy for meeting these needs in the years ahead.

III. TECHNICAL STRATEGY FOR THE DISTRIBUTION GRID

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

A. Public Service envisions moving from the predominatly one-way system that currently exists to an integrated system of centralized and decentralized energy resources that are connected and optimized through communications systems that share information from across the distribution grid. The advanced grid will leverage automation, real-time monitoring, and communication to locate and isolate disruptions in the system and improve safety, efficiency, and reliability of the system. The advanced grid will enable greater customer choice by allowing customers to adopt new products, services, and technologies, including access to near real-time data regarding their electric usage. The advanced grid will also include security protocols that will protect against, detect, and remedy cyber and physical threats. Additionally, the advanced grid will provide timely and accurate information that will allow the Company to manage the increasing amount of DER entering our system. This will be accomplished through the Company's AGIS , which consists of multiple programs that work together to improve and update our distribution system.

Q. WHY IS IT IMPORTANT TO IMPLEMENT AGIS AND UPDATE THE CURRENT ELECTRIC DISTRIBUTION GRID AT THIS TIME?

A. The need to complete the AGIS initiative to update the grid is driven by a confluence of factors including rapid technological advances, changing customer needs and preferences, increasing industry reliability standards, and emerging generation resources and public policy.

- **Rapid Technological Advances:** Recently, computer-based remote control, automation, and two-way communication technology, which have been used for decades in other industries, are rapidly being deployed on the electrical grid. As a result of these technological advances, older equipment that does not enable these new technologies is being phased out. For instance, one-way AMR meters are slowly being discontinued by manufacturers as they are replaced with two-way AMI meters. To ensure that we have replacement parts for key elements of our system, we need to upgrade to keep pace with these advancements.
- **Changing Customer Needs and Preferences:** The needs and expectations of the Company's customers and stakeholders have evolved and continue to evolve while the design of the infrastructure has remained mostly unchanged. Today's utility customers expect a more robust, reliable, and resilient system, which is fueled by the increasing dependency on the connectivity of digital devices. Thus, electric service interruptions lead to greater dissatisfaction and negative economic impact than they did decades ago.

  Additionally, customers desire more insight and visibility into the energy choices that they are making. Implementing the AGIS initiative assists in that effort by giving customers access to near real-time energy usage information that will assist them in making energy usage decisions.

This is discussed more thoroughly in the Direct Testimony of Company witness Mr. Borchardt.

- **<u>Increasing Industry Reliability Standards:</u>** The reliability indicator for the utility industry is SAIDI, which is the average duration of interruptions customers experience during a year quantified in minutes. A utility's SAIDI is used to rank its reliability performance against its peers. Currently, Public Service ranks in the first quartile for 2014 with a SAIDI value of 88 minutes. The 2015 SAIDI rankings will be available in August of 2016, but the Company expects to continue to be in the first quartile with a SAIDI value of 89 minutes. However, the industry expectations are becoming more stringent as technology for advanced grids develops. It is expected that by 2020, to achieve first quartile SAIDI status utilities will need a SAIDI of 82 minutes, and the second quartile will consist of ranking between 83 and 90 minutes. Without implementing the advanced technologies through the AGIS initiative, the Company will not maintain our position amongst our peers in SAIDI by 2020.
- **<u>Emerging Generation Resources and Public Policy:</u>** In addition to the SAIDI issues noted above, it is expected that the amount of integration of DER into the distribution system will rapidly rise in coming years. As a result, the Company needs to have the visibility and control over the distribution system in order to enable integrating voltage with these highly variable generation resources.

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, and Geospatial Information System ("GIS"). Some of these components, such as ADMS, GIS and some of the Intelligent Field Devices, are already being implemented by the Company through the ordinary course of business.[2]

Q. WOULD YOU PLEASE BRIEFLY DESCRIBE EACH OF THE FOUNDATIONAL COMPONENTS?

A. Yes.

- **<u>Advanced Distribution Management System ("ADMS"):</u>** ADMS, which is being implemented in the ordinary course of business, 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 DER, outage events, feeder switching operations and advanced applications such as FLISR and IVVO, which I

[2] In addition to the foundational programs, two recently approved Innovative Clean Technology 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. In Proceeding No. 15A-0847E, the Commission authorized the Panasonic project, a utility–scale battery and rooftop solar array designed to function both on the regional grid and also as an independent microgrid. The Commission also authorized the Stapleton project, which will consist of six customer-sided and six utility–sided batteries to test solar energy storage and on-peak discharge. The details of these projects are addressed in the separate proceeding in which they were authorized by the Commission (Proceeding No. 15A-0847E).

described below in my discussion of advanced applications for intelligent field devices. ADMS gives access to real-time and near real-time data to provide all information on an 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 manages each of the other AGIS components described below. ADMS is discussed in more detail in the Direct Testimony of Company witness Mr. Nickell.

- **Advanced Meter Infrastructure ("AMI"):** AMI meters, which are being requested as part of the CPCN in this proceeding, are able to measure and transmit voltage, current, and power quality data and can act as a "meter as a sensor," providing 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, identify outages without customer reporting, respond efficiently to metering and usage issues, and allow remote service disconnects and reconnects. AMI is discussed in more detail in the Direct Testimony of Company witness Mr. Borchardt.
- **Field Area Network ("FAN"):** 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. The components of the FAN that support AMI and Integrated Volt-VAr Optimization, discussed immediately below, are being requested as part of the CPCN in this proceeding. The FAN that is implemented separate from those two AGIS components will be done in the ordinary course of business. The FAN is discussed in more detail in the Direct Testimony of Company witness Mr. Wendall A. Reimer.

- **Advanced Applications for Intelligent Field Devices** include the following advanced applications and associated field devices that 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 capacity to host DERs. IVVO is included in this CPCN request.
  - Fault Location Isolation and Service Restoration ("FLISR") is an application that involves 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. FLISR will be implemented in the ordinary course of business.

- Fault Location Prediction ("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. FLP will be implemented in the ordinary course of business.

IVVO, FLISR, FLP, and the associated intelligent field devices are discussed in more detail in the Direct Testimony of Company witness Mr. Nickell.

- **Geospatial Information System ("GIS"):** GIS provides location information about all physical assets that make up the distribution system. The records also include specification information of 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. While GIS is an existing system, the Company needs to engage in a data gathering effort to validate and update the information in GIS because the ADMS model needs accurate information to operate effectively. This work will be done in the ordinary course of business.

Underlying all of these programs are the information technology ("IT") support and cyber security protections necessary to operate a secure, technologically-advanced grid in today's world, as discussed by Company witness Mr. Harkness.

Q. WHY IS THE AGIS INITIATIVE MADE UP OF THESE COMPONENTS?

A. Overall, Public Service developed the components of the AGIS initiative to create an advanced grid that is more reliable and efficient, that benefits the environment and reduces costs by lowering unnecessary power production, that provides customers with greater visibility into their energy usage to enable energy choices that reduce usage, that will allow the ability to measure and accommodate the increased integration of DER, and that is secure because it will rely on Company owned communications networks rather than third-party networks. Later in my testimony, I discuss the alternatives Public Service considered to achieve these benefits on a system-wide basis, and note that the technical witnesses address individual technology alternatives the Company also considered.

Q. WHAT COMPONENTS OF AGIS ARE DESCRIBED IN THIS APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY ("CPCN PROJECTS")?

A. As described in the Direct Testimony of Company witness Ms. Jackson and above in my Direct Testimony, this CPCN Projects Application seeks approval to implement AMI meters, IVVO, and the associated components of the FAN. The Company is not requesting approval of ADMS, FLISR, FLP, GIS, or the FAN as it relates to the FLISR implementation.

Q. WHY IS THE COMPANY DISCUSSING THE AGIS COMPONENTS OF ADMS, FLISR, FLP, GIS, AND THE PORTION OF FAN RELATED TO FLISR IN THIS FILING IF THEY ARE NOT PART OF THE CPCN APPLICATION?

A. The components discussed in this filing are all aspects of what is envisioned by an advanced integrated grid through the AGIS initiative. Components such as ADMS and the FAN associated with FLISR are foundational to operating the distribution grid, and are therefore necessary in the ordinary course of maintaining and operating the distribution grid. But since they are also foundational to less ordinary components of the AGIS initiative addressed in this CPCN, it is necessary to describe both these foundational aspects as well as those specific components being requested in this CPCN filing to provide a complete picture of the Company's envisioned grid.

A. <u>AMI Strategy</u>

Q. WHY IS PUBLIC SERVICE PROPOSING TO TRANSITION FROM AMR TO AMI TECHNOLGY?

A. First, as I mention above, the Company's current AMR meters were installed in the mid-1990's and their technology is limited to monthly drive-by meter reads to collect billing data. The AMR meters do not provide the numerous additional operational, customer and financial benefits that are supported by advanced meters available in today's market. Advanced meters are considered the "next generation" of meter technology because their operational abilities extend far beyond AMR meters.

Operationally, 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 or eliminate 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. As discussed in the Direct Testimony of Company witness Ms. Jackson, advanced meters will also be able to support new rate designs that cannot be supported by the Company's current AMR meters. The benefits of AMI meters are discussed in more detail in the Direct Testimony of Company witness Mr. Borchardt.

Q. DID PUBLIC SERVICE CONSIDER IMPLEMENTING ADVANCED METERS INSTEAD OF AMR IN THE 1990s?

A. Yes. In 1994, when the Company opted to install AMR meters, advanced meter technology was available and Public Service engaged in a thorough assessment of that technology at the time. At the time, two-way meter technology was still in its infancy and was not ready for large-scale deployment. As a result, the Company decided to stay with AMR technology until the two-way AMI and advanced meter technology was further developed.

As Company witnesses Ms. Jackson and Mr. Borchardt discuss in their Direct Testimony, AMI technology is now sufficiently advanced and deployed to warrant adoption by Public Service on a broad basis.

Q. IS THE AMI PROGRAM PROPOSED IN THIS APPLICATION LIKE THE SMARTGRIDCITY INITIATIVE IN BOULDER THAT YOU MENTIONED EARLIER IN YOUR TESTIMONY?

A. There are significant differences between the AMI used in SmartGridCity and the AMI that is being proposed in this proceeding as part of the AGIS initiative. The primary difference is that the Boulder SmartGridCity metering is informational and not interactive like the AGIS initiative. The SmartGridCity pilot provided a sufficient amount of information to advise the Company on the aspects of the system that needed repair. The AGIS initiative, including AMI, is an interactive system where the proposed technologies and systems have the ability to automatically update each other creating the ability for the distribution system to essentially repair itself, or as stated within the industry, the ability to self-heal.

The other significant difference is the communication network that is being proposed. As part of the AGIS initiative the Company is proposing to implement the FAN, which is a robust secure communications network that provides multiple paths for the Company and infrastructure to communicate necessary information such as meter data or system voltage information. With the Boulder SmartGridCity pilot, a variety of communications technologies, including Broadband over Power Line (“BPL”), fiber optic cable, 3G Cellular and microwave, were utilized to build the current communications infrastructure network, along with the installation of an older AMI meter technology.

When the communication network in Boulder was initially installed in 2008, it worked well for several years and provided us with increased visibility into the grid, outage information and provided customers with usage information via the Company's website. While BPL was a promising innovative technology when implemented, it did not evolve in the market place and, in fact, is no longer supported. When the company that supported our BPL went out of business in 2013, Public Service lost the visibility into the system that it gained through the SmartGridCity pilot. The technology, equipment and software that are proposed as part of the AGIS initiative constitute a more advanced and robust platform that has become available and widely adopted since the SmartGridCity pilot.

Q. WHY DIDN'T THE COMPANY IMPLEMENT AMI TECHNOLOGY THROUGHOUT ITS ENTIRE DISTRIBUTION SYSTEM IN THE INITIAL YEARS OF SMARTGRIDCITY WHEN IT WAS OPERATING SUCCESSFULLY?

A. At that time, the Company did not recommend implementing AMI beyond the SmartGridCity pilot project. The Company determined that while SmartGridCity was successful, the AMI technology of the time was not required to realize significant customer value because AMR meters with similar capabilities had already been deployed in Public Service's territory.[3]

[3] *See* Commission Proceeding No. 10A-124E, Direct Testimony of Mr. Michael G. Lamb.

Q. WHY IS IT CURRENTLY APPROPRIATE TO IMPLEMENT AMI TECHNOLOGY THROUGHOUT THE COMPANY'S SERVICE TERRITORY?

A. AMI technology has advanced and been developed to the point where many additional benefits are available and the technology is well-known. At the time Public Service advised against broader deployment of AMI, it was true that the Company did not need to implement AMI technology system-wide in order to obtain customer benefits. In fact, it is still true today that some customer benefits can be obtained through the use of an advanced grid without AMI meters. For example, sensors can be installed to lower voltage system wide or standalone automation, like the proposed IVVO technology, and IntelliTeam® or FLISR, respectively.

With that said, the current capabilities of AMI meters and the communication system used by advanced grids have developed to the point where it is now the Company's conclusion that deployment of AMI meters throughout the Company's service territory is the best option. AMI meters today are not standalone meters like the AMI meters of SmartGridCity. Today's AMI meters are capable of operating as a voltage sensor, and they are a critical component of the mesh communication network described later in my testimony. These advancements allow one device, the AMI meter, to perform functions that historically required multiple standalone technologies and systems.

Q. IS THE COMPANY EVALUATING WHETHER AMI METERS SHOULD BE DEPLOYED IN THE COMPANY'S NATURAL GAS SERVICE TERRITORY?

A. Yes. At this time the Company is evaluating the relative costs and benefits of providing AMI meters to natural gas customers. Company witness Ms. Jackson discusses this matter further in her Direct Testimony.

B. <u>IVVO Strategy</u>

Q. WHY IS PUBLIC SERVICE PROPOSING TO IMPLEMENT 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. PLEASE EXPLAIN HOW IVVO IS DIFFERENT THAN THE DISTRIBUTION VOLTAGE OPTIMIZATION THAT THE COMPANY PROPOSED IN PROCEEDING 13A-0686EG.

A. Distribution Voltage Optimization ("DVO") was originally proposed as a standalone program that would not communicate with other programs. In comparison, IVVO is based on the ADMS implementation and operates in a manner that is more integrated with our entire distribution grid. IVVO provides a higher degree of control.

More specifically, implementing DVO entailed the purchase and integration of a specific software platform that would be isolated from the Company's other systems. In contrast, IVVO will run on the Company's integrated ADMS system and will operate with other distribution grid software applications. DVO required the build-out of an isolated communications network, whereas IVVO will use the proposed FAN communication network that will be integrated with AMI meters and other advanced applications for intelligent field devices. Additionally, DVO required the installation of at least nine voltage sensors per feeder (there are over 740 feeders) in order to monitor system voltage, while IVVO will use the AMI meters' ability to operate as a voltage sensor.

Overall, unlike IVVO, DVO is not a dynamic system and when the Company implements changes to other platforms DVO would require a manual update. IVVO will be configured in a manner so that IVVO will adapt without manual updates when there are changes to other platforms within the system. Additionally, it was anticipated that DVO would result in a 2% overall system voltage reduction, but it cannot expand beyond a 2% reduction. The implementation of IVVO is expected to initially produce a 2% overall system voltage reduction, but, in the future IVVO may be able to expand that reduction to 3%-5% on certain system feeders through secondary static VAr compensators ("SVC"). The capabilities and function of IVVO and SVCs are described more thoroughly in the Direct Testimony of Company witness Mr. Nickell.

C. FAN Strategy

Q. WHY IS PUBLIC SERVICE PROPOSING FAN TECHNOLOGY?

A. As described in more detail in the Direct Testimony of Company witness Mr. Reimer, 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. HOW DOES THE FAN WORK?

A. There are two distinct technologies that comprise the FAN. First is the Worldwide Interoperability for Microwave Access ("WiMAX"), which is a point-to-point communication system that transfers information from the substation to a communication point on the distribution system. Second is the Wireless Smart Utility Network ("WiSUN"), which transfers information between meters through a mesh network. The mesh network allows multiple devices to connect with each other, which provides multiple potential communication routes ensuring a robust communications network.

Q. HOW DOES THE FAN INTEGRATE 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. AMI and advanced meters are discussed in more detail in the Direct Testimony of Company witness Mr. Borchardt. IVVO is discussed in more thoroughly in the Direct Testimony of Company witness Mr. Nickell. The FAN is discussed in more detail in the Direct Testimony of Company witness Mr. Reimer.

D. ADMS Strategy

Q. WHY IS THE COMPANY IMPLEMENTING THE ADMS TECHNOLOGY?

A. ADMS is considered a foundational element of the AGIS initiative because it is necessary to implement in order to build a system that leverages the technologies that are needed for the advanced grid of the future. ADMS is an integrated system of software and hardware that operators will use to obtain information of events on the electric grid and respond to those events through corrective actions through ADMS. The information ADMS has is received through AMI meters and other intelligent field devices on the system to bring that information into the program and accurately model the system as it currently is. ADMS is discussed more thoroughly in the Direct Testimony of Company witness Mr. Nickell.

Q. WOULD YOU IMPLEMENT THE ADMS EVEN WITHOUT THE PROPOSED COMPONENTS INCLUDED IN THIS CPCN APPLICATION?

A. Yes. ADMS is a component of the AGIS initiative that is being implemented through the ordinary course of business. ADMS is a network model that can perform similar functions to the Company's current Dynamic Energy Management System ("DEMS"), and it also has the capability to integrate all of the technologies and systems that are part of the Company's AGIS initiative. Energy Management Systems ("EMS") are the network model and associated hardware and software that utilities have traditionally used to monitor and control generation, transmission and substation assets. Historically, EMS provides limited visibility and control of distribution assets and does not have a network model like ADMS. As I have previously described and as discussed in more detail in the Direct Testimony of Company witness Mr. Nickell, there are substantial benefits to building the network model of the distribution system in ADMS and moving the monitoring and control functions for the distribution system from DEMS. The increasing demands being placed on our distribution system has necessitated the need for the enhanced functionality that ADMS can provide rather than adding to DEMS. This upgrade is considered a normal evolution of the Company's business function and therefore is being completed in the ordinary course of business.

E. <u>FLISR and FLP Strategy</u>

Q. WHY IS PUBLIC SERVICE IMPLEMENTING FLISR?

A. As described in more detail in the Direct Testimony of Company witness Mr. Nickell, 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 application reduces the number of customers that suffer an outage for a prolonged period of time in the event of a fault.

Q. WHY IS PUBLIC SERVICE IMPLEMENTING FLP?

A. FLP is a subset of the FLISR application. It 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. This is described more thoroughly in the Direct Testimony of Company witness Mr. Nickell. Together, FLISR and FLP can help the Company respond to major events on the system.

Q. WHAT IS A "MAJOR EVENT"?

A. Major events are situations where the volume of events that are impacting the system overwhelms the Company's ability to respond. As a result, the Company is forced to prioritize its corrective activities based on which corrective actions will restore power to the majority of the customers that are currently experiencing an outage. During major events, the Company almost always prioritizes switching loads to restore customers as quickly as possible.

Q. WHAT IS THE IMPACT OF IMPLEMENTING FLISR AND FLP ON MAJOR EVENTS?

A. Currently, switching loads in the case of a major event requires a significant amount of time because manual analysis and customer calls are used to asses which feeders need to be switched. FLISR and FLP will automate this analysis and the Company will have the ability to switch feeders within minutes, or even less, without having to deploy employees or engage in customer calls to gather data. Additionally, FLISR and FLP will provide the Company with more visibility and detail regarding why the event occurred.

For example, a customer has a downed lined in their back yard, but they are also served off of a feeder where multiple customers are experiencing an outage because a recloser is out. Currently, the Company will fix the recloser and be unaware that the customer with the downed power line was still without power unless that customer calls the Company and conveys that information. FLISR and FLP will provide the Company with the insight to the additional corrective activity needed for the downed power line without customer reporting. Overall, implementing FLISR and FLP allows the Company to efficiently restore power with the use of fewer resources.

F. <u>GIS</u>

Q. WHY IS GIS CONSIDERED A FOUNDATIONAL COMPONENT OF THE AGIS INITIATIVE?

A. As I describe earlier in my testimony, GIS provides 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. If it is determined that additional specification information is needed to supplement current records the Company intends to engage contractors to obtain that information from field inspections. The Company has not selected a vendor for this work yet because we are still in the planning and design phase of this effort.

G. <u>Summary of Overall AGIS Strategy</u>

Q. CAN YOU SUMMARIZE THE COMPANY'S OVERALL STRATEGY FOR IMPLEMENTATION OF THE AGIS COMPONENTS?

A. Yes. The Company has identified this package of interrelated grid advancement components as the appropriate manner in which to move Public Service's distribution grid into the future by addressing customer needs, voltage and fault issues, two-way communication needs, and the overall reliability and stability of the distribution grid.

Q. HOW DID THE COMPANY IDENTIFY THAT THESE COMPONENTS WERE THE CORRECT COMPONENTS FOR THE AGIS INITIATIVE?

A. In order to address the changes necessary to move Public Service's distribution grid into future, the Company determined that an integrated ADMS system was the best approach as opposed to stand-alone systems to address each need individually. As I describe above, ADMS provides the platform for that integrated system. It allows the Company's operators to manage the grid through one system by providing a network model that communicates with all of the proposed AGIS technologies, and incorporates the ability for control devices on the system to automatically update the network model. Therefore, the components of AGIS are intended to work together efficiently and as an integrated system.

For example, if FLISR reconfigures the power flow on the system by switching load on distribution feeders, the voltage level of the affected feeders changes and the AMI meters communicate that voltage information over the FAN and it is ultimately reflected in ADMS. The IVVO software application in ADMS will register the voltage change and automatically adjust the voltage levels on the system to the optimum range. As the example illustrates, each component of AGIS was selected based on its ability to integrate and automatically operate with the other AGIS components. Later in my testimony, I discuss the various system-wide alternatives Public Service considered.

IV. <u>AGIS IMPLEMENTATION</u>

A. <u>Timing of implementation</u>

Q. HOW IS THE COMPANY PLANNING TO IMPLEMENT ITS AGIS INITIATIVE?

A. Due to the integrated nature of the various components of the AGIS initiative, certain components must be placed in-service first, as they provide the necessary foundational elements for later components. Thus, Public Service's AGIS initiative will not be completed in a single project effort or within a single year; rather, the necessary facilities will be constructed and placed in-service over time, and the system will grow and layer additional capabilities and functionality that will deliver value to our customers.

Q. CAN YOU PROVIDE AN OVERVIEW OF THE DEPLOYMENT TIMELINE FOR THE AGIS INITIATIVE?

A. Yes. The table below provides an overview of the deployment timeline for the various programs that comprise the AGIS initiative. The detailed timelines for each of these programs are further discussed by the individual technical witnesses.

TABLE JDL-1-DEPLOYMENT TIMELINE

PROGRAM	DEPLOYMENT TIMELINE
ADMS	Planning: Ongoing Installation: Detailed design 2016-2017 System implementation 2017-2019
AMI	Planning: 2016-2017 Request for Proposal ("RFP") issued July 2016 Vendor and contractor recommendation in November of 2016 Anticipated installation of first AMI meter in 2018 Install 95% of AMI meters by end of 2020.
FAN	Planning: Ongoing WiMAX and backhaul infrastructure 2016-2018 WiSUN (mesh network) implementation 2018- 2021
IVVO	Planning: 2016 Installation: Anticipated 2017-2022
FLISR	Planning: Ongoing Installation: 2016-2022

Q. WHAT WILL BE THE FIRST COMPONENT OF THE AGIS INITIATIVE TO BE PLACED IN-SERVICE?

A. Public Service's current plan is to install and deploy FAN-specific components (such as the WiMAX and WiSUN network devices) and complete the installation approximately six months in advance of the deployment of AMI meters and IVVO devices. The FAN communication network is necessary for the other technology components to operate. As an example, if a set of meters in a particular area is replaced with AMI meters, but the FAN has not been deployed and is not operating, those meters will not be able to be read automatically. However, if the FAN is deployed prior to AMI meters being installed, the meters would be able to immediately communicate with the network, and as they are installed the Company can verify communications.

Q. ARE THERE OTHER INTERDEPENDENT PROGRAMS WITHIN AGIS THAT NECESSITATE A PARTICULAR DEPLOYMENT STRATEGY?

A. Yes. FLISR is dependent on implementation of both FAN and ADMS to enable full functionality. As the foundational software system of the AGIS initiative, ADMS contains the network model and associated information that FLISR requires to work. FLISR runs on the ADMS platform and model. The FAN communication system is necessary to enable the software application component located centrally in the Company's control center to talk to, monitor, and operate the various field devices located throughout the distribution system. With that said, there will be instances where FLISR devices are installed on the system prior to ADMS being fully operational. In those instances, the Company will wait to connect the FLISR devices to ADMS until it is in service.

IVVO is also dependent on the implementation of both FAN and ADMS because IVVO needs the communication network of the FAN in order to process the voltage information, and ADMS is the software module that IVVO uses to model the entire system.

Finally, AMI and advanced meters are dependent on the FAN to communicate the data it collects back to the ADMS system and the head-end meter software that inputs the meter data into the billing system.

Q. ARE THERE OTHER PROGRAMS THAT LAY THE FOUNDATION FOR LATER INSTALLATIONS?

A. The GIS data is foundational because it is necessary to import accurate system knowledge into ADMS. For example, ADMS needs the information related to the physical attributes of the system, such as pole line configurations and the size of feeder lines. This is discussed in the Direct Testimony of Company witness Mr. Nickell.

Q. HAS THE COMPANY DEVELOPED A SCHEDULE FOR WHEN EACH COMPONENT OF THE AGIS INITIATIVE WILL BE DEPLOYED IN SPECIFIED AREAS OF THE COMPANY'S SERVICE TERRITORY?

A. Yes. Please see Attachment JDL-1 to my Direct Testimony. This attachment consists of several maps. The first page provides a map of Public Service's electric service territory in which the AGIS initiative will be implemented. Then the exhibit provides a separate map that reflects the area of the service territory where each technology (FAN, IVVO, FLISR or AMI) will be deployed. For the maps reflecting the deployment of FAN, IVVO and AMI, each map is color coded to reflect the anticipated deployment of each technology by geographic area and by year and/or quarter. The FLISR map only reflects the area in which it will be deployed by 2021 because the FLISR deployment is not expected to be segmented into geographic areas. The Company plans to deploy FLISR in a manner that is most beneficial to customers based on historical reliability performance, FAN availability, and overall system capabilities.

While these maps present the best currently-available information, it is possible that the deployment schedules may change somewhat as the Company progresses with its planning and approaches the deployment of each technology.

Q. WHY DOES THE COMPANY PROPOSE TO IMPLEMENT THE COMPONENTS OF THE AGIS INITIATIVE OVER A 2016-2021 TIMELINE, RATHER THAN OVER A SHORTER OR LONGER PERIOD?

A. The Company wants to deliver the benefits of an advanced grid to customers as soon as possible given the significant investment the Company will make in the AGIS initiative. The Company has a high degree of confidence that this time frame allows it to deliver the capabilities to customers in an expeditious manner while still allowing enough time for a successful build out of the various components of the initiative on the distribution system.

Q. HOW WILL THE COMPANY INTEGRATE THE COMPONENTS OF THE AGIS INITIATIVE IN BOULDER?

A. Many components of the current infrastructure that were implemented in Boulder as part of the SmartGridCity pilot project will be utilized as part of the AGIS initiative. Public Service will use the following existing infrastructure in Boulder: microwave technology, communication hut equipment, fiber optic cable and a portion of the communication equipment that is located in the Company's Boulder substations.

However, Public Service will replace the existing BPL network and AMI meters in Boulder. As I discuss above, BPL technology is no longer supported and replacement components have become increasingly difficult to acquire.

Therefore, this technology needs to be replaced and the FAN implementation will fulfill that role. The need to replace the existing meters in Boulder is due to the proprietary nature of the communications protocols that were used during the SmartGridCity pilot. The existing meters do not have and cannot be upgraded to include the necessary communication modules that allow today's advanced meters to communicate as part of the mesh network of the FAN.

Q. OVERALL, WHY IS THE COMPANY'S AGIS DEPLOYMENT PLAN REASONABLE?

A. The above timeline deploys the facilities, applications, and technologies of the AGIS initiative in a manner that allows customers to begin receiving the maximum amount of benefits by year-end 2021, balancing the desire to bring these benefits to customers with the need to plan for a large-scale deployment effort. Additionally, the proposed deployment timeline enables the Company to make prudent vendor selection decisions and to appropriately budget and plan for the implementations. The deployment plan also ensures that the necessary ground work is in place for each program prior to its implementation.

B. Overall AGIS Initiative Cost of Implementation

Q. CAN YOU PROVIDE AN OVERVIEW OF THE COSTS ASSOCIATED WITH ALL OF THE COMPONENTS OF AGIS?

A. Yes. The following chart summarizes the estimated costs for each component of the AGIS initiative over the next 5 years.

Table JDL-2-CPCN Projects Capital Costs 2016-2021 ($M)

Capital ($Millions)	2016	2017	2018	2019	2020	2021	Total 2016-2021
AMI	0.5	3.5	31.7	117.0	68.6	16.8	238.1
IVVO	0.0	18.2	21.7	20.1	18.5	18.9	97.4
FAN	0.4	10.0	13.0	13.0	2.7	0.2	39.2
IT	3.3	56.9	50.4	4.6	5.6	2.7	123.4
Total	**4.1**	**88.6**	**116.8**	**154.6**	**95.3**	**38.6**	**498.1**

Table JDL-3-CPCN Projects O&M Costs 2016-2021 ($M)

O&M ($Millions)	2016	2017	2018	2019	2020	2021	Total 2016-2021
AMI	0.4	1.4	2.5	3.5	2.0	0.4	10.2
IVVO	0.0	1.0	1.3	1.7	2.2	2.7	8.9
FAN	0.2	0.6	2.0	3.6	4.7	5.0	16.0
IT	0.1	4.6	7.0	5.8	5.8	5.8	29.2
Total	**0.7**	**7.7**	**12.8**	**14.6**	**14.6**	**13.9**	**64.3**

The costs reflected in the above charts are stated in 2016 capital expenditure dollars and do not account for escalations in costs due to inflationary pressures. The development of the costs associated with AMI, FAN, IVVO and IT are discussed in more detail in the Direct Testimonies of Company witnesses Messrs. Borchardt, Reimer, Nickell and Harkness.

Q. HOW DID THE COMPANY DETERMINE THE COST INPUTS FOR THE AGIS INITIATIVE?

A. A number of the components of the AGIS initiative involve purchasing field devises and installing the equipment. As a Company, we have a tremendous amount of experience installing devices on our system, and we relied on that experience to develop those estimates. For components of AGIS where we did not have significant experience, the Company relied on a Request for Information and Pricing ("RFx") that was submitted to potential AMI vendors, and benchmarking.

Q. WHY DID THE COMPANY CHOOSE NOT TO ENGAGE IN A DETAILED DESIGN OF THE BUILD OUT OF THE AGIS INITIATIVE IN ORDER TO DEVELOP MORE ACCURATE ESTIMATES?

A. Engaging in a detailed design for a project of this magnitude will cost millions of dollars. It is simply not necessary or prudent to engage in such an expensive process until the Commission determines these programs serve public convenience and necessity. It is typical for utilities to determine reasonable early-phase cost estimates prior to regulatory approvals through more cost effective tools, such as an RFx, benchmarking, and Company experience.

Q. HOW WERE THE COST INPUTS DETERMINED FOR IVVO, FLISR AND FLP?

A. These components of the AGIS initiative will be primarily implemented through the purchase and installation of equipment. The Company based its costs estimates on its own experience with installing and exchanging devices on our distribution system. These cost inputs are discussed in more detail in the Direct Testimony of Company witness Mr. Nickell.

Q. HOW WERE THE COST INPUTS DETERMINED FOR AMI, FAN, AND THE ASSOCIATED INFORMATION TECHNOLOGY?

A. The costs that were included for AMI, advanced meters, the mesh component of the FAN, and the associated IT were derived from an RFx that was sent out to several potential AMI vendors. The RFx requested both proposals for information and cost estimates. In addition to using the cost estimates in the

RFx, the Company also used benchmarking to confirm these inputs were reasonable as compared to other utilities that implemented similar technologies. Finally, because Public Service has less experience pricing these technologies, the Company included higher contingency estimates for these inputs. Company witness Mr. Borchardt discusses the RFx and the cost components of AMI more thoroughly; Company witness Mr. Reimer discusses the cost components of FAN and mesh network in more detail; and Company witness Mr. Harkness discusses the cost inputs for the associated IT systems.

Q. DOES THE COMPANY PLAN TO COMPLETE A REQUEST FOR PROPOSAL FOR THE AMI AND THE MESH COMPONENT OF THE FAN?

A. Yes. The Company sent a request for proposal ("RFP") in July of 2016 to the same potential AMI vendors that received its RFx. The Company expects that it will select a vendor in November 2016. At that time, the Company will be able to refine the cost inputs for AMI and the mesh components of the FAN. In addition, the Company will be able to provide more accurate IT cost inputs because once a vendor is selected the Company will know the specific IT systems it will be integrating as part of the AGIS initiative. This information will also reduce the contingencies for each of these AGIS components.

Q. DO YOU EXPECT A SIGNIFICANT CHANGE IN THE COST INPUTS AS A RESULT OF THE COMPLETION OF THE RFP?

A. No. The most significant change will likely be the reduction of contingencies because the potential AMI vendor will no longer be unknown. The actual cost inputs will be more accurate, but we do not expect them to differ significantly from the current cost inputs because the Company has taken a conservative approach to creating these costs and utilized the results of costs estimates from the RFx received earlier this year from the same potential AMI vendors to which the RFP was sent. Thus, we do not expect the inputs to change very much based on the results of the RFP. Given the stage we are at in the process and all of the information we have gathered to date, the Company believes the cost inputs included in this filing are reasonable.

C. <u>Program and Change Management Cost Inputs</u>

Q. DO YOU SUPPORT SPECIFIC COMPONENTS OF CPCN PROJECTS COSTS?

A. Yes, I support program and change management costs for AMI, IVVO, and the associated cost of the FAN, which are reflected in Attachment JDL-2 to my testimony.

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.

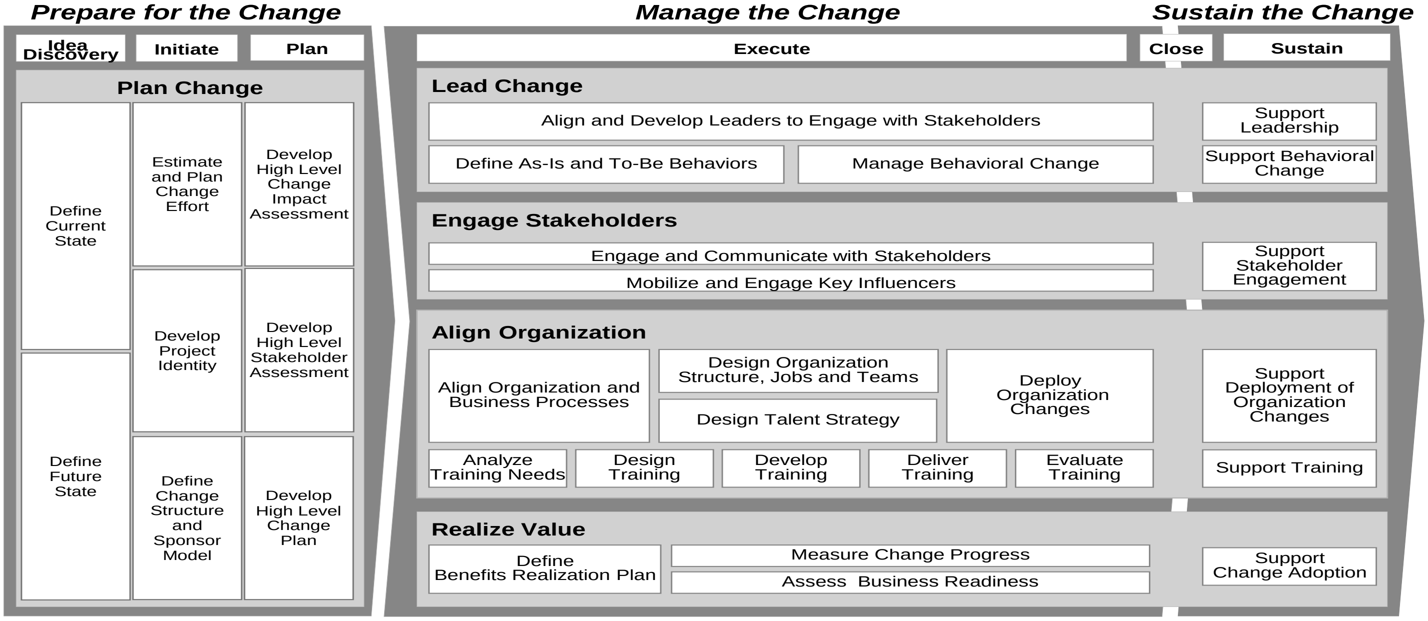
Q. PLEASE DESCRIBE THE COSTS ASSOCIATED WITH AGIS PROGRAM MANAGEMENT.

A. We have estimated the present value of program management costs for 2016-2021 to be approximately $15.9 million. Approximately $14.3 million of that estimate will be capitalized. These capital costs include engaging consultants and contractors throughout the development, deployment, and conclusion of the AGIS initiative. Approximately $1.6 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-4-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 HOW THE FIRST STEP OF PLANNING FOR THE CHANGE IS DEVELOPED?

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. The key process change may impact more than a 1,000 people or as little as less than ten 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 IS INVOLVED 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. The step will take several years to complete and it will be ongoing through the implementation of the AGIS initiative, which is expected to be 95% 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-5-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 departs. 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 $24.4 million. Approximately $14.6 million of that estimate will be capitalized. 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 $9.8 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 consists of 3% 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% 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. 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% 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.

Q. DID THE COMPANY DEVELOP CONTINGENCIES FOR PROGRAM AND CHANGE MANAGEMENT?

A. Yes. The contingency for both program and change management is $3.4 million in capital and $1.4 million for O&M, or approximately 12% of total costs. These contingencies are consistent with the estimated design, deployment, and operations of the other components of the initiative. They further reflect that it would be premature to invest substantial time in detailed design and engineering or to enter into materials and installation contracts before the Commission has determined that the CPCN Projects are needed and in the public interest. Until design and engineering are complete, contingencies are necessary to account for the unknowns that are likely to develop during the processes and through the installation and operations phase. The contingencies for program and change management are consistent with the contingencies proposed for the overall CPCN Projects.

V. ALTERNATIVES CONSIDERED

Q. DID THE COMPANY CONSIDER ALTERNATIVES TO THE AGIS INITIATIVE?

A. Yes. The individual technical alternatives to each individual CPCN Projects are discussed in detail in the Direct Testimonies of Company witnesses Messrs. Borchardt, Reimer, and Nickell. I discuss alternatives from the broader distribution system perspective.

Q. WAS TAKING NO ACTION ONE ALTERNATIVE TO PURSUING THE AGIS PROGRAMS?

A. Yes. From an overall system perspective, one alternative is to do nothing and maintain the current distribution system. However, Public Service has determined that "doing nothing" is not a viable option.

Q. WHY IS TAKING NO ACTION NOT CONSIDERED A VIABLE OPTION?

A. Public Service does not have the option to avoid investments in the distribution system because, as I describe above, the Company's current technology is no longer current in the industry and does not provide the functions needed for a modern utility. The communication technology currently employed is limited to supporting only the current infrastructure, and many of these communications networks have reached technical obsolescence. Additionally, the current system does not provide visibility into the grid that allows the Company to measure the influx of DER, which is anticipated to continue to increase at a rapid rate.

Further, as I describe earlier in my testimony, if the Company does not upgrade the current system equipment, it is expected that its SAIDI ranking for reliability performance will be below average by the year 2020. While Public

Service expects to maintain its current SAIDI response time, the industry expectation is becoming more stringent as more utilities implement advanced grids that can significantly increase SAIDI response times. Thus, by 2020 the acceptable SAIDI response time for first quartile performance is expected to be lowered by several minutes.

Finally, action is necessary or Public Service will not be able to meet customers' expectations. For example, as Company witness Ms. Jennifer B. Wozniak discusses in more detail, customers want the ability to access near real-time energy usage information in order to empower them to make decisions that affect their power usage. AMI metering is necessary to accomplish this objective.

Q. DID THE COMPANY CONSIDER DSM PROGRAMS AS ALTERNATIVES TO THE RELEVANT COMPONENTS OF AGIS?

A. Yes, but AGIS and other DSM programs are not mutually exclusive, and the technology of the AGIS initiative is necessary to some forms of DSM. For example, IVVO is an effective and efficient way to lower voltage on the electric grid because it creates benefits without customer action, versus relying on a subset of customers to voluntarily act to lower voltage at peak periods. As described above in more detail, the ability to monitor voltage across the entire grid enables lower voltage, which has a savings impact for all end-use customers. It can be likened to a 'wholesale level' of DSM.

Similarly, AMI meters are necessary to eventually facilitate near real-time usage information for customers and time-of-use rates. The technology we plan to employ through AGIS is necessary to these DSM efforts but does not preclude other efforts.

Q. DID PUBLIC SERVICE CONSIDER A SYSTEM-WIDE APPROACH TO UPGRADING THE DISTRIBUTION SYSTEM THAT DOES NOT REQUIRE THE IMPLEMENTATION OF INTEGRATED APPLICATIONS?

A. Yes. Ultimately each component of the AGIS initiative could have been completed through a stand-alone application. For example, the Company considered the use of independent sensors to measure voltage instead of AMI and advanced meters. However, AMI and advanced meters were selected over independent sensors because AMI is not a stand-alone system and, as I describe above, the advanced meters provide a multitude of benefits in addition to being voltage sensors. While independent sensors only perform the specific function of measuring voltage, advanced meters provided the capabilities necessary for the Company to achieve visibility into an individual customer's status. AMI and advanced meters constitute the only solution that provides the Company with the visibility into the status of the electric grid at the customer level.

Similarly, the components of IVVO, FLISR and FLP were chosen based on their ability to interact with each other and provide an integrated solution to address voltage and fault regulation and correction. Because independent components could not achieve the same outcomes, stand-alone options were discarded.

Q. DID PUBLIC SERVICE CONSIDER OTHER SYSTEM-WIDE APPROACHES?

A. Yes. We also evaluated the options of implementing only certain aspects of AGIS. However, as discussed above and in the testimony of Company witness Ms. Jackson, all of the components of the AGIS initiative essentially layer on top of each other with each one providing a solid foundation for the next. For example, the deployment of FAN, which will enable two-way communications with devices in the field, is a necessary foundational element that must be in place before AMI meters can be fully functional. Likewise, AMI meters must be in place to support applications like IVVO and FLISR. The ADMS provides the foundation for all of these elements. Consequently, our overall distribution advancement program consists of a strategically-developed set of components that are designed to function together.

Q. ARE THERE OTHER ALTERNATIVES THAT WOULD PROVIDE THE SAME RESULTS AS THE AGIS APPROACH?

A. No. As I describe above, the other available options are individual technologies that would not promote an integrated system. An ADMS provides a network model of the electric distribution grid that is essential to integrating each component of an advanced grid to work with each other. A FAN communication network keeps that model updated. To try and update the distribution grid with independent systems would create an environment where it would be virtually impossible to manually integrate the information gathered by each system. The components selected as part of the AGIS initiative are the correct components to bring Public Service's distribution grid into the future.

VI. CONCLUSION

Q. OVERALL, WHY DOES PUBLIC SERVICE BELIEVE THE AGIS INITIATIVE, AND MORE PARTICULARLY THE CPCN PROJECTS, IS THE RIGHT TECHNICAL STRATEGY FOR AN ADVANCED DISTRIBUTION GRID?

A. The Company has determined that the technology to implement the AGIS initiative has advanced to a point where it can be cost effectively deployed to achieve the needed capabilities and provide customer benefits that are necessary for us to be a competitive utility and meet customer needs. The electric industry is sitting on the edge of a sea change. It is not a change that can take place overnight and we need to start preparing for it now so that we that we can provide an advanced distribution grid that serves customer and system needs in the years to come.

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.