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

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

DIRECT TESTIMONY AND ATTACHMENTS OF STEVEN P. BERMAN

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

July 17, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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

SUMMARY OF THE DIRECT TESTIMONY OF STEVEN P. BERMAN

Mr. Steven P. Berman is Director, Regulatory Administration, for Public Service Company of Colorado ("Public Service" or the "Company"). In this position, he provides leadership, direction, and technical expertise related to regulatory processes and functions for Public Service.

In his Direct Testimony, Mr. Berman presents the Company's request for approval of an Advanced Grid Rider ("AGR") to recover costs related to the Company's Advanced Grid Intelligence and Security ("AGIS") initiative. In addition to introducing the other supporting witnesses, Mr. Berman begins by providing background on the AGIS initiative, which was previously described in and was, in part, the subject of a Certificate of Public Convenience and Necessity ("CPCN") proceeding ("AGIS CPCN Proceeding") before the Colorado Public Utilities Commission ("Commission"). Mr. Berman further underscores the importance of all AGIS projects, which include Advanced Metering Infrastructure ("AMI"), the Advanced Distribution Management System ("ADMS"), including the Geospatial Information System ("GIS"), Integrated Volt-VAr Optimization ("IVVO"), Fault

Location Isolation and Service Restoration ("FLISR"), the Field Area Network ("FAN"), and the Advanced Planning Tool ("APT").

Mr. Berman then identifies past Commission approvals associated with AGIS, including approval of the Unopposed Comprehensive Settlement Agreement (the "AGIS CPCN Settlement") in the AGIS CPCN Proceeding and of the Company's request to include certain AGIS capital and operations and maintenance ("O&M") costs in base rates in the Company's most recent Phase I electric rate case, filed in Proceeding No. 19AL-0268E ("2019 Electric Rate Case"). Together, these approvals underscore the need for and public interest in advancing the capabilities of the distribution grid. Mr. Berman notes, however, that the scale of the Company's upcoming investments in AGIS necessitate further consistent and dependable cost recovery through the AGIS implementation period.

Mr. Berman then provides an overview of the AGR, by which the Company seeks to recover the incremental capital additions and O&M associated with the AGIS projects for the years 2021-2025, and to amortize and recover both the costs that have been deferred as a result of the AGIS CPCN Settlement and the costs of Public Service legacy meters that have not yet been fully depreciated. He also describes the policy support for implementing the AGR, focusing on a number of considerations that include: replacing aging and obsolete facilities; reducing regulatory lag; diminishing the need for more frequent rate cases; reflecting prior support for the projects in the AGIS CPCN Settlement and rate case recovery to date; providing even further reporting and cost oversight on a structured basis; providing a cost-true-up mechanism to ensure costs charged to customers reflect actual investments; providing cost credits to customers as the Company realizes them; and avoiding bill impact spikes by smoothing cost recovery across each year of the AGIS implementation.

Mr. Berman next discusses the proposed components, structure, and mechanics of the AGR in more detail, and identifies the cost allocations and customer bill impacts associated with the AGR. He also explains the Company's proposal to provide detailed and robust annual AGR revenue requirement forecasts ahead of each calendar year, as well as true-up calculations after the end of each calendar year. These AGR reports will also include the same project detail already included in the Company's existing, post-CPCN AGIS reporting stemming from the AGIS CPCN Proceeding; however, the AGR reports will address all projects included in the AGR rather than limiting filings to the projects included in the CPCN. As such, this reporting will provide the Commission with routine, ongoing, and consistent insight into the AGIS project development and implementation. Finally, Mr. Berman supports the Company's request to defer the costs of undertaking this proceeding.

Overall, Mr. Berman recommends that the Commission approve the AGR consistent with the terms and conditions reflected in Attachment SPB-1 to his Direct Testimony; integrate the Company's reporting requirements from the AGIS CPCN Settlement into the AGR; authorize the 2021 forecasted AGR revenue requirement set forth in this filing; approve application of a five percent depreciation rate for AMI meters; approve the creation of a regulatory asset to recover the undepreciated balance of legacy meters; and authorize deferral of the expenses of this proceeding for potential future recovery.

BEFORE THE PUBLIC UTILITIES COMMISSION
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Attachment SPB-3	Class Cost Allocation, Rate Design, and Bill Impacts of the 2021 AGR Revenue Requirement

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2016 Phase II Electric Rate Case	Proceeding No. 16AL-0048E
2019 Electric Rate Case	Proceeding No. 19AL-0268E
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AGIS CPCN Proceeding	Proceeding No. 16A-0588E
AGIS CPCN Settlement	Unopposed Comprehensive Settlement Agreement approved in Proceeding No. 16A-0588E
AGR	Advanced Grid Rider
AMI	Advanced Metering Infrastructure
APT	Advanced Planning Tool
ARRR	Application for Rehearing, Reargument, or Reconsideration
Commission	Colorado Public Utilities Commission
CPCN	Certificate of Public Convenience and Necessity
FAN	Field Area Network
FLISR	Fault Location Isolation System Restoration
FLP	Fault Location Prediction
GIS	Geospatial Information System
HAN	Home Area Networks
IT	Information Technology
IVVO	Integrated Volt-VAr Optimization
NCP	Non-Coincident Peak
O&M	Operations and Maintenance
PSIA	Pipeline System Integrity Adjustment
Public Service or Company	Public Service Company of Colorado

Acronym/Defined Term	**Meaning**
S&F	Service and Facility
TCA	Transmission Cost Adjustment
WPR	Wildfire Protection Rider
Xcel Energy	Xcel Energy Inc.

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DIRECT TESTIMONY AND ATTACHMENTS OF STEVEN P. BERMAN

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Steven P. Berman. My business address is 1800 Larimer Street, Denver, Colorado 80202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Public Service. My position is Director, Regulatory Administration.

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 Director, Regulatory Administration, I provide leadership, direction, and technical expertise related to regulatory processes and functions for Public

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

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I present the Company's request for approval of an Advanced Grid Rider, or AGR, to recover costs related to the Company's AGIS initiative, and support the policy positions for adopting this recovery mechanism. I start by providing an overview of the AGIS initiative, including the background and history of the project and filings the Company has made to date. I then explain why the Company is proposing a rider at this time, including the customer benefits and Commission history that support the creation of the AGR and the recovery of costs through this rider mechanism. I then discuss the proposed structure and components of the rider, and the resulting impacts on customers' bills due to the AGR. Finally, I support the Company's request to defer the costs of making this filing and supporting this proceeding, for potential future cost recovery.

Q. ARE OTHER COMPANY WITNESSES FILING TESTIMONY?

A. Yes. In addition to my Direct Testimony, four Public Service witnesses are also providing Direct Testimony and accompanying attachments. These witnesses' respective topics are as follows:

Table SPB-D-1
Direct Testimony Witnesses

Witness	Area of Testimony
Deborah A. Blair, Director, Revenue Analysis	• Presents the annual revenue requirement associated with the AGIS initiative; • Explains what components of costs the Company is proposing to include in the AGR; and • Describes the AGR true-up process.
Laurie J. Wold, Senior Manager, Capital Asset Accounting	• Describes the categories of AGIS capital assets included for cost recovery through the AGR; • Proposes and supports a depreciation rate of five percent that will be applied to AMI meters; • Explains how Public Service will be compensated, through a shared asset adjustment, for its ownership of certain AGIS assets to the extent they support the initiatives of other Xcel Energy Inc. (“Xcel Energy”) operating companies; and • Supports Public Service’s proposal to create a regulatory asset to recover the undepreciated balance of legacy meters that will be replaced by AMI meters.
Chad S. Nickell, AGIS Delivery Lead for Distribution	• Explains the need for the AGIS initiative from a distribution system and customer perspective; • Supports the Company’s request for Distribution capital and O&M cost recovery for the AGIS initiative through the AGR; and • Explains and supports the implementation of capital and O&M forecasts for the Distribution components of the AGIS initiative.
Wendall A. Reimer, Director, AGIS Portfolio Delivery	• Explains the role of Business Systems and Information Technology (“IT”) in implementing the AGIS initiative; • Supports the Company’s request for Business Systems capital and O&M cost recovery for the AGIS initiative through the AGR; and • Explains and supports the implementation of, and capital and O&M forecasts for, the Business Systems components of the AGIS initiative.

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

A. Yes, I am sponsoring Attachments SPB-1 through SPB-3, which were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment SPB-1: Advanced Grid Rider (Illustrative Tariff Sheets);
- Attachment SPB-2: Summary of the Advanced Grid Rider; and
- Attachment SPB-3: Class Cost Allocation, Rate Design, and Bill Impacts of the 2021 AGR Revenue Requirement.

Q. PLEASE EXPLAIN PUBLIC SERVICE'S RECOMMENDATIONS IN THIS PROCEEDING.

A. Public Service specifically requests that the Commission issue an order:

- Authorizing Public Service to implement its proposed AGR consistent with the terms and conditions reflected in Attachment SPB-1 to my Direct Testimony;
- Authorizing the Company to integrate its reporting requirements from the AGIS CPCN Settlement into the AGR reporting requirements I outline in my Direct Testimony;
- Approve the 2021 forecasted AGR revenue requirement provided by Company witness Ms. Blair for implementation at the conclusion of this proceeding;
- Authorizing application of a five percent depreciation rate to AMI meters;
- Authorizing the creation of a regulatory asset to recover the undepreciated balance of legacy meters that will be replaced by AMI meters; and
- Authorizing the Company to defer the expenses incurred in connection with this proceeding into a regulatory asset without interest until they are included in the Company's next Phase I electric rate case.

II. OVERVIEW AND BACKGROUND OF THE AGIS INITIATIVE

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

A. In this section of my testimony, I first provide an overview of the AGIS initiative. I then provide a brief history of what has already been approved by the Commission with respect to the AGIS initiative projects, as well as the current regulatory status of this work. Finally, I provide an overview of the scope of the proposed AGR, culminating from the work performed and Commission filings and reports to date.

A. AGIS Overview

Q. PLEASE REMIND US, WHAT IS "AGIS"?

A. "AGIS" stands for Advanced Grid Intelligence and Security. The Company's AGIS initiative is a long-term strategic initiative that will transform the Company's electrical distribution business by enhancing security, efficiency, and reliability, enabling Public Service to safely integrate more distributed energy resources and improve customer products and services. The technical capabilities of the current grid are limited when compared to more advanced grid technologies that are available, and the overall system as presently configured is opaque—meaning the Company has little near real-time insight into the grid beyond the substation level. AGIS seeks to take advantage of developed and enhanced technology to increase grid reliability, transparency, efficiency, and access. The currently-planned AGIS projects consist of implementing existing advanced technology that will ultimately work together to support improved distribution technology as well as increased customer choice, energy management options, and savings opportunities.

Consistent with related initiatives by utilities around the country, it is the natural next step in the development of our distribution grid.

Q. WHAT ARE THE COMPONENTS OF AGIS?

A. AGIS is comprised of the following initial projects, which Company witnesses Mr. Nickell and Mr. Reimer discuss in detail:

- Advanced Metering Infrastructure (or AMI): AMI meters will support greater customer energy usage data and customer choice, more efficient outage management, and rate design proposals;
- Advanced Distribution Management System (or ADMS): ADMS provides an integrated operating and decision software and hardware system to support monitoring, controlling, and optimization of the electric distribution system, including the Company's project to update its Geospatial Information System (or GIS) that provides location and specification information about all physical assets that make up the distribution system;
- Integrated Volt-VAr Optimization (or IVVO): IVVO is an application that automates and optimizes distribution operation;
- Fault Location Isolation and Service Restoration (or FLISR): FLISR is an application that involves software and automated switching devices to decrease the duration and number of customers affected by any individual outage, which includes the Fault Like Protection ("FLP"), a subset application of FLISR that locates a faulted section of a feeder line;
- Field Area Network (or FAN): FAN is the communications network that will enable communications between existing infrastructure and the new advanced applications; and
- Advanced Planning Tool (or APT): APT is a spatial load forecasting tool to forecast how load and energy demands on the grid may change in the future.

Q. PLEASE REMIND US, WHY IS AGIS NEEDED?

A. As I mentioned, the technical capabilities of the current grid are limited when compared to more advanced grid technologies. Public Service's distribution system was originally designed to accommodate primarily a one-way flow of electricity and information from the utility to the customer with limited monitoring points. This design limits the amount of information and visibility that the Company has regarding the workings of the system and the customer experience beyond the distribution substation level. The system was also designed to rely heavily on manual and local control schemes to operate and lacks connectivity to easily share information between different portions and components of the system. The AGIS investments will provide Public Service with timely and accurate information about what is happening on all portions of the grid, from substations down to each individual customer's meter. These investments will also have the necessary automation and intelligence to address any problems quickly and efficiently. In addition, the AGIS investments will increase the customer experience by providing the foundation for new projects and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications. Building on prior AGIS-related filings before the Commission, Mr. Nickell provides additional detail and explains the benefits the AGIS initiative provides to customers.

Q. DID THE COMMISSION AND INTERVENING PARTIES AGREE THAT THE AGIS INITIATIVE WAS NEEDED?

A. Ultimately, yes. While each party's or the Commission's reasoning may differ from what the Company articulated or as I state above, ultimately the signatories to the AGIS CPCN Settlement (defined and discussed in further detail below) and the Commission's approval of the AGIS CPCN Settlement indicate they agree with the need for these projects.

B. AGIS History and Current Status

Q. HAS PUBLIC SERVICE PRESENTED ITS AGIS INITIATIVE TO THE COMMISSION PRIOR TO THIS APPLICATION?

A. Yes. The Company filed an application requesting a CPCN for certain AGIS projects in the AGIS CPCN Proceeding, Proceeding No. 16A-0588E, initiated on August 2, 2016. As part of its application and testimony in support of its request for the AGIS CPCN, the Company provided detailed support for its proposed "Grid CPCN" projects – AMI, IVVO, and the associated portion of the FAN – and also previewed certain other AGIS work that it was undertaking in the ordinary course of business – namely, ADMS (including the GIS), FLISR including FLP, and the private network portion of the FAN. The Company identified these projects as the foundational components of the AGIS initiative.

Q. PLEASE PROVIDE AN OVERVIEW OF THE AGIS CPCN PROCEEDING.

A. Public Service filed the Direct Testimony and attachments of eight witnesses to address all facets of the AGIS initiative. Three witnesses provided an overview and the key objectives of AGIS, a quantitative cost-benefit analysis, and the Company's customer education plan; and five technical witnesses supported the technical strategy for AMI, IVVO, FAN, ADMS, FLISR, FLP, and IT implementation and integration. Eleven parties intervened and conducted robust discovery. The Company responded to 1,434 discovery requests including subparts. Eight intervenors filed Answer Testimony via ten witnesses, representing a wide range of interests. The Company filed detailed Rebuttal Testimony from five witnesses. Subsequently, after extensive negotiation, the parties to the AGIS CPCN

Proceeding ultimately reached a settlement and filed the AGIS CPCN Settlement that was approved by the Commission in Decision No. C17-0556 (mailed July 25, 2017).

Q. WHAT DOES THE COMMISSION'S APPROVAL OF THE AGIS CPCN SETTLEMENT MEAN FOR THIS FILING?

A. The AGIS CPCN Settlement provided a CPCN for certain AGIS projects, allowing the Company to move forward with project implementation and deferral of certain costs, subject to regular reporting requirements, prudence reviews of future costs in cost recovery requests, and other requirements. I discuss the terms of the AGIS CPCN Settlement further below, and Mr. Nickell and Mr. Reimer provide additional support for the prudent implementation of all the AGIS projects the Company seeks to include in the AGR.[1]

Q. DID PUBLIC SERVICE RECEIVE APPROVAL FOR ANY AGIS-RELATED WORK AFTER THE CPCN SETTLEMENT AND BEFORE ANY COST RECOVERY?

A. Yes. One of the conditions of the AGIS CPCN Settlement required the Company to file an application with the Commission with a plan to activate the Home Area Network ("HAN") capability within the AMI meter. The Company filed its HAN application on March 30, 2018, and the plan was approved by Commission Decision No. R18-0590 (mailed July 24, 2018), in Proceeding No. 18A-0194E.

[1] The following terms addressed in the AGIS CPCN Settlement are not relevant to this proceeding, and therefore are not discussed in testimony: Residential Energy Time of Use Rate; Remote Disconnection/Reconnection, and Customer AMI Opt-Out.

Q. WHAT ACCOUNTING TREATMENT WAS APPROVED FOR THE CAPITAL AND O&M COSTS FOR PROJECT DEPLOYMENTS PURSUANT TO THE AGIS CPCN SETTLEMENT?

A. Under the AGIS CPCN Settlement, the Company is permitted to apply deferred accounting treatment to O&M expenses and any capital costs placed in service for the Grid CPCN projects until those costs are included in base rates. However, for the costs for deployment of AMI and associated infrastructure, the deferral mechanism applies only to the extent such costs are not included in the existing Service and Facility ("S&F") charge.

Consequently, deferred accounting mechanisms are available for each project (AMI, IVVO, and associated FAN); one for deferred capital investment and one for O&M expenditures. The deferral of these costs is permitted to continue beyond the first rate case. In the event the sum of the two capital investment deferrals totals $50 million or greater, the Company will begin to assess an interest rate equal to the Company's after-tax WACC on the balance of the relevant capital assets placed in service, with the resulting interest added to the deferred account, until such amounts are included in base rates and an amortization of the deferred balance is initiated.

Q. IS THE COMPANY CURRENTLY RECOVERING A PORTION OF AGIS COSTS THROUGH BASE RATES?

A. Yes. Public Service filed its 2019 Electric Rate Case on May 20, 2019, in Proceeding No. 19AL-0268E, seeking recovery of AGIS plant-in-service through the end of 2019, as well as associated O&M expenditures. Per Decision No. C20-

0096 in that proceeding, and subsequently Decision No. C20-0505 resulting from the Application for Rehearing, Reargument, or Reconsideration ("ARRR"), the Company was authorized to recover, in base rates, plant-in-service through August 2019 and O&M including known and measurable adjustments to the 2019 calendar year level. As I discuss later in my testimony, costs being recovered through base rates will not be included in the AGR. In turn, Ms. Blair explains the amount of AGIS costs currently included in base rates and how those amounts are subtracted from the AGR revenue requirement.

Q. PLEASE DISCUSS THE REPORTING REQUIREMENTS AGREED TO IN THE AGIS CPCN SETTLEMENT.

A. As part of the AGIS CPCN Settlement, the Company agreed to file semi-annual reports regarding project milestones, scope, costs, and the status of the CPCN projects. As such, the Company provides an annual forecast report filed in October with the forecast for the upcoming calendar year, and an annual actuals report filed in May of each year containing the actuals from the previous year.

Specifically, the October forecast reports provide: (1) a forecast summary for the upcoming year; (2) a full-term business plan, including the scope of work for the CPCN projects; (3) forecasted O&M and capital expenditures for the upcoming year; (4) parent project numbers including details of additions and closings of parent project numbers; and (5) planning and implementation of customer education surrounding the CPCN projects.

The May actuals reports provide: (1) a business plan overview of the previous year's progression; (2) project milestones and overall project status;

(3) planning and implementation of customer education; (4) the final cost per AMI meter, excluding installation and taxes, and the final cost per AMI meter including installation and taxes; (5) the total AMI meters installed each year; (6) O&M expenses incurred and actual capital spend for the previous calendar year; (7) a comparison of the forecasted spend to the actual O&M and capital spend; (8) comparison of total spend to the overall budget; and (9) a cost summary.

Q. HAS THE COMPANY BEEN UNDERTAKING THESE REPORTING REQUIREMENTS?

A. Yes, the Company has kept the Commission informed through its semi-annual reports. To date, the Company has filed three forecast reports (for the years 2018, 2019, and 2020) and three actuals reports (for the years 2017, 2018, and 2019).

Q. HAS THE COMPANY IDENTIFIED ANY CHANGES IN THE PLANNED IMPLEMENTATION TIMELINE OF THE AGIS INITIATIVE COMPARED TO THE AGIS CPCN TIMELINES?

A. Yes. While implementation is generally on schedule, the Company has identified changes to the planned implementation timeline that are discussed in detail by Mr. Nickell and Mr. Reimer. At a high level, the Company completed installation of 13,000 AMI meters in support of the IVVO project in 2019 as contemplated by the AGIS CPCN Settlement. Full deployment was scheduled to begin in 2020 but has been delayed to the end of the second quarter of 2021 due to a change in the meter vendor, as discussed by Mr. Nickell. Despite this start date delay, the Company still anticipates completing full deployment of all AMI meters in its electric service territory by 2024, as contemplated by the AGIS CPCN Settlement. The

Company is currently working with the parties to the AGIS CPCN Settlement to amend the settlement agreement to reflect this change in the timeline.

Q. HAS THE COMPANY IDENTIFIED ANY ADDITIONAL CHANGES FOR PROJECTS PREVIOUSLY APPROVED BY THE COMMISSION?

A. Yes. As discussed in detail by Mr. Reimer, in relation to the HAN, technology advancement has prompted a move away from ZigBee[2] and toward Wi-Fi to better serve customers. Wi-Fi has become prevalent among customers, such that a move to Wi-Fi from ZigBee better facilitates customer use of the HAN and avoids the need for additional investment. Again, the Company is currently working with the parties to the HAN application to explain this change, which is also discussed in more detail in this filing.

Q. WHAT IS THE CURRENT IMPLEMENTATION PLAN FOR AGIS?

A. The current implementation plan, as discussed in detail by Mr. Nickell and Mr. Reimer, is illustrated in Table SPB-D-2, below.

[2] ZigBee is a low-power, short-distance wireless communication technology.

Table SPB-D-2
Timeline of Key Events in AGIS Implementation

<table>
<tr><th></th><th>2019</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>2024</th><th>2025</th></tr>
<tr><td>AMI</td><td>13,000 meters installed to support IVVO</td><td></td><td colspan="4">Install 1.6 million AMI meters starting at the end of the second quarter of 2021 and continuing through 2024</td><td></td></tr>
<tr><td>ADMS</td><td>First deployment (core functions enabling IVVO) complete</td><td>Second deployment (go-live) to occur in fourth quarter</td><td colspan="5">ADMS functionality will continue to expand as IVVO and FLISR functions are added to the system</td></tr>
<tr><td>IVVO</td><td colspan="5">Install 974 capacitors, 4,350 secondary static VAr compensators and 121 Load Tap Changers (2018 – 2023)</td><td></td><td></td></tr>
<tr><td>FLISR</td><td colspan="7">Install 592 field devices (reclosers, switches, and substation relays) on approximately 205 feeders from 2016 – 2025)</td></tr>
<tr><td>FAN - WiSUN</td><td colspan="6">WiSUN devices installed in advance of AMI meters and field devices and optimized as the network becomes operational</td><td></td></tr>
<tr><td>FAN - Private Network</td><td></td><td>Replaced WiMAX with cellular data</td><td colspan="5">TBD

Analysis for long-term private network expected to be complete by end of 2020</td></tr>
<tr><td>APT</td><td></td><td>Deploy in December</td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

C. Overview of the AGR

Q. WHAT IS THE SCOPE OF THE PROPOSED AGR?

A. The Company proposes the AGR to support the implementation of the foundational components of the AGIS initiative. This is intended to be a limited rider that will cover certain capital additions and incremental O&M, beginning with approval of this AGR in 2021 and continuing through the true-up process for 2025 when the foundational portions of the AGIS initiative are in place.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROJECTS THE COMPANY IS SEEKING TO INCLUDE IN THE PROPOSED AGR.

A. The projects eligible for recovery under the AGR include the following, as discussed in more detail by Mr. Nickell and Mr. Reimer:

- Projects included in the CPCN
  - IVVO
  - AMI and HAN
  - WiSUN portion of the FAN supporting IVVO and AMI
- Projects not included in the CPCN
  - ADMS (including GIS)
  - FLISR and FLP
  - Private network portion of the FAN
  - APT

Q. DOES THE COMPANY SEEK TO RECOVER ANY OTHER COSTS THROUGH THE PROPOSED AGR?

A. Yes. Through AMI, the Company will be replacing some legacy meters that have not been fully depreciated. The Company proposes to recover the remaining book value of legacy meters and deferred costs under the AGIS CPCN Settlement prior to implementation of the AGR through creation of a regulatory asset and amortization, as discussed by Company witness Ms. Wold.

Q. WHY IS THE COMPANY INCLUDING THE ADVANCED PLANNING TOOL IN THE SCOPE OF THE AGR?

A. As described by Mr. Nickell in more detail (and supported by Mr. Reimer), the APT, known as “LoadSeer,” is a forecasting and planning tool that will enable Public Service to efficiently expand its distribution planning capabilities to incorporate distributed energy resources, enhance its load forecasting capabilities, and better integrate and align with the Company's other planning tools and processes. The APT is part of the overall advancement of the distribution grid and aligns with the foundational AGIS projects.

Q. PLEASE IDENTIFY THE TYPES OF COSTS ASSOCIATED WITH THESE PROJECTS THAT THE COMPANY SEEKS TO INCLUDE IN THE AGR.

A. The Company seeks to include capital additions; related costs such as Accumulated Deferred Income Taxes, depreciation, and taxes; and O&M expense for the projects identified, incremental to any amounts included in base rates. Mr. Nickell and Mr. Reimer provide details on each of the AGR's projects and associated costs in their Direct Testimonies, and Ms. Blair presents the Company's forecasted revenue requirement associated with the AGR. In particular, Ms. Blair details the 2021 forecasted revenue requirement the Company requests to implement in 2021 upon approval of the AGR, and provides illustrative detail for the other years' revenue requirements.

Q. YOU STATED THAT ONLY INCREMENTAL COSTS WILL BE RECOVERED THROUGH THE PROPOSED AGR. PLEASE IDENTIFY THE AMOUNTS THAT ARE ALREADY INCLUDED IN BASE RATES.

A. As discussed by Ms. Blair, $19.25 million of total revenue requirement for AGR-eligible projects was included in base rates during the Company's 2019 Electric Rate Case, subject to the final Commission decision in that case.[3] To the extent such amounts are included in base rates, they are subtracted from the overall

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[3] The deadline to file ARRR to Decision No. C20-0505 (mailed July 14, 2020) in Proceeding No. 19AL-0268E is August 3, 2020.

revenue requirement in the AGR. Ms. Blair explains the derivation of the amount included in base rates and shows the reduction of this amount from the overall AGR revenue requirement.

Q. PLEASE PROVIDE AN OVERVIEW OF THE AGIS COSTS THE COMPANY PROPOSES TO INCLUDE IN THE AGR.

A. Table SPB-D-3 identifies the capital additions actually incurred in prior years or forecasted in future periods and Table SPB-D-4 identifies the O&M costs forecasted for projects eligible to be recovered through the AGR. These costs are discussed in greater detail by Mr. Nickell and Mr. Reimer in their Direct Testimonies. These costs illustrate total AGIS costs, before any offset for the revenue requirement included in base rates.

Table SPB-D-3
AGR Capital Additions
(Dollars in millions)

Project	2019	2020	2021	2022	2023	2024	2025
AMI	59.19	45.61	107.86	102.74	91.07	33.72	0.24
ADMS	45.86	27.25	0.16	0.00	0.00	0.00	0.00
IVVO	29.81	30.20	24.98	22.87	12.90	1.75	0.00
FLISR	15.54	6.90	6.22	6.47	9.15	6.54	6.60
FAN	13.87	5.66	40.35	9.36	21.41	2.28	0.13
Other	0.42	5.36	2.79	3.19	10.90	4.50	0.00
Total	**164.69**	**120.98**	**182.36**	**144.63**	**145.43**	**48.79**	**6.97**

Table SPB-D-4
AGR O&M Costs
(Dollars in millions)

Project	2021	2022	2023	2024	2025
AMI	9.25	6.12	7.72	8.12	8.73
ADMS	2.25	2.24	3.43	3.56	2.24
IVVO	0.83	0.58	0.18	0.19	0.20
FLISR	0.37	0.64	0.68	0.70	0.64
FAN	0.52	0.56	0.59	0.60	0.32
Other	2.50	2.55	1.59	1.59	1.37
Total	**15.70**	**12.68**	**14.19**	**14.75**	**13.51**

Q. PLEASE PROVIDE AN OVERVIEW OF THE FORECASTED AGR REVENUE REQUIREMENT FROM 2021 THROUGH 2025.

A. In Table SPB-D-5 below, I provide a summary overview of the forecasted revenue requirement over the period of 2021 through 2025 for the AGR. Ms. Blair provides the detailed revenue requirement calculation in Attachment DAB-1. As Ms. Blair discusses in her Direct Testimony, the 2021 costs are presented as the Company's forecasted AGR revenue requirement for 2021, whereas the costs for other years are illustrative only. In November of each year, the Company would provide forecasted revenue requirements for the following calendar year, as I describe later in my Direct Testimony.

Table SPB-D-5
Forecasted AGR Revenue Requirement 2021 – 2025
(Dollars in millions)

Description	2021	2022	2023	2024	2025
Total Revenue Requirement	71.96	87.88	102.00	108.61	117.78
Amount in Base Rates	(19.25)	(19.25)	(19.25)	(19.25)	(19.25)
Net Revenue Requirement	**52.71**	**68.63**	**82.75**	**89.35**	**98.53**

Q. HOW DOES THE COMPANY SUPPORT THESE COSTS AND RIDER RECOVERY IN THIS FILING?

A. Mr. Nickell and Mr. Reimer discuss the specific projects and activities that will be eligible for recovery through the AGR, and present detailed supporting budget and project planning information. More specifically, Mr. Nickell and Mr. Reimer present the support for the work being done based on the work by their respective business areas – Distribution work completed by Mr. Nickell's area, and Business Systems (or IT) work completed by Mr. Reimer's area. Mr. Nickell and Mr. Reimer provide further support for the current division of AGIS project costs between their business areas, in order to support the budgeted costs for each overall AGIS project.

Q. HOW IS THE COMPANY ULTIMATELY MANAGING AGIS COSTS?

A. Public Service's budgets are generally managed by business area on a working basis. Further, some AGIS projects are primarily the responsibility of Distribution, while others are the primary responsibility of Business Systems. However, AGIS is a single overall initiative on which the business areas work closely together, and the total costs of the AGIS initiative are reviewed as a whole. This is why I present total AGIS initiative and per-project costs above, and why Mr. Nickell (on Distribution-led projects) or Mr. Reimer (on Business Systems-led projects) compare current forecasts for Grid CPCN projects to CPCN estimates according to the total costs of each project.

Q. IS THE COMPANY PROVIDING ANY OTHER SUPPORT FOR THE TOTAL COSTS OF THE PROJECT?

A. Yes. As I previously noted, Ms. Wold and Ms. Blair support the capital asset accounting for the AGIS initiative and revenue requirements, respectively, for the AGR flowing from the project costs identified by Mr. Reimer and Mr. Nickell. In total, combined with the additional information I provide in my Direct Testimony, these witnesses provide robust support for the entire AGR.

III. POLICY RATIONALE FOR APPROVING AN ADVANCED GRID RIDER

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

A. In this section of my Direct Testimony, I explain the public policy considerations that support approval of the AGR. Further, I explain why it is appropriate for the Commission to approve both the AGR and the Wildfire Protection Rider ("WPR") that the Company recently filed.

Q. WHAT STANDARDS AND POLICY DRIVERS HAS THE COMMISSION CONSIDERED IN APPROVING RIDERS IN THE PAST?

A. The Commission has broad ratemaking authority, under which it can and has approved multiple utility riders in the past. It is my understanding that the Commission has never codified specific standards for rider approval. In certain prior decisions, the Commission has articulated three criteria for determining if a rider is appropriate: (1) the costs to be recovered are volatile; (2) the volatile cost changes subject to recovery are large in magnitude; and (3) the volatile cost changes are beyond the utility's control.[4]

More recently, however, the Commission has declined to strictly follow this three-pronged test and has instead looked to other policy considerations.[5] Policy considerations such as the public interest in addressing obsolete and aging

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[4] *See* Application No. 37739, Decision No. C86-1529 (mailed Nov. 10, 1986) (applying the three-pronged test to a cost adjustment application by a telecommunications provider); Proceeding No. 09AL-837E, Decision No. C10-1119 at 8-11 (mailed Nov. 9, 2010) (applying the three-pronged test in approving a purchased capacity cost adjustment); Proceeding No. 12AL-1268G, Decision No. R13-1307, n. 101 (mailed Oct. 22, 2013); Proceeding No. 17AL-0429G, Decision No. R18-0014 at 31 ¶ 87 (mailed Jan. 8, 2018).

[5] Proceeding No. 17AL-0429G, Decision No. C18-0311 at ¶ 32 (mailed May 3, 2018) ("The Commission is reluctant to set forth a policy on cost adjustments and rate mechanisms in the narrow context of this rate proceeding for a single natural gas utility. We also conclude that such a policy is not required.").

facilities, urgency and need to accelerate the proposed activities, reduction in regulatory lag, providing a greater degree of flexibility and response to changing costs, and a reduction in the number of general ratemaking cases are all factors the Commission has found to justify rider cost recovery in the recent past.[6]

Q. HOW DOES APPROVAL OF THE AGR ALIGN WITH THESE VARIOUS POLICY CONSIDERATIONS?

A. While the Company is not advocating that the Commission adopt any standard of general applicability in this proceeding, authorizing recovery of the requested AGIS costs through a rider is supported by many of the policy considerations the Commission has historically looked to in approving riders in the past.

Beginning with the three-pronged test, the second prong related to the magnitude of the costs is most applicable to the AGIS initiative. The investments made as part of the AGIS initiative will modernize and transform every aspect of Public Service's distribution system. Once complete, these investments will enhance the security, reliability, and resiliency of the system as well as provide energy savings, greater customer choice, and allowance for increased integration of distributed energy resources on the grid. This transformation requires extensive work throughout Public Service's distribution system, such as the replacement of 1.6 million electric customer meters. As a result, the costs for AGIS are considerable and the Company is forecasting that AGIS will cost roughly $800 million over the next five years. Once it is fully in-service AGIS will represent

[6] *See* Proceeding No. 17AL-0429G, Decision No. R18-0014 at 31-32 ¶¶ 88-90 (mailed Jan. 8, 2018) (citing Application No. 32603, Decision No. C80-1592 at 4 (mailed Aug. 12, 1980)).

almost 8 percent of total Company net plant. As such, even with some cost recovery in base rates, the magnitude of AGIS investments warrants the utilization of a rider to allow timely recovery of these costs.

Q. WHAT OTHER POLICY CONSIDERATIONS ARTICULATED BY THE COMMISSION SUPPORT THE USE OF RIDER RECOVERY FOR AGIS COSTS?

A. In addition, several of the other factors previously outlined by the Commission also weigh in favor of approving the AGR, including:

- Public interest in replacing aging and obsolete facilities;[7]
- Reduction of regulatory lag associated with other forms of cost recovery;[8] and
- Minimizing the need for more frequent general rate cases.[9]

I discuss each of these factors in greater detail below, as well as other public policy considerations that support approval of the AGR.

Q. PLEASE DISCUSS HOW THE AGIS INITIATIVE ADDRESSES THE NEED TO REPLACE AGING AND OBSOLETE FACILITIES.

A. As previously described in the AGIS CPCN Proceeding, a majority of Public Service's legacy distribution system is based on a one-way flow of information. This means that, beyond the distribution substation, the Company has little real-time insight into the workings of the distribution system relating to outages, voltage levels experienced by the customer, and the amount of distributed energy

[7] Proceeding No. 17AL-0429G, Decision No. R18-0014, at 32 ¶ 90 (mailed Jan. 8, 2018).
[8] Proceeding No. 17AL-0429G, Decision No. R18-0014, at 31-32 ¶ 88 (mailed Jan. 8, 2018) (citing Application No. 32603, Decision No. C80-1592 at 4 (mailed Aug. 12, 1980)).
[9] Proceeding No. 17AL-0429G, Decision No. R18-0014 at 32 ¶ 90 (mailed Jan. 8, 2018).

resources on the system. In addition, the current system relies heavily on technology that requires manual and local controls and has limited connectivity or exchange of information between different parts of the system. These limitations impact Public Service's ability to timely respond to outages, manage voltage levels at a customer premise, and plan for the expected increase in installation of distributed energy resources. As discussed in greater detail by Mr. Nickell and Mr. Reimer, AGIS will address these current limitations through implementation of current technologies that enhance the overall security, reliability, and resiliency of the system.

The existing distribution system also limits Public Service's ability to provide customers timely access to energy usage information. The AMI meters that are being deployed as part of the AGIS initiative address this need by providing timely and detailed energy usage data that allows customers greater choices to manage their electricity usage and thus their energy costs. At its core, the AGIS initiative is a set of projects that work together to create a more modern, intelligent, and advanced distribution grid for the benefit of Public Service's customers.

It is important to note that the Company's request for a CPCN and the unopposed comprehensive settlement approved by the Commission in that proceeding were also premised on these system needs and the value of the Grid CPCN components of the AGIS initiative to address them.

Q. IS PUBLIC SERVICE'S AGIS INITIATIVE CONSISTENT WITH BROADER NATIONAL TRENDS?

A. Yes. Public Service's AGIS initiative is consistent with broader industry needs to modernize and address aging distribution infrastructure nationwide. The Department of Energy's Smart Grid System Report explained:

> Our [country's] electric infrastructure is aging and it is being pushed to do more than it was originally designed to do. Modernizing the grid to make it "smarter" and more resilient through the use of cutting-edge technologies, equipment, and controls that communicate and work together to deliver electricity more reliably and efficiently can greatly reduce the frequency and duration of power outages, reduce storm impacts, and restore service faster when outages occur. Consumers can better manage their own energy consumption and costs because they have easier access to their own data. Utilities also benefit from a modernized grid, including improved security, reduced peak loads, increased integration of renewables, and lower operational costs.[10]

The AGIS initiative is consistent with these national goals to modernize the distribution system. And like the Department of Energy, Public Service is finding that customers are demanding more optionality, more control over their energy usage, better outage management, and communications that can only be provided through the deployment of advanced distribution system technologies.

Q. HOW DOES APPROVAL OF THE PROPOSED AGR RESULT IN A REDUCTION IN REGULATORY LAG?

A. The AGR allows the Company to timely recover the costs associated with implementation of AGIS on an annual basis, subject to annual prudence reviews as discussed later in my Direct Testimony, rather than delaying recovery until the

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[10] *Grid Modernization and the Smart Grid*, U.S. DEP'T OF ENERGY, *available at* https://www.energy.gov/oe/activities/technology-development/grid-modernization-and-smart-grid (last visited June 28, 2020).

Company's next rate case. This includes recovery of costs that are being deferred currently under the AGIS CPCN Settlement. It is important that the Company is able to recover its costs associated with the AGIS initiative on a timely basis, to facilitate the implementation of this important and transformative project. Further, the AGR will allow for a more holistic review of all AGIS costs on a regular (semi-annual) basis, rather than every few years in a single rate case (which I discuss in more detail below).

Q. HOW DOES APPROVAL OF RIDER RECOVERY FOR AGIS COSTS REDUCE THE NEED FOR MORE FREQUENT GENERAL RATE CASES?

A. As noted earlier, Public Service recently completed its 2019 Electric Rate Case in which the Company sought recovery of certain costs of the AGIS initiative. However, this most recent rate case only covered a small portion of AGIS costs, as the bulk of the AGIS investments will be made in the next several years (such as the mass deployment of AMI meters starting in 2021). The proposed AGR will enable Public Service to bridge the gap between general rate cases by enabling recovery of costs for this significant, but narrow, category of Public Service's investments during the most cost-intensive implementation phase. In the absence of such recovery, Public Service's AGIS investments would require the need for more frequent rate cases, which are both costly and resource-intensive.

Q. APART FROM THE FACTORS PREVIOUSLY OUTLINED BY THE COMMISSION, ARE THERE OTHER POLICY REASONS THAT SUPPORT RECOVERY OF AGIS COSTS THROUGH THE PROPOSED RIDER?

A. Yes. There are at least five:

1. Prior support for undertaking the Grid CPCN projects in the AGIS CPCN Proceeding;

2. More regular and routine oversight of costs and cost recovery through the proposed reporting and true-up processes;

3. The annual true-up ensures customers pay no more or less than the actual costs of these important projects;

4. Providing customers with shared asset credit as they are realized; and

5. Smoothing out the rate impacts of AGIS implementation.

Q. PLEASE EXPLAIN THE FIRST ADDITIONAL CONSIDERATION – APPROVAL TO PROCEED WITH GRID CPCN PROJECTS AS A RESULT OF THE CPCN.

A. Public Service recognizes that while the CPCN was not a prudence determination on the expenditures over the amount approved in that proceeding, the AGIS CPCN Settlement and Commission approval of that settlement do evidence broad-based support in Colorado for advancement of the overall AGIS initiative. As such, rider recovery is more appropriate than a general rate proceeding to address implementation of this limited set of AGIS investments.

Q. PLEASE EXPLAIN THE SECOND ADDITIONAL CONSIDERATION – REGULAR REPORTING, TRUE-UPS, AND OVERSIGHT.

A. In contrast to standard rate case recovery, where the Commission and stakeholders are only able to examine the costs and implementation of a project at a single point in time, the proposed AGR provides the opportunity for greater oversight through semi-annual reporting and an annual cost true-up.

As discussed in Section IV below, Public Service proposes to modify the current semi-annual reports required by the AGIS CPCN Settlement into a forecasted revenue requirement filing on or before November 15 of each year and then an annual true-up report on or before April 15 of each year. This April AGR report will also provide updates on the same topics and metrics that are currently provided by the Company in its semi-annual reports. These proposed AGR reports will provide information about both the AGIS CPCN projects as well as the AGIS projects that are not currently subject to any reporting requirements (i.e., ADMS, FLISR, FLP, and APT).

As a result, the proposed AGR reporting will provide the Commission and stakeholders greater insight into all aspects of Public Service's AGIS implementation and associated costs. It will operate much like the Pipeline System Integrity Adjustment ("PSIA"), which over time has proven to be an effective means of keeping Commission Staff apprised of forecasted and actual system investments, and a forum for discussion of any concerns on an annual basis. And the Company anticipates the AGR expiring following completion of the true-up for 2025, reflecting that its purpose is to support the initial implementation of the major components of the AGIS initiative.

Q. IS THIS FACTOR ALSO CONSISTENT WITH THE COMMISSION'S ORDER IN ITS DECISION APPROVING THE AGIS CPCN SETTLEMENT?

A. Yes. In paragraphs 35 and 36 of Decision No. C17-0556 approving the AGIS CPCN Settlement, the Commission outlined that Public Service has the burden to present "robust testimony with accompanying exhibits" to justify both base amount expenditures and amounts in excess of the base for both AMI and IVVO. This filing, along with the additional, routine annual reporting processes the Company proposes here, offer the Commission and interested parties greater opportunity to observe and test the prudence of the specific AGIS investments on a year-over-year basis. Building on the current reporting contemplated by the AGIS CPCN Settlement, the Commission would also be apprised each year of Public Service's forecasted plans and costs for each of the initial AGIS projects. Public Service will then follow-up with actual results and any changes that are made in the design and associated costs of the AGIS projects as they are deployed. This greater oversight applies not only to the CPCN projects but to all of the AGIS foundational projects and to the actual process for cost recovery. This additional reporting allows a more frequent and granular view of each stage of the implementation and the costs of each of these projects.

Q. PLEASE EXPLAIN THE THIRD ADDITIONAL CONSIDERATION – RECOVERY LIMITED TO ACTUAL COSTS ON A YEAR-OVER-YEAR BASIS.

A. The proposed annual true-up of costs in April of each year ensures that the Company recovers from customers the actual costs prudently incurred under its AGR. The true-up corrects any differences between forecasted and actual costs without delay. This process will facilitate transparency, encourage exchange of information, and provide greater Commission and stakeholder oversight into the implementation of AGIS.

Q. WHAT ARE THE CHANCES THAT THE ACTUAL COSTS DIFFER FROM THE FORECASTED COSTS INCLUDED IN THE AGR?

A. Without a doubt they will be off to some degree, particularly due to the shared asset nature of some of the costs for AGIS as I discuss below. I do expect the costs of the overall initiative to be in line with current forecasts in most respects. It should be noted, however, that the value of the AGR is, in part, to take into consideration both the cost and revenue sides of the equation. Uncertainty on both costs and revenue collections would ultimately be trued up, with the prudence of specific costs evaluated annually such that customers would pay no more and no less than what is approved by the Commission.

Q. TO WHAT EXTENT WILL AGIS COSTS CONTINUE TO BE RECOVERED THROUGH THE AGR AFTER AN AGIS PROJECT IS PLACED IN SERVICE?

A. The purpose of the AGR is to allow timely recovery of the costs associated with the initial implementation of the AGIS projects. Once a particular AGIS project is placed in service and has gone through the annual prudence process, Public Service will move recovery of the costs related to the project from the AGR to base rates in the Company's next rate case filing. As such, Public Service intends for the AGR to be a rider of limited duration for a specific but necessary purpose – the completion of the initial AGIS projects.

Q. PLEASE EXPLAIN THE FOURTH ADDITIONAL CONSIDERATION – PROVIDING CUSTOMERS WITH SHARED ASSET CREDITS AS THEY ARE REALIZED.

A. Because Colorado was ahead of other Xcel Energy jurisdictions with respect to the AGIS initiative, the costs in the CPCN did not fully contemplate sharing the assets with other jurisdictions. However, other Xcel Energy operating companies are planning to deploy AMI technology and will benefit from the AMI head-end software recorded on Public Service's books as they deploy. When these deployments begin, a shared asset credit will be calculated as discussed by Ms. Wold and included as a credit to the AGR revenue requirement as discussed by Ms. Blair. If limited to recovery in a base rate case, this credit amount would only be embedded in the test year used to set rates and reflect only representative test year amounts. The AGR will allow for this benefit to be provided to customers as the Company actually realizes it. The good news is that our Colorado customers directly benefit. Timely inclusion of these credits in what is assessed to Colorado customers is another valid reason for approval of a rider mechanism in this instance.

Q. ARE THERE OTHER POLICY REASONS TO APPROVE THE PROPOSED AGR?

A. Yes. Rider recovery will also smooth out the rate impacts associated with implementation of the AGIS initiative. Public Service has been working on the implementation of the AGIS initiative since before filing the CPCN application in 2016 and certain portions of the AGIS investments are currently in-service and used and useful for our customers, such as components of ADMS. Public Service's 2019 Electric Rate Case included a portion of the costs of certain AGIS projects that were in serviced in 2019. However, the Company is continuing to implement and has placed in service additional components of AGIS in 2019 and the first half of 2020 that were not captured through the recent rate case and continues to defer costs in accordance with the AGIS CPCN Settlement. If cost recovery for these components is delayed until the next rate case, the bill impact for Public Service's customers will be more significant than if recovery is spread out in smaller increments across each year of the AGIS implementation.

Q. PLEASE SUMMARIZE THE REASONS THAT SUPPORT RIDER RECOVERY FOR PUBLIC SERVICE'S AGIS COSTS.

A. The AGIS initiative is a long-term strategic initiative to transform Public Service's distribution system through improved distribution technology to increase grid reliability, security, transparency, efficiency, and customer choice. The execution of this important initiative requires significant initial financial outlay by Public Service. The timely recovery of these necessary investments through a rider serves the public interest by:

- Replacing aging and obsolete facilities;
- Reducing regulatory lag;
- Diminishing the need for more frequent rate cases;
- Reflecting prior support for the projects, including in the AGIS CPCN Settlement and rate case recovery to date;
- Providing even more reporting and oversight than typical rate case recovery;
- Providing a cost-true-up mechanism to ensure costs charged to customers reflect actual investments;
- Providing shared asset credits to customers as the Company realizes them; and
- Avoiding erratic bill impact spikes by smoothing cost recovery across each year of the AGIS implementation.

Q. THE COMPANY HAS RECENTLY FILED FOR APPROVAL OF ANOTHER RIDER TO RECOVER COSTS ASSOCIATED WITH WILDFIRE MITIGATION. WHY IS IT APPROPRIATE FOR THE COMMISSION TO APPROVE BOTH OF THESE RIDERS?

A. These two riders address different but vital needs of customers and Public Service that happen to arise at the same time. As discussed previously, the AGR addresses the need to modernize the distribution system to bring about an intelligent, automated, and interactive electric distribution system that will allow operators more visibility into the system for a more secure and resilient grid and allow customers access to timely energy information. Separately, the WPR addresses the need to perform critical work necessary to mitigate the risk of wildfires within Public Service's service territory. As Public Service recently completed a Phase I electric rate case, approval of these two riders is necessary at this time to provide a mechanism for recovery of the costs for these two important projects.

IV. ADVANCED GRID RIDER (AGR)

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

A. In this section of my Direct Testimony, I present the Company's proposed AGR tariff, explain the mechanics and applicability of the tariff, and discuss how the Company plans to procedurally implement the rider. The mechanics of the AGR are likewise summarized at a high level in Attachment SPB-2 to my Direct Testimony.

Q. PLEASE PROVIDE AN OVERVIEW OF THE AGR TARIFF.

A. The proposed AGR tariff is provided as Attachment SPB-1 to my Direct Testimony and provides the applicable projects; descriptions of the annual estimate, true-up filings, and reporting; and the revenue requirement calculation.

Q. WHAT PROJECTS ARE ELIGIBLE FOR RECOVERY UNDER THE AGR?

A. As I discussed earlier in testimony, the incremental revenue requirement for the following projects will be eligible for recovery:

- IVVO;
- AMI and HAN;
- FAN;
- ADMS (including GIS);
- FLISR and FLP; and
- APT.

Q. PLEASE EXPLAIN THE TIMING AND PROCESS OF THE ANNUAL AGR FILINGS.

A. Each proposed revision to the AGR will be filed annually by advice letter on or before November 15 of each year, to reflect the forecasted revenue requirement for the following year to be effective January 1. On or before April 15 of each year, the Company will make an annual true-up filing to identify the difference between the collected revenues and actual costs. Each annual true-up will be incorporated into the annual revenue requirement revision to be filed the following November 15.

Q. CAN YOU PROVIDE ADDITIONAL INFORMATION REGARDING THE INFORMATION THAT WILL BE PROVIDED WITH THE ANNUAL FILINGS?

A. Yes. As I mentioned above, the Company currently provides an annual forecast report in October of each year with the forecast for the upcoming calendar year, and a report in April of each year containing the actuals from the previous year in accordance with the terms of the AGIS CPCN Settlement. The Company will continue to provide the same robust detail with the AGR that it currently provides in these annual reports, but for all projects included in the AGR.

Q. WHAT INFORMATION WILL BE PROVIDED IN THE NOVEMBER FORECAST REPORT?

A. The annual forecast report will provide: (1) a forecasted revenue requirement for the upcoming year including all the detail I discuss below and that discussed by Ms. Blair in her Direct Testimony; (2) any updates to the full-term business plan, including the scope of work for projects; (3) details of the forecasted O&M and capital expenditures for the upcoming year by project; and (4) any updates to planning and implementation of customer education.

Q. WHAT INFORMATION WILL BE PROVIDED IN THE APRIL ACTUALS REPORT?

A. The annual actuals report will provide: (1) a true-up of the prior year's revenue requirement including all the detail I discuss below and that discussed by Ms. Blair in her Direct Testimony; (2) a true-up of the actual revenue collected under the AGR to the actual revenue requirement; (3) an overview of the previous year's progression on the business plan; (4) details of the actual versus forecasted O&M and capital expenditures for the reporting year by project; (5) milestones and overall project status for each project; (6) any updates to planning and implementation of customer education; (7) when applicable, the final cost per AMI meter, both including and excluding installation and taxes; (8) the total number of AMI meters installed in the reporting year; and (9) comparison of total spend to the overall budget.

Q. WILL THE AGR FORECAST AND ACTUALS REPORTS REPLACE THE EXISTING REPORTING REQUIREMENTS UNDER THE AGIS CPCN SETTLEMENT?

A. Yes. All of the reporting requirements under the AGIS CPCN Settlement will be met in the proposed annual reporting under the AGR.

Q. DOES THE STRUCTURE OF THE PROPOSED AGR REFLECT EXISTING COMMISSION-APPROVED ADJUSTMENT MECHANISMS?

A. Yes. The Company has structured its proposed AGR using a framework similar to other adjustment clauses in place, such as the Company's PSIA and Transmission Cost Adjustment ("TCA"), but with even greater reporting requirements.

Q. HOW WILL THE COMPANY CALCULATE THE ANNUAL REVENUE REQUIREMENT FOR THE AGR?

A. Once the annual AGR revenue requirement is calculated, the amount of AGIS costs already included in base rates is subtracted so that the revenues recovered through the AGR represent only costs that are incremental to, or in addition to, those already reflected in base rates. This total will be summed with the remaining costs with the previous year's true-up amount (either positive or negative), as I describe below.

Further, should any changes to base rates occur as part of a future rate case, the Company will simultaneously adjust the AGR to remove any applicable costs rolled into base rates. More detail regarding the calculation and individual components of the Company's AGR revenue requirement are set forth in Ms. Blair's Direct Testimony.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED TRUE-UP MECHANISM FOR UNDER- OR OVER-RECOVERY ASSOCIATED WITH THE AGR.

A. The Company plans to true-up both the revenue requirement and actual revenue collected on an annual basis through a filing made annually on or before April 15. Any true-up adjustments will be rolled into the following year's AGR as part of the annual revenue requirement estimate filed on or before November 15. If the Company determines that it over-collected through the AGR in the previous calendar year, based on the forecasted revenue requirement for that year, the following year's estimated AGR will be reduced by the difference between forecasted and actual costs. The opposite will apply if the Company finds that the

AGR under-collected for a given calendar year. This true-up mechanism will ensure the accuracy of the Company's year-to-year cost recovery through the AGR. Ms. Blair explains the true-up mechanism in more detail in her Direct Testimony.

Q. FROM A PROCEDURAL PERSPECTIVE, HOW DOES THE COMPANY PROPOSE TO IMPLEMENT THE AGR IF THE COMMISSION ISSUES A DECISION APPROVING THE AGR IN THIS PROCEEDING?

A. In its final Commission decision approving the AGR, Public Service is requesting that the Commission authorize the Company to file a compliance advice letter on not less than two days' notice, updating the AGR tariff as needed to reflect all terms and conditions that are approved in this proceeding. While it would be the Company's preference to initiate the AGR as early in 2021 as possible, Public Service recognizes that may not occur before the beginning of 2021. The Company's 2021 forecasted revenue requirement in this proceeding is calculated on an annual basis and will only be billed for the portion of the year beginning after the AGR is approved. The Company will then true-up its 2021 revenue requirement for the months of eligible AGR recovery via the April 2022 actuals filing, with any true-up amount recovered through the 2023 forecasted amount.

Q. PLEASE SUMMARIZE WHY THIS OVERALL APPROACH TO THE AGR IS REASONABLE.

A. The Company is proposing a rider mechanism that provides clear and consistent information to the Commission; allows for current cost recovery and timely passes benefits to customers on a reasonable basis, consistent with other riders currently in effect; and ensures customers will ultimately pay no more or no less than actual costs on a year-over-year basis. This rider proposal is intended to be balanced and fair to all involved, while supporting these important investments in the distribution system.

V. COST ALLOCATION AND BILL IMPACTS

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

A. In this section of my Direct Testimony, I present the Company's proposed cost allocation for AGR costs and the bill impacts to customers based on the proposed allocation. I explain how the Company proposes to allocate AGR costs across customer classes and why the Company believes the proposed allocation properly assigns costs to the appropriate classes.

Q. HOW WILL THE AGR COSTS BE ALLOCATED AMONG RATE CLASSES?

A. The several projects included in the AGR will each serve different groups of customers; as such, there will be specific cost allocations for each project. The cost allocation methods used for the AGR are consistent with those in the Company's last Phase II electric rate case in Proceeding No. 16AL-0048E ("2016 Phase II Electric Rate Case") and have been updated for 2021 sales volumes, which are reflected in Attachment SPB-3.

Q. HOW WILL THE AMI COSTS BE ALLOCATED TO CUSTOMER CLASSES?

A. Typically, meter costs are allocated to classes based on the number of customers in each class weighted by the average cost of meters in each class. This ensures that larger customers with relatively expensive meters are allocated a proportionately larger share.

However, the AGIS CPCN Settlement included a provision that required the Company to present a proposal for assigning a portion of AMI meter costs as something other than customer-related.[11] In the 2019 Electric Rate Case, Company witness Ms. Michelle M. Applegate presented an analysis that split the costs of AMI meters between customer and distribution functions.[12] The result of the analysis functionalized 82.9 percent of AMI costs as metering costs and 17.1 percent as secondary distribution costs due to their support of the distribution system. The customer-related AMI costs will be allocated across customer classes based on the number of customers in each class weighted by the cost of meters for each class. The secondary distribution portion of AMI costs will be allocated based on class non-coincident peak ("NCP") and the sum of individual maximum demand. This is consistent with how secondary distribution costs were allocated in the Company's 2016 Phase II Electric Rate Case.

Q. HOW WILL THE COST OF THE ADMS BE ALLOCATED TO CUSTOMER CLASSES?

A. As discussed by Mr. Nickell, the ADMS system will provide multiple benefits across the grid, which will benefit all customers. As such, the Company proposes that the costs of ADMS be allocated to all customer classes based on the NCP of each class, including the transmission class. In contrast to most of the other costs in the AGR that are specific to the distribution system and customers that receive primary or secondary distribution service, ADMS will provide overall system benefits through dynamic modeling and real-time power flow information.

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[11] See AGIS CPCN Settlement, Section (III)(E)(4), page 18.
[12] See Direct Testimony of Michelle M. Applegate page 69-72 as well as Attachment MMA-5.

Q. HOW WILL THE COSTS OF THE FAN BE ALLOCATED TO CUSTOMER CLASSES?

A. The Company proposes to allocate the costs of the WiSUN portion of the FAN in the same way it allocated the cost of AMI. The purpose of WiSUN is to support the AMI meters; as such, the cost allocation for WiSUN should follow that of AMI. The cost of the two-way wireless network (replacement for WiMAX) will be part of the distribution system, with base stations installed at substations and customer premise equipment mounted on distribution poles. As such, these costs will be allocated the same as distribution assets using NCP, excluding the transmission class.

Q. HOW WILL THE COSTS OF FLISR, IVVO, AND APT BE ALLOCATED?

A. All three will be allocated using NCP, excluding transmission. FLISR, IVVO, and APT are all distribution programs and should be allocated to customers utilizing the distribution system. As noted previously, NCP was the allocation method used for primary voltage distribution assets in the Company's 2016 Phase II Electric Rate Case.

Q. WHAT IS THE OVERALL CLASS COST ALLOCATION FOR THE AGR?

A. The expected class cost allocation of the AGR revenue requirement is provided in Table SPB-D-6 below and detailed in Attachment DAB-1 to the Direct Testimony of Ms. Blair. The Company updated its class cost allocation factors for 2021-expected customer counts and sales volumes. For 2022 and beyond, the volumes and cost allocations will be updated annually in the November 15 AGR forecast filings. For the purposes of Table SPB-D-6, however, the allocation factors have been held constant for 2021 through 2025.

Overall the residential class will receive the largest allocation of AGR costs. This is because AMI meters represent the largest program cost in the rider, AMI cost are allocated based on the number of customers in each class, and the residential class has by far the greatest number of customers.

Table SPB-D-6
AGR Class Cost Allocation 2021-2025

Customer Class	2021	2022	2023	2024	2025
Residential	$28,816,618	$37,447,907	$45,787,603	$48,992,239	$55,414,879
Small Commercial	$ 4,592,440	$ 5,946,398	$ 7,336,000	$ 7,795,995	$ 8,960,703
Secondary General	$14,972,522	$19,781,103	$23,206,134	$25,632,206	$26,851,484
Primary General	$ 3,069,306	$ 4,049,812	$ 4,766,602	$ 5,251,641	$ 5,535,808
Transmission General	$ 1,104,133	$ 1,196,798	$ 1,418,793	$ 1,413,342	$ 1,503,950
Lighting	$ 156,070	$ 209,250	$ 236,381	$ 268,852	$ 261,572
Total	$52,711,089	$68,631,267	$82,751,513	$89,354,275	$98,528,396

Q. HOW WILL AGR RATES BE STRUCTURED?

A. The Company proposes to structure the AGR rates similar to other rate adjustments currently used. For Residential and Small Commercial customers, the rates will be an energy or kWh-based charge. For C&I customers, the AGR will utilize demand- or kW- based charges. In 2021, a typical residential electric customer's bill would increase by $1.90 a month, or 2.76 percent, from $69.04 to $70.94, based on average monthly usage. A typical small-business electric customer would see an increase of $3.35 a month, or 3.25 percent, from $102.99 to $106.34, based on average monthly usage. Further detail of the 2021 bill impacts are included in Attachment SPB-3.

Q. WHAT ARE THE FORECASTED AVERAGE BILL IMPACTS OF THE AGR?

A. Table SPB-D-7 provides the forecasted incremental and total bill impacts for 2021 through 2025, based on the detailed revenue requirement in Ms. Blair's Attachment DAB-1. In general, customers in the Small Commercial class are expected to have the largest bill impact due primarily to the cost allocation of AMI infrastructure. Conversely, Transmission customers are expected to have the smallest bill impact because they are not allocated many AGR costs associated with distribution projects.

Table SPB-D-7
AGR Estimated Incremental Bill Impacts 2021-2025

Customer Class	2021	2022	2023	2024	2025	Total
Residential	2.76%	0.83%	0.79%	0.32%	0.61%	5.31%
Small Commercial	3.25%	0.95%	0.98%	0.33%	0.83%	6.34%
Secondary General	1.38%	0.46%	0.33%	0.21%	0.12%	2.50%
Primary General	1.23%	0.39%	0.28%	0.19%	0.12%	2.21%
Transmission General	0.83%	0.07%	0.17%	0.00%	0.07%	1.14%

Q. WHY ARE THESE BILL IMPACTS REASONABLE?

A. As described throughout this filing, the AGIS costs are providing an important service to customers and key advancements for the Company's distribution grid. Further, the Company has carefully allocated AGR costs according to established methods and the purpose of the individual projects, resulting in rates that are just, reasonable, and in the public interest.

VI. AGR CASE EXPENSES

Q. IS PUBLIC SERVICE INCURRING EXPENSES TO PREPARE AND PROSECUTE THIS CASE?

A. Yes. Public Service has already incurred expenses to prepare the case filing and will continue to incur expenses to perform the other tasks attendant to filing and litigating this case before the Commission.

Q. IS PUBLIC SERVICE PROPOSING TO RECOVER THESE EXPENSES IN THE AGR?

A. No. The Company requests the Commission defer the review, approval, and recovery of these expenses to the next Phase I electric rate case. Specifically, AGR case expenses would be deferred into a regulatory asset without interest until they are presented for cost recovery in the next Phase I electric rate case. The Company commits to presenting actual AGR expenses at the time of that filing.

Q. WHY IS IT APPROPRIATE FOR PUBLIC SERVICE TO INCLUDE AGR CASE EXPENSES AS A RECOVERABLE ITEM IN THE COST OF SERVICE?

A. Most businesses have the flexibility to set their prices based on their assessment of the market and the demand for their products. Utilities that are subject to cost of service regulation do not have this same flexibility, but rather must make rate, or in this instance rider, filings and obtain public utility commission authorization to establish new rates. Accordingly, it is my understanding that it has been the long-standing practice of this Commission to treat reasonable expenses of cost recovery and other rate case proceedings as a necessary cost of doing business and, after review, to allow recovery of such expenses through mechanisms established in a rate case proceeding. Further, as I discussed earlier in testimony, the AGR will likely increase the time between Phase I electric rate cases, thus reducing expenses to file those cases over the period the AGR is in effect.

Q. WHAT AMOUNT OF AGR EXPENSE DOES PUBLIC SERVICE EXPECT TO INCUR IN THIS PROCEEDING?

A. The total expenses associated with this filing are estimated to be $546,602, assuming a fully-litigated case.

Q. PLEASE LIST AND GENERALLY DESCRIBE THE MAJOR EXPENSE CATEGORIES YOU EXPECT THE COMPANY TO INCUR RELATED TO THIS FILING.

A. The major categories of expenses include the following:

<u>Transcripts/Hearing Costs:</u> During the course of the case, a court reporter may be necessary to transcribe depositions and hearings before the Commission or administrative law judge. There is a cost for the court reporters to record and then transcribe these proceedings. This fee increases or decreases based upon the length of the transcript and the timeframe in which the reporter must turn over the transcript. Hearing costs are the costs for Company witnesses to travel to attend the hearing and other necessary meetings to prepare for hearing.

<u>Legal Counsel:</u> The Company does not staff its legal department assuming continuous ongoing rate or rider filings. Additionally, the expertise to file a comprehensive rate or rider case is not always in-house for all topics; thus, outside

legal assistance is necessary. Therefore, outside legal assistance in developing, processing, and litigating a case is a valid rider expense.

Customer Noticing: Pursuant to Rule 1207, the Company must provide a notice to its customers regarding the proposed rate change and the impacts on customers. Customer noticing includes costs to post legal notices in major area newspapers for two consecutive weeks, including one Sunday, as required by Commission rules, as well as direct-mailed onserts printed on customer bills to notify customers of the filing.

Q. HOW DO THESE COST CATEGORIES TRANSLATE INTO THE TOTAL ESTIMATED RIDER EXPENSES?

A. Table SPB-D-8 below lists the categories of expenses described above and the total cost estimate for each category.

Table SPB-D-8
Rider Expenses by Category

Category	Expense Estimate
Transcripts/Hearing Costs	$14,475
Legal Counsel	$500,000
Customer Noticing	$32,127
Total	**$546,602**

Q. ARE THE COSTS DESCRIBED ABOVE REASONABLE?

A. Yes. The largest portion of estimated expenses are associated with outside legal counsel. As I discussed above, the Company retains outside legal counsel because the Company does not staff for continuous ongoing rate or rider cases. In this case, we retained a firm with rate recovery expertise and specific knowledge of Public Service and other Xcel Energy operating companies, including the

Company's AGIS initiative. The firm has provided, or will provide, assistance in assembling testimony and attachments, witness preparation, advice on strategy, responding to discovery, and generally processing the case. I would also add that the Company's internal legal team works hard to ensure that duties are appropriately assigned to outside legal counsel and to ensure that work efforts are not duplicative. The internal and external legal teams work as a unit and are in constant coordination to be as efficient as possible.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend that the Commission authorize Public Service to implement its proposed AGR consistent with the terms and conditions reflected in Attachment SPB-1, including authorizing the 2021 AGR revenue requirement forecast presented by Ms. Blair and authorizing the Company to integrate its reporting requirements from the AGIS CPCN Settlement into the AGR reporting requirements. I also recommend that the Commission authorize application of a five percent depreciation rate to the AMI meters, approve the Company's proposal to create a regulatory asset to recover the undepreciated balance of legacy meters that will be replaced by AMI meters, and approve the Company's proposal to defer the costs of this proceeding for potential future recovery.

Q. DOES THIS CONCLUDE YOU DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Steven P. Berman

I accepted the position of Director, Regulatory Administration in January 2020. In that role, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service Company of Colorado. In my prior role with Xcel Energy, Manager of Revenue Analysis, I was responsible for leading a team of analysts who develop revenue requirements models to support the rates charged by Public Service. My responsibilities included directing, reviewing, and analyzing the revenue requirements that support the base rates, rate riders, and FERC formula rates used by Public Service.

I have worked in the energy industry for over 13 years. Over that time, I have worked for Xcel Energy and Colorado Springs Utilities in progressively more responsible roles. Prior to working in the utility industry, I held various positions in marketing and finance after graduating college in 1999. In June 2006 I began working at Colorado Springs Utilities as a Senior Analyst in the corporate budgeting group. In June 2008 I accepted a position as a Financial Consultant with Xcel Energy supporting the Customer Care organization, where I provided financial analysis and support for customer care and bad debt expenses used in rate cases across Xcel's jurisdictions.

In July 2010, I returned to Colorado Springs Utilities as a Principal Financial Analyst and in July 2011 accepted the position of Financial Planning & Analysis Manager. In that role, I was responsible for the budget and revenue requirements of the organization. I presented them annually to the City Council who acts as the regulator for Colorado Springs Utilities. In March 2014, I accepted the position of Treasury Manager. In that role, I directed all cash and financing activities of the utility. I worked closely with the Chief Financial Officer to develop an annual financing plan and present it to the board and credit rating agencies in support of the utility's strong "AA" credit rating. Prior to my current position, I accepted the position of Revenue Analysis Manager with Xcel Energy in April 2015.

I graduated from the University of Maryland in 1999 with a Bachelor of Science degree in Business Administration, and from George Washington University in 2005 with a Master's in Business Administration concentrating in Finance. I am a licensed Certified Public Accountant in Colorado.

I have submitted written testimony before the Commission in a number of proceedings.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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

AFFIDAVIT OF STEVEN P. BERMAN
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

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

Dated at Denver, Colorado, this 17 day of July, 2020.

Steven P. Berman
Director, Regulatory Administration

Subscribed and sworn to before me this 17th day of July, 2020.

SCHUNA D WRIGHT
Notary Public
State of Colorado
Notary ID # 19974007693
My Commission Expires 05-06-2021

Schuna D. Wright
Notary Public

My Commission expires May 6, 2021