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

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IN THE MATTER OF ADVICE LETTER NO. 1906-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO REVISE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL ELECTRIC RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE DECEMBER 31, 2022.	**PROCEEDING NO. 22AL-XXXXE**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF STEVEN P. BERMAN</u>

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

November 30, 2022

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

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IN THE MATTER OF ADVICE LETTER NO. 1906-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO REVISE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL ELECTRIC RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE DECEMBER 31, 2022.	)	**PROCEEDING NO. 22AL-XXXXE**

EXECUTIVE SUMMARY

Public Service Company of Colorado ("Public Service" or the "Company") submits this electric base rate case in support of our continuing mission to lead the clean energy transition while providing safe and reliable electric service and a high-quality customer experience in a cost-effective manner. Our requests in this proceeding are designed to maintain the financial integrity of the Company as we continue to make the investments in our distribution, transmission, generation, and business systems that are necessary to advance state policy goals and meet our service obligations to our customers. Our requests are also narrowly tailored to timely address the rising costs of meeting our obligations to customers, taking into account the effects of inflation, supply chain constraints, competition for market capital, and increasing cost pressures across the electric service business. In short, we ask the Colorado Public Utilities Commission

("Commission") and other stakeholders to meet these challenges and support our role in serving our customers and Colorado communities.

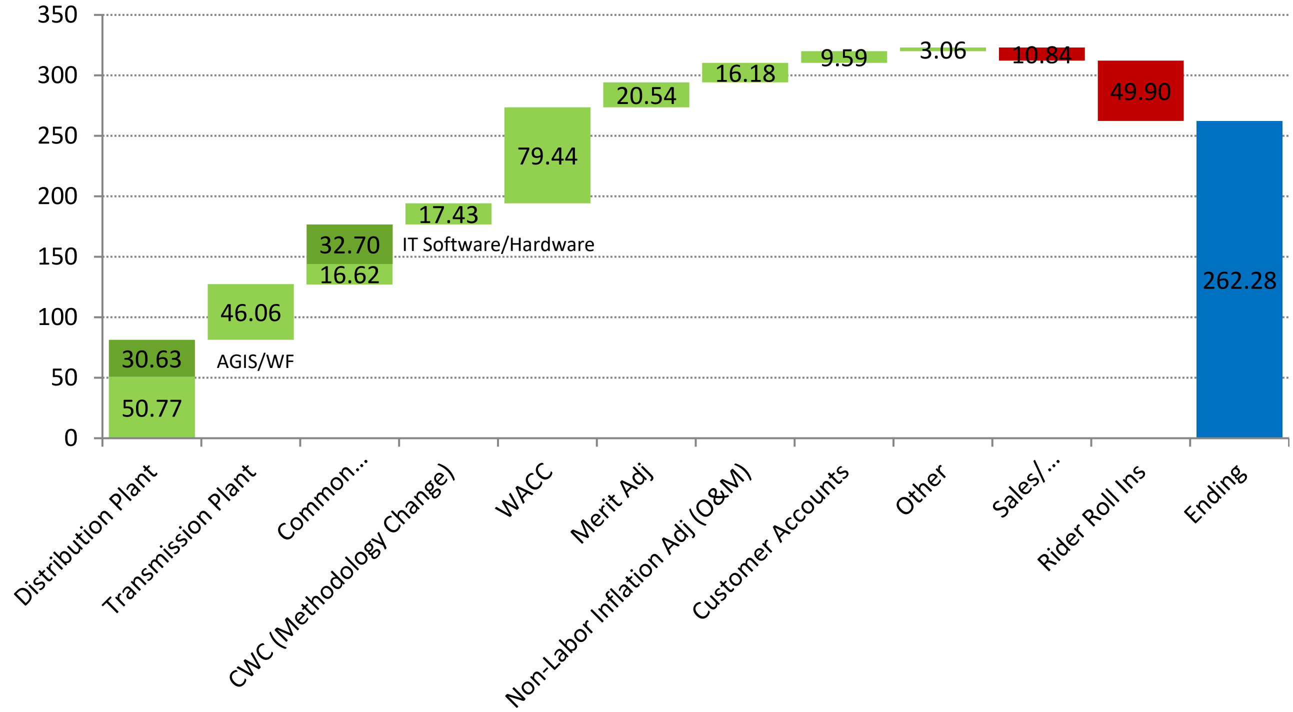
Public Service has already established itself as a leading partner in the clean transition in the State of Colorado and across the Xcel Energy footprint. In 2021 wind energy made up 33 percent of Public Service's energy supply, and by the end of 2021 Public Service had nearly 4,100 MW of installed wind energy capacity on its system. Public Service has also nearly completed its Colorado Energy Plan Portfolio approved by the Commission as part of the Company's 2016 Electric Resource Plan, retiring more than 660 MW of coal-fired generation by late 2025 and adding 1,100 MW of wind, approximately 750 MW of solar, and 275 MW of storage to the Colorado generation fleet. Meanwhile, we are driving demand side management; beneficial electrification; grid modernization to accelerate customer choice, energy efficiency, and distributed energy resources; electric vehicle adoption; and conservation opportunities for disadvantaged customers and communities throughout our service territory. Overall, Public Service anticipates achieving approximately an 85 percent carbon emissions reduction relative to a 2005 baseline by 2030, and Xcel Energy plans to transition to 100 percent carbon-free electricity by 2050. At the same time, we are a proud community partner, one of the largest taxpayers in the State of Colorado, and one of the largest employers and philanthropic organizations.

As we are undertaking these ambitious and successful programs as both an Electric Utility and community partner, we also have a continuing obligation to maintain the essential safe and reliable service on which our customers depend. This requires continuing investment in our electric and business systems, in order to address aging infrastructure, ensure system resiliency, and meet our customers' needs. To these ends, the key drivers of the base rate change we are requesting in this case include fundamental capital investments for an Electric Utility, including those in our distribution, transmission, and information technology (IT) systems. Labor and other operations and maintenance costs are also on the rise for Public Service, just as inflation is affecting the broader marketplace and the communities in which we operate and serve. We are also requesting a change in our overall weighted average cost of capital, as both our costs of debt and the return on equity our shareholders require have increased with rising interest rates and changes in broader market dynamics.

Importantly, however, our base rate revenue request is offset somewhat by sales growth that reduces this necessary rate change for our customers. Further, our proposed change in base rate revenue also reflects the transition of costs previously recovered through riders to base rates, as well as recovery of costs the Commission previously approved for deferral, which do not constitute new revenue but rather a shift in the means of cost recovery. Thus, if this rate proposal is approved, customer bills will remain low – and below the national average.

Figure SPB-ES-1 below summarizes the drivers of our revenue requirement request in this proceeding, including our previously-approved initiatives.

Figure SPB-ES-1:
Base Rate Deficiency Drivers
2021 Phase I Rate Case to Proposed Revenue Change



Finally, in this case Public Service proposes a modest step forward from the test year established in our 2021 Electric Phase I rate case, to further align Colorado ratemaking with the forward-looking plans of this Commission. In any rate case, the test year is the starting point for establishing new rates. In our 2021 Electric Phase I, all parties to the case entered into a unanimous settlement to establish a calendar year 2021 test year with a capital true-up, enabling rates to take effect within a few months of the conclusion of the test year. Here, we are proposing a similar test year, ending December 31, 2023 with rates expected to take effect in September of 2023. We consider this a modest step forward for several reasons: While we include some forecasted capital and revenues in our test year, our O&M is largely based on actual data through June 30, 2022, as adjusted for individual changes and inflationary impacts on the business. We are also proposing a full-scale customer protection mechanism in the form of an earnings sharing opportunity with our customers. We are providing additional information requested by the parties since our last electric rate case, are not proposing a multi-year framework, and also continue to look for additional ways to make the overall ratemaking process more efficient and productive for all stakeholders. Accordingly, our overall proposals in this case, if accepted, would constitute a moderate, incremental advance toward more forward-looking ratemaking – an approach that both supports the Company's opportunity to recover its reasonable costs of service during the period rates will be in effect, and also aligns with the efforts of this Company and this Commission to plan for a cleaner, more resilient, and increasingly bright energy future.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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IN THE MATTER OF ADVICE LETTER NO. 1906-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO REVISE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL ELECTRIC RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE DECEMBER 31, 2022.	**PROCEEDING NO. 22AL-XXXXE**

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<u>DIRECT TESTIMONY AND ATTACHMENTS OF STEVEN P. BERMAN</u>

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 Company of Colorado ("Public Service" or the "Company") as Regional Vice President of Regulatory and Pricing.

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 Regional Vice President of Regulatory and Pricing, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service. My duties include the design and implementation of Public Service's regulatory strategy and programs, as well as the direction and supervision of Public Service's regulatory activities, including oversight of rate filings, administration of regulatory tariffs, rules and forms, regulatory case direction and administration, compliance reporting, and complaint responses. A description of my qualifications, duties, and responsibilities is set forth in my Statement of Qualifications at the conclusion of my testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to provide an overview of Public Service and our leadership of the clean energy transition as they pertain to this proceeding, introduce the need for Public Service's Phase I rate requests, and provide policy support for the Company's thoughtful, incremental, customer-focused approach to ratemaking in this proceeding. I provide a brief overview of Public Service and its electric business and discuss the need for this rate case and the potential impacts on our customers. I then introduce the additional witnesses providing support for this proceeding, and the Company's specific recommendations throughout this filing. Overall, I support the Company's request that the Commission approve an overall base rate revenue requirement for Public Service's retail electric operations of $2,452.7 million, which is calculated based upon a test year (the "Test Year") ending December 31, 2023. When compared to the forecasted 2023 revenue under present rates of $2,140.5 million, the Company's total requested change in base rate revenue is $312.2 million. However, approximately $49.9 million of this total base rate revenue increase consists of transferring amounts previously recovered through riders, resulting in a net base revenue change of $262.3 million.

My Direct Testimony also provides a ratemaking policy discussion, in which I discuss the components of the Company's proposed Test Year, rate requests, and customer protections, and why they lead to establishment of just and reasonable rates. I also introduce the Company's efforts toward an increasingly efficient and productive ratemaking process. Ultimately, my testimony supports the Company's overall request for a base rate increase and its additional requests and recommendations in this proceeding.

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: Summary of Proposed Base Rate Revenue Change
- Attachment SPB-2: Summary of Company Recommendations
- Attachment SPB-3: Summary of Forward Looking Test Year Filing Requirements in Other States

Q. WHAT RECOMMENDATIONS ARE YOU MAKING IN YOUR DIRECT TESTIMONY?

A. Overall, I recommend that the Colorado Public Utilities Commission ("Commission") approve the Company's requested revenue requirement and base rate increase in this Phase I rate proceeding, as well as associated tracker mechanisms, deferred balance amortizations, and tariff changes, with a General

Rate Schedule Adjustment ("GRSA") taking effect on or before September 7, 2023. As part of this overall recommendation, I recommend that the Commission approve the Company's requested capital additions, operations and maintenance ("O&M") expense, and components of the weighted average cost of capital ("WACC"), as well as the Company's proposed depreciation rates, as part of its overall Test Year proposal. I also recommend that the Commission approve the Company's earnings sharing mechanism proposal. Consistent with Decision No. C22-0724 in Proceeding No. 21AL-00317E, the Company will be filing its Phase II Electric rate case no later than May 15, 2023, and will propose appropriate Phase II rate and tariff changes at that time.

Q. CAN YOU PROVIDE A MORE DETAILED LIST OF THE COMPANY'S REQUESTS AND RECOMMENDATIONS IN THIS PROCEEDING?

A. Yes. It has long been the Company's practice to provide a detailed list of its rate case requests in the policy testimony. As part of our stakeholder outreach between the Company's 2021 Electric Phase I and this rate case, we heard from stakeholders that they would appreciate a detailed list of requests accompanied by the location(s) in the Company's overall testimony where support for each request can be found. Attachment SPB-2 to my Direct Testimony itemizes the Company's requests as well as the location in testimony where support for such requests can be found. Please note that while this list is intended to capture the majority or all of the support for each request, for future discovery, testimony, and briefing the Company reserves the right to refer to other areas of its case that may also be determined to be relevant (depending on the nature of the issue). As a whole, the Company requests that the Commission approve its base rate request, programmatic proposals, and tariff changes in this proceeding.

II. OVERVIEW OF PUBLIC SERVICE AND THIS RATE CASE

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

A. In this section of my Direct Testimony, I first discuss the Company's leadership in providing safe, clean, reliable, and affordable electric service to our customers, as well as the important role Public Service plays in our communities and among our stakeholders. I then turn to the need for this rate case, discussing in turn the drivers of the Company's revenue deficiency and the overall impacts of our requests. I also introduce the other witnesses who will be providing support for our requests in this proceeding, including the requests and recommendations identified in Attachment SPB-2 to my Direct Testimony and referenced above.

A. Public Service's Leadership of the Clean-Energy Transition and Services to Our Customers

Q. WHAT TOPIC DO YOU ADDRESS IN THIS SECTION OF YOUR DIRECT TESTIMONY?

A. I describe Public Service's leadership role in Colorado's clean-energy transition and the Company's efforts to promote economic development in Colorado. I also highlight opportunities ahead to further expand clean energy offerings, through legislation like the Inflation Reduction Act and programs like Public Service's Transportation Electrification Plan. Finally, I explain that Public Service provides safe and reliable electric service to its customers at a reasonable cost.

Q. PLEASE SUMMARIZE PUBLIC SERVICE'S ROLE IN LEADING THE CLEAN-ENERGY TRANSITION AND PROMOTING ECONOMIC DEVELOPMENT.

A. Public Service is more than just a provider of the safe and reliable electricity that powers the Colorado economy – it is itself a driver of economic growth in each component of our traditional vertically-integrated utility business. The Company is leading the clean-energy transition in Colorado as we progress through a series of aggressive carbon emission reduction targets and implement measures to help protect the residents of Colorado from the effects of climate change.

Specifically, Public Service is on track to continually meet and exceed Colorado's Renewable Energy Standard ("RES"). The Company has continued to meet the State's RES requirements, and has established ambitious plans to transition to 100 percent carbon-free electricity by 2050. In 2021, wind energy alone made up 33 percent of Public Service's energy supply, and by the end of 2021 Public Service had nearly 4,100 MW of installed wind energy capacity on its system. Meanwhile, Xcel Energy has established its plan to reduce carbon emissions by 80 percent by 2030, all while keeping customer bills low.

Q. WHAT ARE SOME OF THE FORWARD-LOOKING STEPS THE COMPANY HAS TAKEN AND IS TAKING TO LEAD THE CLEAN ENERGY TRANSITION?

A. We are in the process of implementing and carrying out a number of programs and initiatives that are proactively designed to support Colorado's short- and long-term environmental policy goals.

The most impactful of these programs and initiatives is the Company's Electric Resource Plans ("ERP") and Clean Energy Plan ("CEP"). The Company has nearly completed the implementation of its Colorado Energy Plan Portfolio ("CEPP") that was approved by the Commission as part of the Company's 2016 ERP (Proceeding No. 16A-0396E) and involves retiring 660 MW of coal-fired generation by late 2025 and adding 1,100 MW of wind, approximately 750 MW of solar and 275 MW of storage to our Colorado generation fleet. More recently, the Company followed this CEPP with its 2021 ERP & CEP which forecasts approximately 85 percent carbon emissions reductions relative to a 2005 baseline by 2030. This ERP & CEP includes the planned retirement or conversion of all of the Company's remaining coal assets; the forecasted acquisition of approximately 4,000 MW of new renewable energy resources and 200 MW of additional battery storage; and plans to support our communities through a just and planned transition away from coal generation and to a clean energy future. The Commission approved Phase 1 in August 2022 and the Company anticipates releasing the Phase 2 request for proposals by the end of this year.

Public Service is also investing heavily in the transmission infrastructure necessary to support its ERPs and CEP and this investment helps to promote economic growth in many of our communities. The most prominent example of this is the Company's Colorado's Power Pathway project ("Pathway Project"). The Pathway Project is under construction with at least two segments forecasted to be in-service by September, 2025. Other segments will follow in 2026 and 2027 at which point the Pathway Project will be complete and help interconnect up to 5,000 MW of new, clean energy resources.

Q. HOW IS THE COMPANY DRIVING DEMAND SIDE MANAGEMENT ("DSM") AND BENEFICIAL ELECTRIFICATION ("BE") OPPORTUNITIES TO ADVANCE THE STATE'S GREENHOUSE GAS EMISSION REDUCTION GOALS?

A. On July 1, 2022, the Company filed two important DSM and BE filings. The first is the Company's 2022 DSM & BE Strategic Issues ("DSM Strategic Issues") filing which sets the guidelines and frameworks for 2024 – 2027. This proceeding sets the Company's goals and budgets; creates the policies by which the Company will implement future programs; and determines certain assumptions by which programs are measured and the Company is incentivized. Specifically, in this DSM Strategic Issues filing, the Company has asked for approval to emphasize the reduction of carbon emissions through DSM and BE in lieu of the traditional strategy of maximizing energy savings. This shift in strategy is possible because of the significant reductions in our electric generation carbon emissions, discussed above, that have made BE a viable strategy for reducing customers overall emissions and because the impact of cost-effective, clean energy resources has changed the value proposition of energy savings with certain times of day offering more value than others.

The second filing is the Company's 2023 DSM and BE Plan. This Plan is, in part, a bridge between the Company's existing programs and the future of DSM and BE being set in the DSM Strategic Issues proceeding; however, it is ambitious in its own right as it seeks to continue and expand the early investments we've made in BE while continuing to cost-effectively deliver strong energy efficiency and demand response savings. Specifically, the BE Plan is forecast to save nearly 3.5 million lifetime tons of carbon dioxide.

Q. HOW IS THE COMPANY FACILITATING THE TRANSITION TO ELECTRIC VEHICLES IN COLORADO?

A. Xcel Energy is working to help make one out of every five vehicles on the road by 2030 an electric vehicle ("EV") and to be the zero-carbon transportation fuel provider by the year 2050, across all areas where we provide electric service. Furthermore, Xcel Energy has an aspirational goal of having all customers able to access affordable EV charging where they live or within one mile. The 2030 goal closely aligns with the State of Colorado's own goal of having 940,000 EVs on the road by 2030, and can help create significant savings for drivers, help create downward pressure on rates for electric customers, and help reduce net emissions. Xcel Energy is working to achieve these goals through a suite of programs, collectively the 2021-2023 Transportation Electrification Plan ("TEP") approved in 2021, designed to help customers overcome upfront cost barriers, have access to tools and information on EVs and their benefits, and have access to time-varying rates and managed charging programs to help customers save money and align EV charging with times that are good for the grid.

As part of the TEP, the Company has also launched several partnership, research, and innovation projects to help further expand access to transportation electrification and to inform future TEPs. These projects include innovative electric car sharing programs, programs to support transportation electrification for medium- and heavy-duty vehicles, and a vehicle-to-X (with "X" referring to home, buildings, and/or the grid) demonstration. The Company has also established two commercial charging rates for EVs, the S-EV and S-EV-CPP rates, and two managed charging programs, Optimize Your Charge (a static program focused on setting charging schedules outside of peak hours) and Charging Perks (a dynamic or active load control program). These offerings provide customers more choices to suit their energy needs and provide strong incentives to charge at times when it's good for them and for the grid. The Company will continue to build on and advance these programs in the next TEP filing in 2023.

Q. AS PART OF THESE EFFORTS, IS THE COMPANY EXPANDING CLEAN ENERGY OPPORTUNITIES FOR DISADVANTAGED COMMUNITIES?

A. Yes, we are keenly aware of the need to ensure disadvantaged communities also have opportunities to participate in and are benefiting from the clean energy transition. There are several examples across Public Service's programs and territories that I will highlight below.

First, the aforementioned DSM & BE Plan include specific carve outs and offerings for income qualified ("IQ") customers. These programs offer low-to-no cost energy efficiency measures to qualifying customers and are forecasted to save customers over 29 GWh annually. The programs are implemented in partnership with Energy Outreach Colorado and include programs for single-family and multi-family homes as well as the non-profit agencies that provide support to income qualified customers. Within the single-family programs, the Company also provides health and safety measures that facilitate the installation of energy savings technologies while ensuring customers safe, efficient homes. In the future, the Company is looking at ways to make customer participation easier by streamlining or simplifying qualification processes thereby expanding access.

Next, the Company's TEP dedicates 15 percent of its budget to support IQ customers and disproportionately impacted ("DI") communities. Programs supported by this funding include: incentives for the purchase of EVs; incentives for the installation of chargers by residential customers or commercial customers that provide support to or jobs for IQ customers; and the installation of charging hubs within DI communities to expand charging access. The Company also regularly engages with DI communities and their representatives on program design and implementation to improve customer access to programs and expand the opportunity for all customers to benefit.

Finally, our recently approved Renewable Energy Plan, which brought together a wide array of diverse interests in a comprehensive and unopposed settlement agreement provides IQ customers and DI communities with several options for participation. This includes: the allocation of 2 MW of annual Solar*Rewards capacity; incentives to reduce the cost of new private solar installations; IQ/DI specific community solar gardens offerings; and increased outreach and engagement to IQ/DI groups to improve customer engagement and program design. This outreach also works hand-in-hand with the Company's outreach efforts for DSM and EVs.

Q. ARE THERE ADDITIONAL OPPORTUNITIES FOR THE COMPANY TO EXPAND ON THE CLEAN ENERGY TRANSITION GOING FORWARD, IN PARTNERSHIP WITH THE COMMISSION AND OTHER COLORADO STAKEHOLDERS?

A. Yes. The Infrastructure Investment and Jobs Act ("IIJA") and the Inflation Reduction Act ("IRA") will both provide opportunities to accelerate the clean energy transition and to mitigate the costs of transitioning to clean energy while meeting the Company's short and long term goals. Generally, these two pieces of legislation will open a number of programs under which the Company can seek federal funding in support of clean energy projects, and we are in the process of evaluating how to extract as much benefit to our customers as possible from these programs. However, it is important to note that these same programs are driving demand for the materials, supplies, and labor needed to implement clean energy projects, which has an offsetting effect on our capital and O&M project costs.

Additionally, there are a number of new tax provisions that will decrease the cost of new renewable projects and offer opportunities to make existing resources more economic for customers. Company witness Ms. Naomi Koch discusses the tax provisions of the IRA in more detail in her testimony.

The most immediate benefit to Public Service customers from the IRA will come through the transferability of production tax credits ("PTCs"), which offers the opportunity to monetize these credits, thus reducing the deferred tax asset associated with these credits beginning in 2023. Company witness Mr. Paul A. Johnson also discusses potential impacts on our cash flows. The potential monetization of credits offers potentially significant customer value, such that the Company will make a separate filing before the end of the year seeking approval of tariff modifications required to deliver these benefits to customers.

Q. DOES PUBLIC SERVICE CONTRIBUTE TO THE STATE'S ECONOMY IN OTHER WAYS?

A. Yes. We are one of the largest taxpayers and largest employers in the state. In 2021, the Company paid more than $225 million in property and use taxes to state and local governmental entities in Colorado, employed over 3,900 people, and spent over $510 million with local suppliers.

In addition, the Company has supported the Colorado economy by sourcing parts and materials locally, when possible. For example, the Vestas turbines that Public Service purchased for the Cheyenne Ridge and Rush Creek projects were manufactured in Colorado.

Q. DOES PUBLIC SERVICE PROVIDE SAFE AND RELIABLE ELECTRIC SERVICE?

Yes. As important as all of the Company's environmental and safety initiatives are, it is equally important to recognize that Public Service is also extremely good at its basic job, which is providing safe and reliable electric service at a reasonable cost.

Q. CAN YOU PROVIDE EXAMPLES OF OTHER WAYS THE COMPANY ENHANCES THE CUSTOMER EXPERIENCE IN ADDITION TO PROVIDING RELIABLE SERVICE AT REASONABLE COSTS?

A. Yes. In addition to enhancing customers' ability to access electric services that support the clean energy transition I described above, we are moving into a new era of reliability through implementation of the Advanced Grid Intelligence and Security ("AGIS") Initiative, which will change the way we identify and respond to outages, and which will facilitate more transparency for customers with respect to energy usage. As we near the end of the AGIS rollout, we are on the cusp of being able to provide customers with more data, enhancing the accuracy of meter reading and billing, and improving our insight into the distribution system. We have better voltage optimization capabilities, greater insight into energy usage, and more opportunities for customers to make efficient energy choices.

We are also taking steps to implement technology that will improve our customers' experiences with the Company. Our Customer Experience Transformation, or CXT, program managed by our Technology Services business area improved multiple aspects of customers' interaction with the Company, whether through MyAccount, mobile applications, or the Builders' Call Line. Improving these interactions with customers not only empowers them to use energy efficiently and cost-effectively, but also enhances customer satisfaction. We have also implemented information technology ("IT") projects that improve our ability to operate efficiently as well as our customer service.

Q. CAN YOU DESCRIBE ANY INVESTMENTS THAT PUBLIC SERVICE MAKES IN COLORADO IN ADDITION TO THOSE YOU HAVE ALREADY ADDRESSED?

A. Yes. In addition to the direct investment in infrastructure that I described above, which generates immediate jobs in the state, long-term employment at the Company's facilities, and increased tax bases for the taxing jurisdictions, we also invest in the communities we serve. We assist others in the community to provide a more attractive environment for not only our existing residents but also potential residents of this state. By being an active partner and creating an attractive energy option, we are able to attract businesses to our jurisdiction, which in turn brings more jobs, health, and vitality to all our communities.

More specifically, customer and community relations employees in Colorado manage a suite of programs and services for the communities we serve. The Xcel Energy Foundation provides over $1 million to nonprofit organizations within our Colorado service territory in the areas of STEM education, environment, economic sustainability, and access to arts and culture. In addition, over 2,800 Company employees and retirees volunteered over 25,000 hours across 323 nonprofits in 2021 within the community. Employees serve on the boards of directors of more than 100 business, civic, and nonprofit organizations in our service area. The goal is to ensure the communities in our service territories are healthy and vibrant places to live and work. Judging from the growth we are seeing in the Company's service territory, our efforts – combined with the efforts of innumerable other civic and business contributors in Colorado – are bearing fruit.

Q. IS THE COMPANY ALSO MAKING INVESTMENTS TO ENHANCE PUBLIC SAFETY?

A. Yes. Safety is a core value at Xcel Energy. We are committed to providing a safe work environment for our employees and are similarly dedicated to the safety of the public. As described in more detail by Company witness Mr. David C. Mino, significant components of our distribution system were installed in the 1950s and

1960s and are nearing the end of their useful lives. The replacement of aging assets is critical to ensuring reliable operations continue, and also critical to ensuring the operation of our distribution network is safe for our employees, customers, and communities. Unlike most of the transmission system the distribution system is not fully redundant such that system component failures can directly impact a customer's reliability. Distribution investments in Asset Health and Reliability are also being triggered by changes in the way that Public Service's customers use the distribution system. The distribution system is moving from exclusively one-way power flows to two-way power flows as customers are installing distributed energy resources ("DERs") (e.g., rooftop solar) on their homes and businesses, and the number of community solar gardens continues to grow. Consequently, the Asset Health and Reliability category is the Distribution area's largest capital budget category.

Q. HOW DOES THIS DISCUSSION FACTOR INTO CONSIDERATION OF THE ISSUES IN THIS RATE CASE?

A. Public Service is not simply a fee for service business; as a public utility, it is both providing a critical service and also making a difference in the communities it serves. By investing in the Company's electric generation, transmission, and distribution systems as well as encouraging wise energy usage among our customers, we are continuing to lead the clean energy transition from many perspectives. It is important to remember, however, that this work – both the services we provide and our community contributions, job creation, tax base, and policy development support – all depends on supporting and maintaining the financial integrity of the Company. Further, just as there is a desire in Colorado to promote beneficial electrification, there is a need to finance and facilitate the investments necessary for the electric transmission and distribution systems to support that load. Particularly as inflation drives up our costs and market pressures drive up the competition for materials, services, labor, and capital in the marketplace, this rate case is of utmost importance to maintain the Company's financial integrity.

B. The Need for this Rate Case

1. Phase I Revenue Deficiency

Q. PLEASE SUMMARIZE THE COMPANY'S REQUESTED CHANGE IN BASE RATE REVENUE IN THIS PROCEEDING.

A. As illustrated in Attachment SPB-1 to my Direct Testimony, the Company requests that the Commission approve an overall base rate revenue requirement for Public Service's retail electric operations of $2,452.7 million, which has been calculated based upon a Test Year ending December 31, 2023. When compared to the forecasted 2023 revenue under present rates of $2,140.5 million, the Company's total requested change in base rate revenue is $312.2 million. However, approximately $49.9 million of this total base rate revenue increase consists of amounts previously recovered through riders, resulting in a net base revenue change of $262.3 million.

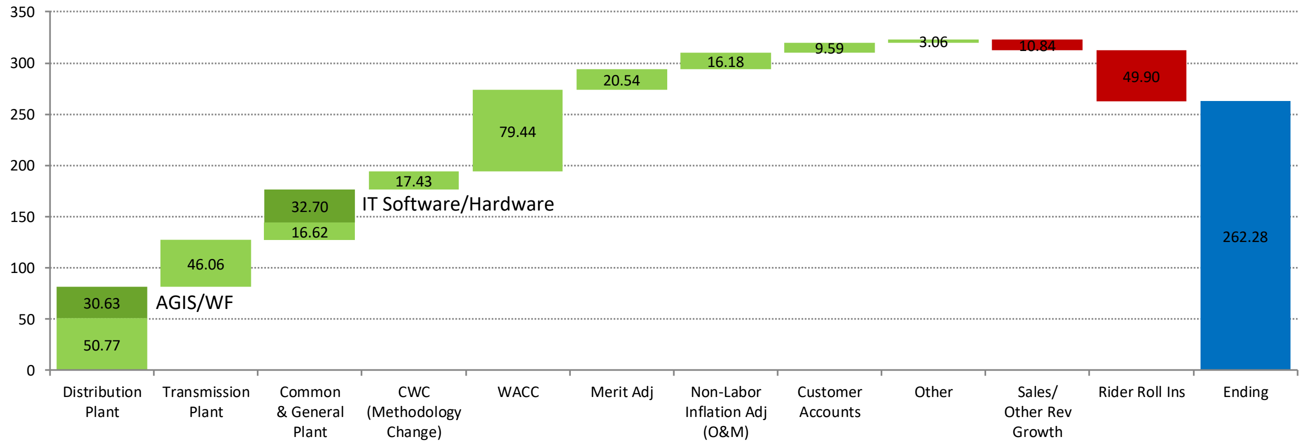
Q. TO WHAT EXTENT DOES THE NET BASE REVENUE DEFICIENCY RELATE TO PROJECTS AND COSTS PREVIOUSLY PRESENTED TO THE COMMISSION, OTHER THAN THOSE INCLUDED IN RIDERS?

A. The change in revenue requirements associated with AGIS and Wildfire activities from the cost of service that rates are currently based on to the proposed Test Year in this proceeding is $22.0 million. This represents activities that were approved in prior proceedings to be tracked and deferred, and is the change in the baseline amounts being requested for these two programs from what is currently in base rates.

Q. CAN YOU ILLUSTRATE THE DRIVERS OF THE TEST YEAR REVENUE DEFICIENCY?

A. Yes. Figure SPB-D-1 below summarizes the drivers of our revenue requirement request in this proceeding. As illustrated in Figure SPB-D-1 and as I describe in the next section of my Direct Testimony, the primary drivers fall into three broad categories of costs: Capital investment increases, primarily in our Distribution system, Transmission system, and IT; O&M increases, necessary primarily to properly compensate our employees and to address inflation; and the need for our WACC to reflect current market conditions. These increases are offset somewhat by sales growth, as depicted below:

Figure SPB-D-1:
Base Rate Deficiency Drivers
2021 Phase I Rate Case to Proposed Revenue Change



Q. PLEASE SUMMARIZE THE PLANT ADDITIONS SINCE THE COMPANY'S 2021 ELECTRIC PHASE I.

A. Table SPB-D-1 below summarizes plant additions since the 2021 Test Year by function. A majority of these additions are operational investments in the Company's electric system.

Table SPB-D-1:
Summary of Capital Additions Net of Retirements ($ Millions)

	Total
Steam Production	($225,966,210)
Hydro Production	$75,327,253
Other Production	$302,419,385
Transmission	$685,273,066
Distribution	$1,053,301,806
Electric General and Intangible	$223,788,003
Common General and Intangible	$383,945,841
Total	$2,557,718,908

Q. ARE THESE PLANT ADDITIONS CONSISTENT WITH HISTORICAL CAPITAL ADDITIONS?

A. Yes. The level of overall capital additions has remained relatively consistent, with the six-, eight-, and ten-year Compound Average Growth Rates ("CAGR") being around 6 percent, as illustrated in Company witness Mr. Arthur P. Freitas's Attachment APF-8. Within this broader growth rate, the Company's capital investments in Distribution and IT are particular drivers of the revenue deficiency in this proceeding.

Q. PLEASE DESCRIBE THE PARTICULAR INCREASES IN DISTRIBUTION, TRANSMISSION, AND IT CAPITAL COSTS.

A. In general, investments in the distribution and transmission system and in our information technology needs are driven by necessary replacement of aging equipment, population growth and new service requests, and capacity upgrades necessitated by increasing demand.

Q. WHAT IS DRIVING THE INCREASED INVESTMENTS IN THE DISTRIBUTION SYSTEM?

A. As Company witness Mr. Mino explains in his Direct Testimony, many of the Company's distribution assets were installed or constructed in the 1950 and 1960s, and they are nearing the end of their service lives. Public Service must either replace or refurbish the assets to ensure the safety and reliability of the distribution grid; as such, investments in Asset Health and Reliability are the largest component of Distribution costs.

Investments also support changes in the way that Public Service's customers use the distribution system. The distribution system is moving from exclusively one-way power flows to two-way power flows as customers are installing DERs (e.g., rooftop solar) on their homes and businesses. Additionally, the number of community solar gardens that are interconnected to the Company's system continues to grow. Accommodating these DERs requires that equipment be robust enough and have sufficient capacity to maintain proper voltage levels when these new resources come online. In addition, increasing penetration of DERs could result in greater wear on already aging facilities and can also prompt the need for changes to protection schemes and equipment. A distribution system that is able to accommodate increasing amounts of DER will contribute to Public Service meeting its emission-reductions goals.

In many areas, growth in the number of customers results in the need to increase the capacity of the distribution system. Additional usage in some areas of the system has required the Company to build new substations, install larger transformers, and construct new feeders. The anticipated increase in electric vehicles will also put additional strain on the existing system.

Collectively, these distribution-related investments account for approximately $1.1 billion of plant additions, or 41 percent, of the change in plant additions driving the change in rate base since the Company's last case. Maintaining a safe and reliable distribution system leaves little discretion regarding the amounts and timing of these investments.

Q. WHAT IS DRIVING THE INCREMENTAL INCREASED TRANSMISSION CAPITAL INVESTMENTS?

A. As Company witness Mr. Gilbert Y. Flores describes in his Direct Testimony, Transmission makes capital investments to maintain and improve the reliability of the transmission system. Approximately 80 percent of the investments in 2022 and 2023 are in the categories of Asset Renewal, Regional Expansion, and investments necessary to meet Reliability Requirements. An important part of maintaining the reliability of the transmission system is replacing or refurbishing facilities that are in poor condition or have reached the end of their life. In 2022 and 2023, Transmission will be making increased investments in Asset Renewal projects to address aging transmission facilities that are in need of replacement or refurbishment to reduce the likelihood of critical failures and sustained outages and help ensure long-term system reliability.

In 2022 and 2023, Transmission will also be making investments in several large Regional Expansion projects that are needed to provide greater system reliability and to provide the necessary transmission capacity to accommodate greater renewable generation. These projects include the Greenwood to Denver Terminal 230 kilovolt ("kV") Transmission Project and Uprate Projects and the Canal Crossing – Goose Creek 345 kV transmission line project (part of the Company's Power Pathway Project). As a final capital driver, Transmission will also be completing a number of Reliability Requirement projects that are needed to ensure that the transmission system is in compliance with all North American Electric Reliability Corporation ("NERC") reliability standards.

Q. WHAT IS DRIVING THE INCREASED NEED FOR CAPITAL INVESTMENTS IN INFORMATION TECHNOLOGY?

A. As discussed by Company witness Ms. Megan N. Scheller, IT investments have become increasingly critical to the work of utilities from almost every perspective – whether it be systems controls such as generation plant controls, customer outage management, or Supervisory Control and Data Acquisition (or SCADA) investments; foundational technology like employees' hardware and software needs, data management, and cybersecurity protections; customer IT support such as Xcel Energy's website, MyAccount, and mobile apps; and support for fundamental corporate functions like accounting, billing systems, and human resources management. Additionally, utility company operations and business models are evolving as the energy industry itself transforms, requiring technologies that further ensure operational resilience during extreme weather conditions, business resilience to cyber-attacks as well as customer demand for information and interaction, and agility during the clean energy transition. "Keeping the lights on" requires investment in technology that helps ensure customer, employee, and public safety; manages the reliability of the system; and supports business continuity.

On top of the increasing dependence of the utility business (and society in general) on IT, Public Service must make investments specific to the needs of its customers and service territory. Many of the Company's IT systems are aging and require replacement. The Company is also investing in newer technology to support system and customer demands for information and more efficient energy management, such as the IT components of the AGIS initiative, electric vehicle support, and fundamental IT infrastructure including data centers and more efficient worker support in the fields. At the same time, in the last few years Xcel Energy has invested in improving customers' experience with the utility.

Q. ARE THERE OTHER CONSIDERATIONS THAT DRIVE IT INVESTMENT LEVELS?

A. Yes. As described by Ms. Scheller, a large portion of the incremental Aging Technology and Cybersecurity IT capital investments have short useful lives – 15 years or less, and in some cases only six or seven years. This is due to the speed at which technology changes and therefore becomes obsolete or at-risk, and requires upgrades, replacement, or alternative solutions. This turnover can drive investment, but it also is relevant to the Commission's approved means of cost recovery: If, on average, the Company only begins to recover a return of and on capital investments two or more years after the project is placed in service, due to regulatory lag, then Public Service is routinely losing the ability to recover anywhere from roughly 15 to 40 percent of its costs associated with these projects. This lag on IT investments is inconsistent with other utility investments while IT investments are just as imperative to serving customers as longer lived utility assets.

Q. IS THE COMPANY MAKING ANY PROPOSALS IN THIS CASE TO ADDRESS THE LAG ON THESE IMPORTANT IT ASSETS WITH SHORTER LIVES?

A. Yes. As discussed in more detail by Company witnesses Ms. Scheller and Ms. Marci A. McKoane, the Company is proposing an IT Deferral for costs associated with Aging Technology and Cybersecurity IT capital investments. Specifically, Public Service proposes to track and defer the depreciation expense and return on these IT capital investments beginning January 1, 2024 or the end of the Test Year approved by the Commission, for potential recovery in future cases. The assets that would be eligible for deferral under this proposal are unique in terms of their short depreciable lives, which differentiates them from typical utility assets with long lives. The very nature of these assets creates a situation where without more current recovery or a deferral mechanism, the Company is vulnerable to significant under recovery at a time when the level of investment in these areas is increasing. This proposal has the benefits of both allowing the Company to defer the costs of capital investment for more complete future recovery, while also enabling parties to examine the actual deferred costs for potential future recovery.

Q. PLEASE DISCUSS HOW O&M COSTS ARE AFFECTING THE NEED FOR THIS RATE CASE.

A. In addition to capital investments, other factors that are not wholly within the Company's control, such as employee costs and inflation, are driving up our O&M costs. This is reflected in our Test Year O&M as compared to operating expense levels in the 2021 Electric Phase I, as set forth in Table SPB-D-2 below:

**Table SPB-D-2:
O&M Expense
($ Millions)**

	21AL-0317E Test Year	2023 TY	Difference 21AL-0317E to 2023 TY
Production	$187.5	$187.1	($0.3)
Transmission	$52.2	$51.1	($1.1)
Regional Markets	$0.1	$0.4	$0.3
Distribution	$136.4	$140.5	$4.1
Customer Accounts	$49.3	$66.0	$16.7
Customer Service	$91.2	$91.4	$0.2
Sales	$2.6	$2.8	$0.2
A&G	$138.9	$160.5	$21.7
Total O&M	$658.2	$699.8	$41.6

Q. HOW DO THESE OVERALL INCREASES IN O&M COSTS COMPARE TO THE COMPOUND AVERAGE GROWTH RATE?

A. The ten-year CAGR of O&M expense is approximately 0.98 percent, as shown in Mr. Freitas's Attachment APF-7, significantly lower than the approximately 6 percent CAGR in capital additions over the same period. This demonstrates the Company has been able to make the investments needed to continue providing safe and reliable service while controlling expense changes.

Q. WHAT IS CAUSING THE INCREASE IN EMPLOYEE COSTS?

A. There are multiple factors driving up the costs of properly compensating Public Service employees, which are discussed in detail by Company witness Mr. Michael P. Deselich. At a high level, the key drivers are an anticipated increase in the base wages for our bargaining unit employees based on the current collective bargaining agreement that expires in May of 2023, and potentially higher wage increases to be effective June 1, 2023 under a new agreement. For non-bargaining employees, Public Service incurred an average 4.0 percent base wage increase effective March 1, 2022, and anticipates an additional average base wage increase of 4.0 percent effective March 1, 2023. While somewhat higher in amount that in past cases, these wage increases are consistent with the broader marketplace (as Mr. Deselich describes) and it is consistent with prior cases for these wage increases to be included in the cost of service.

Q. PLEASE DISCUSS HOW INFLATION IS AFFECTING PUBLIC SERVICE'S NON-LABOR O&M?

A. It is no secret that inflationary pressures have been rising across the United States to levels that have not been experienced for decades. Company witness Mr. Sangram S. Bhosale describes the impact of inflation on Public Service, as well as supply chain limitations that drive up demand and therefore costs of providing service to Public Service's customers. Other Business Area witnesses further describe the effects of inflation and material and services constraints on their respective businesses. These inflationary pressures impact a wide range of Public Service's costs of providing electric service, from access to and the cost of contractors, materials used in the maintenance of system infrastructure, fuels for our transportation fleet, chemicals necessary to the operation of Public Service's generation fleet, and other supplies. Company witness Mr. Freitas then discusses the application of non-labor inflationary factors to the Company's actual O&M through June 30, 2022, to reflect market conditions for the period rates will be in effect.

Q. FINALLY, HOW ARE INCREASES IN THE COST OF CAPITAL DRIVING THE NEED FOR THIS RATE CASE?

A. As discussed by Company witness Mr. Johnson, rising interest rates are driving up the cost of debt across financial markets, including the Company's long-term and short-term debt necessary to finance the business. While impacts on the cost of debt are not dramatic at this time, due to the timing of the Company's debt issuances, its use of a 13-month average for establishing the cost of debt, and the relatively small amount of short-term debt in the Company's capital structure, these rising costs are driving up the overall WACC.

Likewise, Company witness Ms. Ann E. Bulkley discusses the change in Treasury Rates, interest rates, and other market conditions driving the need for a higher return on equity ("ROE") in this proceeding. Understanding the Commission's interest in gradualism, in our 2019 Electric Phase I rate case Public Service's authorized ROE was reduced from 9.83 percent to 9.30 percent within a single rate case. At this time, inflation is currently at its highest level seen in approximately 40 years. Interest rates have also increased significantly from pandemic-related lows seen in 2020, and are expected to continue to increase in direct response to the Federal Reserve's activities. It is necessary and appropriate to increase the Company's ROE materially under these conditions, just as the Commission reduced the Company's ROE in 2019 in relation to declining interest rates and low inflation.

Finally, the Company appreciates the Commission's move to a year-end rate base as applied to the Company's historical test year in our recent 2022 Gas

Rate Case. At the same time, the continuing effects of regulatory lag, increased capital investment, and lack of returns on deferrals all continue to reduce Public Service's opportunity to earn its authorized return and increase Public Service's risk relative to its peers with greater access to riders, current and forecasted test years, returns on deferrals, and more constructive decoupling programs. Accordingly, Public Service requests an ROE commensurate with both the current marketplace and its relative risk, or 10.25 percent.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR DISCUSSION OF THE PHASE I OVERVIEW?

A. As I indicated earlier in my Direct Testimony, this base rate case represents one more step in a series of Commission proceedings that have facilitated our efforts to advance the clean-energy transition and to modernize the grid. The primary driver of the change in base rate revenue presented in this proceeding is related to the change in rate base since the Company's last case. As summarized in Table SPB-D-1 above, the rate base change has arisen largely from our obligation to serve new customers and to provide safe and reliable electric service. The investments presented in this case are the investments needed to continue delivering clean, safe, and reliable energy for our customers and the State of Colorado.

2. Customer Impacts

Q. WILL PUBLIC SERVICE'S RATES REMAIN REASONABLE, EVEN WITH ITS REQUESTED INCREASES?

A. Yes. Even with the increase the Company seeks in this case, Public Service's average residential bills will remain below the national average rate for comparable utilities. Those below-average rates do not happen by accident – Public Service continuously searches for ways to control costs, as evidenced by the fact that its overall O&M expense levels remained largely flat over the last decade while capital investment has grown exponentially. Maintaining affordable rates for customers is a high priority for the Company. I discuss the overall impact to customer rates in this section of my testimony.

Q. HAS THE COMPANY ANALYZED THE SPECIFIC EFFECT OF ITS PROPOSED RATE INCREASE BY CLASS?

A. Yes. Table SPB-D-3 shows the bill impacts by rate class if the Company's proposed rates are compared to the currently effective rates.

Table SPB-D-3

2022 Electric Rate Case - Phase I vs Currently Effective Rates				
Average Monthly Bill Impact				
	Current	Proposed	Monthly $ Change	Monthly % Change
Residential - R	$89.35	$96.69	$7.33	8.20%
Commercial - C	$130.79	$140.95	$10.16	7.77%
Secondary General - SG	$2,582.70	$2,764.38	$181.68	7.03%
Primary General - PG	$44,898.23	$47,610.52	$2,712.28	6.04%
Transmission General - TG	$561,240.95	$589,663.34	$28,422.38	5.06%

Q. EARLIER YOU DISCUSSED THE COMPANY'S ROLE IN SERVING CUSTOMERS AND CONTAINING COSTS. IS THE COMPANY PROPOSING ANY ADDITIONAL ACTIONS IN THIS CASE TO PROTECT CUSTOMERS?

A. Yes. In Section III.B below, I discuss the Company's proposal for an earnings sharing mechanism that would protect customers by ensuring the Company's earnings do not exceed a reasonable range from its authorized ROE in this proceeding.

C. Introduction of Company Witnesses

Q. PLEASE INTRODUCE THE WITNESSES WHO ARE SUPPORTING THE COMPANY'S REQUESTS IN THIS PROCEEDING.

A. In addition to my Direct Testimony, the Company is presenting Direct Testimony from 19 witnesses in support of the requests in this proceeding. In Table SPB-D-4 below, I provide the name of each additional witness and a brief description of the Direct Testimony provided by the witness.

Table SPB-D-4:
Introduction of Company Witnesses

Witness	***Testimony Topics***
Marci A. McKoane	• Describes the Company's compliance with prior commitments and Commission Orders; • Supports the Company's proposed tariffs; • Supports the Company's request for the continuation of certain trackers and regulatory assets as well as the addition of a new deferral of certain IT costs and a new regulatory proceedings cost tracker that includes rate case expense; • Supports the amortization period for deferrals; and • Supports the Company's proposed treatment of net gain on sale of Zuni Tank Farm property.

Witness	***Testimony Topics***
Paul A. Johnson	• Discusses financial integrity, its importance to public utilities and its stakeholders, and the benefits of accessing capital markets to provide capital for utility expenditures; • Discusses the credit rating agencies' evaluation criteria and provides an assessment of Public Service's financial integrity; • Presents and supports the capital structure for calendar year 2023; • Presents and supports the Company's cost of long-term and short-term debt; and • Presents and supports the recommended WACC.
Ann E. Bulkley	• Provides a recommendation for and supports the Company's requested ROE; and • Provides an assessment of the reasonableness of the proposed capital structure to be used for ratemaking purposes.
Mark P. Moeller	• Sponsors the plant-in-service and other plant-related balances in the TY; and • Supports the level of requested depreciation and amortization expenses.
Adam R. Dietenberger	• Supports the Company's total budgeting and forecasting, and the reasonableness of the Company's management of its overall costs; and • Supports the 2022 and 2023 plant-in-service additions included in the cost of service, as well as Test Year O&M, for Shared Services other than Technology Services.
Sangram S. Bhosale	• Discusses the impacts of inflation and supply chain constraints on the Company's business, including non-labor O&M.
Kyle L. Williams	• Supports the Generation Business Area capital additions for 2022 and 2023; and • Supports certain O&M expense included in the cost of service.
Gilbert Y. Flores	• Supports Transmission capital additions for 2022 and 2023; • Supports certain O&M expenses included in the cost of service; and • Describes the Company's use of third-party wheeling service to transmit power to customers.

Witness	***Testimony Topics***
David C. Mino	• Supports the Company's Distribution Business Planning; • Supports the Distribution Business Area's capital additions for 2022 and 2023; • Supports certain O&M expenses included in the cost of service; and • Supports the Distribution components of the AGIS initiative.
Kristopher R. Farruggia	• Supports the 2022 and 2023 Transmission and Distribution capital additions associated with the Wildfire Mitigation Plan ("WMP"); and • Supports certain Transmission and Distribution WMP O&M expenses included in the cost of service.
Megan N. Scheller	• Discusses the Technology Services Business Area and the expanding IT needs of the Electric Utility; and • Supports the Company's request for an IT Deferral for certain IT capital.
Michael O. Remington	• Supports Technology Services' capital additions for 2022 and 2023; • Supports certain O&M expenses included in the cost of service; and • Supports the Technology Services components of the AGIS initiative.
Michael P. Deselich	• Explains that the purpose of the Company's Total Rewards Program is to attract, retain, and motivate employees by offering competitive compensation packages; • Describes and supports the base pay element of the overall compensation package; • Describes and supports the incentive compensation elements of the overall compensation package; and • Describes the initiatives taken by Public Service to control compensation and benefit costs.

Witness	***Testimony Topics***
Richard R. Schrubbe	• Presents and supports the Company's request to recover its reasonable and necessary pension and benefit expenses; and • Describes the Company's prepaid pension asset and its prepaid retiree medical asset and explains why those assets should be included in rate base and should earn a return at the Company's WACC.
Nicole L. Doyle	• Describes the Xcel Energy holding company structure and organizational structure; • Describes XES, its history and operations and the allocation methodologies; • Explains the cost allocation rules; and • Sponsors the Company's Cost Assignment and Allocation Manual and the Company's Fully Distributed Cost Study.
Naomi Koch	• Supports calculation of income tax expense as though Public Service had depreciated its assets on a straight-line book basis; • Supports the return of excess ADIT to customers; • Discusses the Inflation Reduction Act; and • Addresses the level of property tax expense included in the cost of service.
John M. Goodenough	• Supports weather normalization of the Company's Test Year sales and billing demand; and • Discusses historical customer and sales growth trends and the factors driving that growth.
Scott A. Watson	• Supports the Company's lead lag study and cash working capital methodology and calculation.
Arthur P. Freitas	• Presents the Company's cost of service study and explains the rationales for many of the adjustments included in the cost of service study; • Supports the application of inflationary adjustments to non-labor O&M; • Supports the Company's proposed rate base convention; and • Supports the Company's proposed amortizations of deferred costs

III. RATEMAKING POLICY DISCUSSION

A. Relationship Between the Test Year and Just and Reasonable Rates

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

A. In this section of my testimony, I first describe the Company's proposed Test Year and how Public Service developed its overall proposals and recommendations in this proceeding. I then support the reasonableness of the Company's Test Year proposal, discussing the importance of taking incremental steps to reduce regulatory lag, the reasonable accuracy of the Company's overall forecasts, and the customer protections the Company is proposing.

1. The Components of the Company's Proposed Test Year

Q. WHAT TEST YEAR IS THE COMPANY PROPOSING IN THIS CASE?

A. The Company is proposing a Test Year that reflects rate base using a 13-month average convention for the period ending December 31, 2023. Plant balances are based on actual plant additions through June 31, 2022 plus forecasted additions through December 31, 2023. The Test Year also consists of forecasted sales revenue for 2023 and actual O&M expense for the 12 months ended June 30, 2022 with certain known and measurable adjustments and inflationary increases I discuss later in my testimony. The Test Year revenue requirement is calculated based on a ROE of 10.25 percent, an equity ratio of 55.70 percent and an overall WACC of 7.45 percent. Company witness Ms. Bulkley supports the Company's requested ROE, while Company witness Mr. Johnson supports the Company's WACC, including the components thereof. Various Public Service witnesses support the O&M, sales revenue, and capital additions that result in the Test Year cost of service, and Mr. Freitas provides more detail regarding the development of the Test Year revenue requirement.

Q. CAN YOU EXPLAIN AT A HIGH LEVEL HOW THE COMPANY PROPOSES TO QUANTIFY THE TEST YEAR RATE BASE?

A. Yes. For purposes of establishing rate base, the Company proposes to include all capital costs related to assets placed in service on or before December 31, 2023. In effect, the rate base would include the actual plant-in-services balance as of June 30, 2022, plus the forecasted capital additions and retirements for the remainder of 2022 and 2023. For the Test Year, which is calendar year 2023, Public Service proposes to calculate rate base using a 13-month average rate base, with the 13 months being December 2022 through December 2023.

Q. HOW DOES THE COMPANY PROPOSE TO ESTABLISH O&M COSTS FOR THE TEST YEAR?

A. Public Service has primarily relied on actual O&M through June 30, 2022, adjusted for specific individual changes, and labor and non-labor inflation, as a reasonable representation of expected O&M in the rate effective period. The forecasted changes are supported by various Company witnesses or reports from third parties, such as Public Service's actuary, Willis Towers Watson ("Willis") and IHS Markit. We have also provided detailed analysis of the impacts Public Service has experienced, specifically in the testimony of Mr. Deselich (for labor) and Mr. Bhosale (for materials, supplies, contract labor, fuel, and other non-labor costs). Company witness Mr. Freitas explains how these adjustments are factored into the Company's cost of service in this proceeding.

Q. IS THE COMPANY ALSO PROVIDING AN INFORMATIONAL HTY?

A. Yes. For informational purposes, the Company is also providing a 2022 informational historical test year (the 2022 “Informational Historical Test Year” or “2022 IHTY”) cost of service for the 12 months ended June 30, 2022. The 2022 IHTY also reflects certain known and measurable adjustments, including a sales forecast and capital adjustment to bring revenues and rate base forward to December 31, 2022. The Company will update the 2022 IHTY capital adjustment to actuals as soon as the data is available (likely first quarter 2023).

Q. WHY IS THE COMPANY PROVIDING AN IHTY WITH ADJUSTMENTS TO THE END OF 2022?

A. In our recent 2022 Combined Gas Rate Case, we filed our case in early 2022 with an HTY reflecting actual data through June 30, 2021. Almost immediately, parties began questioning when the Company would provide data through year-end 2021 and questioning why the Company did not provide year-end data in its filing. The Company explained in that case that it takes time for year-end data to become available and incorporated into a revenue requirement study. While that is the case here as well, the 2022 IHTY is designed to provide the most current information practicable with the filing, and to provide updated actual data for these adjustments as soon as it can be compiled into a revenue requirement model. Mr. Freitas discusses the development of the 2022 IHTY in more detail in his Direct Testimony.

2. The Company's Proposed Test Year is a Reasonable Step Toward More Current Cost Recovery

Q. WHY IS THE COMPANY PROPOSING TO INCLUDE SOME CAPITAL FORECASTING IN THE TEST YEAR, GIVEN THE COMMISSION'S PAST RELIANCE ON HISTORICAL TEST YEARS?

A. Conceptually, this proposal is not very different from what the parties agreed to in settlement in the 2021 Electric Phase I, which resulted in a calendar year 2021 Test Year with 13-month average rate base for rates going into effect in early 2022. We appreciate that in our recent 2022 Gas Rate Case, the Commission recognized that regulatory lag has a detrimental impact on the Company. But we also recognize that in that case, the Commission was not yet fully comfortable with forecasted capital within a test year – particularly for a gas utility in the context of the Clean Heat Transition. Here, we know that the Company will need to continue to make investments in the electric system precisely to support safe and reliable service and meet environmental goals. We also know that although the Company's request for a 2023 Test Year with some forecasted rate base is not a big leap conceptually, the continued reliance on historical rate base has a significant impact on the Company's ability to earn its authorized return. We therefore propose the Test Year in this proceeding in an effort to make incremental steps to reduce regulatory lag.

Further, this proposal aligns with the forward-looking nature of Colorado's electric policy goals, described earlier in my Direct Testimony. Public Service's ambitious goals to reduce carbon emissions by 85 percent by 2030 and to provide

100 percent carbon free electricity by 2050 cannot be achieved by looking solely at past investments; they require Public Service to continue to plan to transition its fleet and add distribution and transmission capacity. The Company's efforts in this regard are consistent with the Commission's encouragement in our 2022 Gas Rate Case to continually align the level of utility investment with state policy goals. Public Service's Electric Utility is achieving these visionary goals, and is proposing incremental improvements to align ratemaking accordingly.

Q. WHY DID THE COMPANY PROPOSE A SINGLE TEST YEAR IN THIS CASE?

A. Public Service has taken a more conservative approach to establishing the Test Year in this case as compared to recent proposals, while still seeking reasonable means of reducing the effects of regulatory lag. This approach was deliberate to help bridge the gap on test year proposals between the Company and intervening parties. While we could have proposed a fully forecasted multi-year rate plan, we are attempting with this proposal to begin a discussion where alternatives to HTYs can be explored. The Company firmly believes that more forward-looking rate making is just as critical to achieving clean energy goals as the extensive forward looking planning being completed across multiple other Electric proceedings.

Q. WHAT MAKES THE TEST YEAR MORE CONSERVATIVE THAN PAST PROPOSALS?

A. First, we are only proposing a singular test year. Second, while our Test Year is not solely historical, we are limiting forecasting by proposing a calendar year 2023 Test Year that is premised largely on historical O&M plus inflation, and providing actual capital through June 30, 2022. Next, an average rate base methodology is proposed when rates will not be effective until September of 2023, which inherently builds 8 months of lag into our proposal. Finally, pairing the Test Year with an earnings sharing mechanism protects customers in the rate-effective period and should ease any concerns about differences in actuals from forecasts.

In addition, the singular Test Year the Company proposes here is intended to simplify the rate case discussion while enabling the parties to continue broader ratemaking policy discussions that began in our 2021 Phase I Electric rate case. It is difficult to undertake broader policy discussions around ratemaking in the context of a rate case, as such discussions tend to be bound up in advocacy positions and desired outcomes for the particular case at hand. Public Service believes that current rate case filing framework discussions are best addressed in a miscellaneous docket before the Commission, where topics around effective, efficient, and reasonable ratemaking can be undertaken separate from any individual utility's pending case. Such discussions can further serve as the premise for a rulemaking to encapsulate and codify concrete rules around more current cost recovery, rate filing packages, performance incentive mechanisms, and timelines to promote regulatory efficiency.

Q. WHY IS IT IMPORTANT TO MOVE TO A MORE CURRENT COST RECOVERY CONSTRUCT?

A. An important goal of utility ratemaking is that the recovery of costs through rates during a specific period should match the utility's prudently incurred costs during that same period. Thus, when setting rates, it is generally desirable to set rates that, *on an expected basis*, will yield revenues equal to the prudently incurred cost of service – including a reasonable return on equity capital.

If rates are based on investments from an historical period, then they may be far removed from the rates required to recover costs during the year(s) the rates actually are in effect, resulting in “regulatory lag.” This distortion will occur regardless of the precision of the test-year costs and revenues. Even if they are verified with 100 percent accuracy, they do not capture the inevitable changes to either the Company’s costs of providing service or customer billing determinants in later years.

The use of forecasts mitigates this problem, particularly when the new rates are implemented when the Test Year begins or soon thereafter. Even excellent forecasts are never 100 percent accurate, but they can still yield rates that are more accurate during the period in which they are in effect than rates based on totally precise costs and revenues for the wrong period.

Q. PLEASE DESCRIBE THE CONCEPT OF REGULATORY LAG.

A. At the highest level, the concept of regulatory lag refers to the time difference between when a utility incurs a cost and when that cost is incorporated into rates. This can occur, for example, when an asset is placed in service but not incorporated into rate base until the Company files a rate case and rates from that case take effect.

Q. IS REGULATORY LAG INHERENT IN THE REGULATORY PROCESS?

A. Generally, yes. Some amount of regulatory lag is inherent in the regulatory process, and both the Company and customers tolerate it to the extent they are able. Regulatory lag becomes much more difficult to manage if the lag is persistent, involves large dollars, or both.

Q. WHAT IS THE CONSEQUENCE OF AN UNREASONABLE AMOUNT OF REGULATORY LAG?

A. An unreasonable amount of regulatory lag can frustrate a utility's opportunity to earn its authorized return. For example, the use of an HTY and the associated unreasonable amount of regulatory lag has denied Public Service a reasonable opportunity to earn its authorized return, even when paired with rider recovery opportunities over the last decade.

Q. ARE THERE OTHER REGULATORY LIMITATIONS ON COST RECOVERY THAT COMPOUND THE CHALLENGES ASSOCIATED WITH REGULATORY LAG?

A. Yes. For a variety of reasons there are numerous costs that Public Service removes from the cost of service in general rate proceedings. These costs are primarily removed due to historical regulatory treatment; however, the Company deems these costs necessary to operate effectively and thus they continue to be incurred. The removal of these costs in setting rates results in the actual return to shareholders being lower than the authorized return, before any other earnings erosion is considered. Table SPB-D-5 summarizes the costs Public Service is not seeking in this proceeding that will be borne by shareholders.

TABLE SPB-D-5
Regulatory Leakage
(Twelve Mos. Ended June 30, 2022)

Cost	Revenue Requirement Impact
Cap AIP at Target	$1,163,626
Aviation Expenses	$1,125,899
Advertising Expenses	$2,587,800
Investor Relations Expenses	$165,312
Board of Directors Equity Comp	$276,099
Donations	$5,991,845
Civic and Political Expenses	$1,123,088
Total	**$12,433,669**

Q. DOESN'T REGULATORY LAG IMPOSE AN INCENTIVE FOR THE COMPANY TO CONTROL COSTS?

A. Not by itself, and in fact can have the opposite effect. If a utility's costs were declining or revenues were growing more than costs between an historical test year and more current or forecasted test year, regulatory lag would equate to higher rates as compared to current cost recovery. Further, when costs tend to increase year over year, regulatory lag delays or reduces recovery of whatever costs the Company incurred – regardless of the degree to which the utility was or was not able to control the costs. Thus, some intervenors' long-standing argument that regulatory lag leads to incentives for utility cost control is really saying only that reducing the revenue requirement encourages cost controls. This is not a reasonable approach. There is no doubt that a utility seeks an opportunity to both recover its reasonable costs and earn a reasonable return, which is fundamentally the regulatory compact. But reducing the revenue requirement for its own sake is not appropriate when the revenue requirement is designed to recover reasonably incurred costs plus a reasonable return on investments the utility has made to serve customers. In fact, this argument in support of deploying regulatory lag to incentivize cost controls is arguably inconsistent with the regulatory compact.

Q. IS THERE ANY EVIDENCE THAT FORECASTED DATA IS A BETTER REPRESENTATION OF THE PERIOD RATES WILL BE IN EFFECT THAN HISTORICAL DATA?

A. Yes. It is indisputable that Public Service's electric business has required increased investment annually over the past decade and the testimony provided in this case illustrates that will continue into the foreseeable future. As shown in Mr. Freitas's Attachment APF-8, the 10-year CAGR of gross plant is just over 6 percent. Numerous witnesses in this proceeding discuss the need for continued investment to lead the clean energy transition while providing safe and reliable service to customers. The investment proposed in this proceeding is also aligned with the historical trend in Attachment APF-8. Considering the historic trends and future projections, forecasted data certainly provides a better representation on which to set rates for the rate effective period than historic data could.

Q. HAS THE COMMISSION HISTORICALLY AGREED THAT THE INVESTMENTS PUBLIC SERVICE HAS MADE IN THE ELECTRIC SYSTEM ARE PRUDENT?

A. Yes. There are very few examples of investments being disallowed for prudency over the past decade and even further back in time. While the Commission has largely relied on actual costs through HTYs to set rates, all of the investment has been deemed prudent and approved for recovery in those test years.

Q. WHAT CONCLUSIONS CAN BE DRAWN FROM THE HISTORIC INVESTMENT TRENDS AND COMMISSION APPROVAL OF THESE INVESTMENTS?

A. In an environment requiring increasing need for investment year over year, setting rates based on HTYs will continue to preclude the Company from a reasonable opportunity to recover prudent and necessary costs of providing electric service, and will support rates that do not reflect all the investments that will be serving customers in the rate-effective period.

Q. ARE THERE PARTS OF THE COLORADO RATEMAKING PROCESS THAT HAVE RELIED ALMOST EXCLUSIVELY ON FORECASTS OF CIRCUMSTANCES FOR THE PERIODS RATES WILL BE IN EFFECT?

A. Yes. A key example is the ROE, which has long been based on forward-looking models of likely financial conditions for many years into the future. The very purpose of models like the Discounted Cash Flow, for example, is to assess likely future returns for purposes of setting an ROE in the context of a present test year. Such methods have been the basis for establishing authorized ROEs for regulated utilities across the country for decades. Further, it goes without saying that ROE models involve judgments and that actual future market conditions are highly unlikely to precisely match any current predictions; nonetheless, these models are widely regarded as reliable, appropriate, and time-tested.

Likewise, capital forecasts are based on robust, tested methodologies described in detail in the Company's Direct Testimony and are managed carefully through effective business area and project management. As with an ROE model, actual capital investment is unlikely to precisely match each component of the forecast. This is simply a fundamental (and appropriate) function of the utility's obligation to prioritize and re-prioritize work to meet emerging customer needs, respond to changing conditions, and incorporate new information into its decision-making as information becomes available.

Q. WILL THE COMPANY EVER BE ABLE TO GUARANTEE THAT ACTUAL INDIVIDUAL PROJECTS OR PROJECT COSTS WILL ALIGN WITH BUDGETS OR FORECASTS DEVELOPED MONTHS IN ADVANCE?

A. No, and nor should the Commission want them to match. Rather, it is in customers' interest for the Company to constantly re-evaluate and re-prioritize projects to respond to emerging customer or system needs and higher priorities, to delay projects that are no longer needed, and to re-assess whether projects may be more financially feasible if accelerated or delayed. This is not only beneficial to customers, but part of the Company's responsibility to manage its business and its obligations to serve. And while individual project and even Business Area budgets are adjusted to meet system and customer needs, these adjustments typically result in immaterial changes to the overall revenue requirement of the system. As such, these same dynamics should not prevent the Commission from permitting some level of forecasted capital costs in the Test Year, consistent with how state commissions across the country approach ratemaking.

Q. ARE THERE OTHER REASONS WHY IT IS APPROPRIATE TO APPROVE RATES BASED ON A TEST YEAR BUDGET THAT INCLUDES FORECASTS?

A. Yes. The Commission is charged with setting just and reasonable rates as a whole. While individual capital projects serve as the basis for building a capital budget, rates are set based on the overall rate base and revenue requirement, which typically do not vary substantially from an overall budget. Additionally, the reasonableness of the Company's overall rate base and revenue requirement can be tested based on the kinds of work in which the Company is engaging, reasonable levels of investment to meet the utility's obligation to provide safe and reliable service, and the Company's management practices. In this instance, Company capital witnesses explain that the Company's capital budgeting process allows the business areas to determine their spending requirements, have their assumptions challenged and refined to align with overall Company vision and Operating Company initiatives, resulting in a well-balanced plan that can be relied upon to set rates.

Perhaps just as importantly for ratemaking, the Company's expenditures during the future period when rates will be in effect necessarily will not match the investments made in past years as I discussed above. Thus, a backward-looking "audit" of historical costs does little to align with or provide the Commission with insight into future investments. It also reduces the value of the test year as representative of the likely circumstances during the period rates will be in effect.

Furthermore, multiple state commissions permit and rely on forecasted test years, for good reason. Information is provided that allows stakeholders to evaluate the planned costs, just as they evaluate planned projects in a CPCN, advance rider filing, or other project notification. This evaluation can include assessment of planned scope of work, need for the project, planned design and costs to the extent known, regardless of whether the project is complete, in progress, or planned. This approach has the benefit of giving the utility feedback on a project before it is in service, allowing the Commission and other stakeholders the opportunity to weigh in on investments before the money is spent and the infrastructure is built. To the extent the Commission wants to impact future utility investment via rate cases, the best means of doing so is to evaluate planned investments rather than solely completed projects.

Additionally, there is momentum across the country to move to more current and forward-looking recovery to align with aggressive clean energy policy goals. Attachment SPB-3 to my Direct Testimony provides an overview of how many other state Commissions handle these matters. Because this clean energy transition is requiring, and will continue to require, significant investment by utilities, forward-looking ratemaking will better align investment with cost recovery and will allow for regulatory review of, and input into, the planning process. While Colorado is at the forefront of the clean energy future and Xcel Energy is leading that transition with aggressive goals unlike any other utility, there remains a significant lag on cost recovery reform in Colorado to align with the aggressive clean energy goals.

Q. CAN YOU EXPLAIN FURTHER HOW PUBLIC SERVICE'S LEADERSHIP ON CLEAN-ENERGY ISSUES IS RELATED TO THE TEST YEAR THAT THE COMMISSION ADOPTS IN THIS CASE?

A. Yes. If the Commission wishes to encourage Public Service to continue providing safe and reliable electric service at a reasonable cost while also taking a leadership role in reducing carbon emissions and promoting economic development, the best way to do that is to provide a reasonable opportunity for the Company to earn its authorized ROE on those investments. A test year that is close in time to the period rates will be in effect provides that opportunity; an HTY does not for all the reasons I discuss above as well as the additional business risk an HTY creates, as discussed by Company witness Ms. Bulkley.

Q. HOW CAN CONCERNS ABOUT VERIFYING ACTUAL UTILITY INVESTMENTS BE ADDRESSED?

A. The first step is to focus more on the Company's overall proposed rates in comparison to factors like national averages, affordability, achievement of performance goals, and the types of items on which a Company is utilizing resources, and less on merely auditing projects the Company has already undertaken. As I noted above, for example, Public Service already has one of the lowest average residential electric bills in the country. At the same time, Public Service deploys a limited amount of capital annually. There is always more demand for capital than the Company actually deploys. At the same time, Public Service manages projects to the overall established budgets, illustrating discipline to the budget even as individual projects necessarily evolve to meet system and customer needs.

The second step is to recognize that Public Service provides the same support throughout this proceeding for both the projects that have been placed in service or will be placed in service between the end of our last case through the end of the Test Year. That is, whether individual projects are forecasted, underway, or complete, the Company provides planning information, cost data, information about the need for the work, and the like for key projects, and further provides additional support in discovery upon request. Thus, individual projects can be evaluated to the extent the Commission feels this is needed. And as I previously noted, completing this evaluation before projects are complete provides the parties and the Commission with more opportunities to weigh in on whether projects should continue – before they are complete, consistent with the more forward-looking nature of Commission planning generally.

Third, it is important to be clear that past costs can be audited even in a future test year, as with the Comanche 3 investigation resulting in several recommendations in our 2021 Electric Phase I. Public Service is not suggesting that the Commission should simply trust that the Company will spend money reasonably; rather, there can be no doubt that while individual project information will change, the Company generally carries out the same types of work year over year, focusing on the needs of the electric system and of customers. The Commission can evaluate the overall level of capital and forecasts in a rate case for the Test Year proposed, including projects newly completed or placed in service after the record closed in a prior rate case. In this case, the Commission and parties can review the Company’s actual 2022 and 2023 capital data in our next rate case for prudency.

This framework provides the flexibility for the Company to manage its work consistent with its obligations to customers, which evolve during the period rates are being set. Requiring that projects be fully completed before they can be included in a test year solely on the grounds that individual project forecasts may vary from actuals has the effect of penalizing the utility for effectively managing to changing customer and system demands. Taken to its logical conclusion, the historical "audit" approach also incentivizes the Company to implement projects that were planned even if they are not ultimately needed, solely to establish that the actuals will closely match budgets. Public Service is not taking this approach to its deployment of capital, but also continues to seek more current cost recovery in recognition that such a construct is more aligned with forward-looking regulatory planning.

Finally, another step, which is not mutually exclusive of others, is to implement customer protections such as the Earnings Test the Company is proposing in this proceeding. I discuss this proposal more in the next section of my Direct Testimony.

Q. TO WHAT EXTENT DOES A TEST YEAR INCORPORATING SOME FORECASTED CAPITAL INVESTMENTS STILL INVOLVE REGULATORY LAG?

A. The Test Year Public Service is proposing in this proceeding is not fully forecasted, and even if it were, it would still impose regulatory lag on the utility. First, the Company's proposed O&M is based on actuals through June 30, 2022 with certain known and measurable adjustments and inflationary increases. As such, it is only the capital that is partially forecasted, and only for the incremental capital added during the 18 months before the end of the Test Year. But even the capital proposals are based on information available when the case is filed – that is, information as of the fourth quarter of 2022. In the current increasing inflationary environment, the time it takes to complete a rate case alone imposes regulatory lag on the Company. Finally, the proposed Test Year utilizes an average rate base despite rates from this case most likely being effective in the latter part of 2023. A true FTY would have a rate effective date on January 1 of the Test Year.

Q. WHAT IS YOUR CONCLUSION REGARDING THE COMPANY'S TEST YEAR PROPOSAL AND THE COMMISSION'S HISTORICAL FOCUS ON REGULATORY LAG?

A. The Company is proposing a Test Year that takes a modest, incremental step toward reducing regulatory lag while maintaining some lag and including customer protections. We make this carefully constructed proposal not only to recommend that the Commission allow a further, gradual reduction in regulatory lag, but also to encourage the parties to engage on reasonable means of setting rates that do not default to historical test years. As opposed to historical data, the Company's proposed Test Year offers a more accurate representation of the costs to serve customers in the rate-effective period, and the Commission can rely on the forecasted capital given the robust budgeting process described across multiple Company witnesses. Approval of the proposed Test Year in this proceeding will put Public Service in a strong financial position to execute on leading the clean energy transition and meeting Colorado's energy goals as quickly as possible.

B. Customer Protection

Q. IS THE COMPANY PROPOSING ANY CUSTOMER PROTECTIONS IN RELATION TO ITS OVERALL PROPOSALS IN THIS CASE?

A. Yes. As I noted above, there are already customer protections embedded in the rate case process, including the opportunity to examine both past and current investments and costs in this and future proceedings. To further support its Test Year proposal in this proceeding and ensure it comes with appropriate customer protections, Public Service is taking the further step in proposing an Earnings Test.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED EARNINGS SHARING ADJUSTMENT ("ESA").

A. If the Commission adopts the Test Year as discussed in my testimony the Company is proposing an Earnings Test beginning with calendar year 2024 and continuing until rates become effective from the next rate case with the following sharing thresholds and percentages:

**Table SPB-D-6:
Earnings Sharing Adjustment**

Earned ROE	Customer Share	Company Share
Up to Authorized ROE + 50 bps*	0%	100%
Authorized ROE + 51- 150 bps	50%	50%
Authorized ROE + 151 bps or higher	100%	0%

****BASIS POINTS ("BPS")***

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED EARNINGS TEST AND ESA.

A. The Company would submit a report each year by April 30 detailing its returns for the previous calendar year. The first report would be due on April 30, 2025 and reflect the results of calendar year 2024. The returns would be derived consistent with the regulatory principles adopted by the Commission in this proceeding, as detailed further by Mr. Freitas in his Direct Testimony. For each year the Company would absorb all under-earnings below the authorized return in this proceeding. There would be a 50 basis point dead band above the authorized return where the Company would retain earnings. The Company and customers would share equally any amounts related to earnings of 51 to 150 basis points of earnings above the authorized return. All amounts related to earnings in excess of 150 basis points over the allowed return would be fully returned to customers.

To the extent the Earnings Test results in sharing with customers, the Company will file an Advice Letter seeking to put into effect, subject to true-up, a GRSA sufficient to refund to customers the proposed earnings sharing. The earnings sharing GRSA proposed by the Company will be effective August 1st of each year through July 31st of the following year. Trial Staff of the Commission ("Staff") and any other person that disputes the Company's Earnings Test information will file a notice with the Commission identifying any matters in the Company's earnings test filing with which a party takes issue and the basis for the dispute, no later than June 15th in any year. If all persons disputing the earnings sharing amount and the Company cannot resolve all of the differences by July

15th, then all remaining disputes will be detailed in a written notice submitted to the Commission no later than August 1st, together with a proposed procedural schedule for addressing such issues. Any over-collection of revenues resulting from the differences between the GRSA ultimately approved by the Commission and the GRSA implemented on August 1st will be refunded to customers.

Q. WHY IS THE COMPANY PROPOSING AN EARNINGS TEST AND ESA AS AN APPROPRIATE CUSTOMER PROTECTION?

A. Public Service has proposed various customer protections in its rate cases, including step years with capital true-ups in its recent 2022 Gas Rate Case. We received questions in that proceeding (and some criticism or implication) that we should have offered a full earnings test to cover all aspects of the business, rather than just capital. This proposal accomplishes that. Additionally, the ESA does incentivize the Company to control costs, while also providing an opportunity for customers to share in the benefits if Public Service is successful. I note that this mechanism is carefully tailored to protect customers, as there is no downside for customers if the Company does not earn its authorized ROE.

Q. HAS THE COMPANY PREVIOUSLY BEEN SUBJECT TO AN EARNINGS SHARING MECHANISM?

A. Yes, in several instances for the Electric Department, the Company was subject to an Electric Department earnings test sharing mechanism as approved by the Commission in Decision No. C12-0494, in Proceeding No. 11AL-947E, that measured the Company's earnings for calendar years 2012 through 2014. In addition, in Proceeding No. 14AL-0660E, the Company agreed through a

Settlement Agreement to extend the current Electric Department earnings test sharing mechanism for calendar years 2015 through 2017. The Commission approved this extension, as well as the sharing thresholds and percentages and earnings test governance principles, in Decision No. C15-0292. In addition, from 1997 through 2007, the Company was subject to an Electric Department earnings test sharing mechanism.

Q. HOW DOES THIS PROPOSAL INTERRELATE WITH THE COMPANY'S REVENUE DECOUPLING ADJUSTMENT ("RDA") MECHANISM?

A. The Company's current RDA pilot measures the difference between a baseline of fixed cost recovery authorized by the Commission and actual fixed costs recovered in base rates.[1] These differences are calculated on a calendar-year basis, with 2023 being the final year of measurement.[2] The proposed ESA in this case would not take effect until January 1, 2024, meaning there is no overlap between the fixed cost recovery authorized through the RDA pilot and the proposed ESA.

Q. WOULD THE COMPANY STILL PROPOSE OR SUPPORT AN EARNINGS TEST OR ESA IF THE COMMISSION WERE TO ADOPT AN HTY?

A. No. An earnings test is a customer protection mechanism paired with the use of forecasts to set rates, and would not be necessary or customary under an HTY.

[1] In this proceeding, the Company proposes to re-set the RDA baseline effective with final rates.

[2] While 2023 is the final year for measuring differences between baseline of fixed cost recovery authorized by the Commission and actual fixed costs recovered in base rates, those differences could be recovered from or returned to customers through RDA rates that will be effective beyond 2023. In addition, the RDA pilot includes a true-up to address over- or under-recovery of amounts collected through the RDA rate.

Q. WOULD IT MAKE SENSE FOR THE COMMISSION TO ESTABLISH A WACC WITHOUT A SPECIFIC ROE UNDER THIS PROPOSAL?

A. If the Commission chose this approach consistent with the most recent Phase 1 Gas case and also adopted the proposed earnings sharing mechanism, it would be necessary to specify an ROE for purposes of calculating the earnings sharing bands under the ESA.

IV. INCREASING EFFICIENCY OF THE RATEMAKING PROCESS

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

A. In this section of my testimony I discuss steps the Company and its stakeholders have taken since our 2021 Electric Phase I rate case to improve the efficiency of retail ratemaking in Colorado. I also identify certain stakeholder requests for additional information in this case or in recent rate cases, which the Company is voluntarily providing in this case.

Q. WHAT STEPS HAS THE COMPANY TAKEN WITH STAKEHOLDERS SINCE THE LAST RATE CASE TO DISCUSS INCREASING THE EFFICIENCY OF THE RATEMAKING PROCESS?

A. As part of the 2021 Electric Phase I Rate Case, the Settling Parties agreed to work together prior to the next filed rate case to develop a rate filing package and procedures.[3] To meet this requirement, the Company has held two meetings to date where all parties from that case were invited to attend. Prior to the first meeting, the Company reached out to Staff and the Colorado Office of the Utility Consumer Advocate ("UCA") individually for their initial reactions to the rate filing package and procedures and brought those as a starting point to guide discussions at the first meeting, which occurred on September 16, 2022. The second meeting occurred on October 14, 2022. Both meetings involved engaging conversations with parties and were well attended.

[3] Proceeding No. 21AL-0317E, Decision No. C22-0178 at ¶ 52 (issued on March 16, 2022).

Q. DID THE COMPANY TAKE ANY IMMEDIATE ACTION BASED ON THESE DISCUSSIONS?

A. Yes. Based on these discussions it became clear to the Company that multiple parties wanted the Phase I and Phase II rate cases to be staggered and not be filed together, as the Company had initially planned for. To balance these concerns, and to achieve a more optimal outcome for all stakeholders, the Company filed a Motion for a one-time variance from its requirement that the Company file a Phase II rate case no later than December 31, 2022, as reflected in Decision No. C22-0178, and clarified by Decision No. C22-0278.[4] As I noted previously, the Commission ultimately permitted Public Service to file staggered Phase I and Phase II rate cases, with the Phase II rate case filed by May 15, 2023.

Q. HAS THE COMPANY ALSO INCLUDED CERTAIN ADDITIONAL INFORMATION REQUESTED FROM STAKEHOLDERS IN THIS RATE CASE FILING?

A. Yes. The Company and stakeholders discussed how the Company could best provide clarity with respect to the various requests in a rate case and clear line of sight for all cost of service adjustments from the model to the witness supporting

[4] Decision No. C22-0178 (Mailed Date: March 24, 2022) approved the Unopposed and Comprehensive Settlement Agreement (Except as to One Issue) (the “2021 Electric Phase I Settlement”). As part of that approval, the Commission required the Company to file a Phase II rate case no later than six months following the effective date of Decision No. C22-0178. Decision No. C22-0178 at 32, Ordering Paragraph 7. In Decision No. C22-0278 (Mailed Date; May 4, 2022), the Commission clarified the Company is obligated to file a Phase II rate case no later than six months following the effective date of its General Rate Schedule Adjustment True-Up. Decision No. C22-0278 at 6, ¶ 24. The General Rate Schedule Adjustment True-Up became effective July 1, 2022. See Amended Advice No. 1887 in Proceeding No. 22AL-0229E (filed June 1, 2022). Therefore, the Company is required to file a new Phase II rate case on or before December 31, 2022.

the adjustment. To provide this additional clarity, the Company has done the following:

- Prepared Attachment SPB-1, which lists the recommendations in the case and which witness supports each item;
- Prepared Attachment APF-12, which details the adjustments the Company is proposing in its Test Year cost of service and traces the adjustments to the cost of service model and the witness supporting the adjustment;
- Prepared Attachment APF-13, a summary of regulatory assets and liabilities; and
- Provided additional information and variance analysis on the Company's budgeting and forecasting process in the Direct Testimony of Adam R. Dietenberger.

The Company will continue to work on any additional requests that will be included in the upcoming Phase II rate case filing.

Q. IS THE COMPANY PROVIDING INFORMATION IN THIS CASE THAT FOLLOWS FROM PAST COMMISSION DECISIONS?

A. Yes. Company witness Ms. McKoane provides information regarding Commission requirements from past rate cases and other proceedings that are relevant to this proceeding, and identifies how the Company is providing the information.

Q. DOES THE COMPANY ALSO ADDRESS COMPLIANCE REQUIREMENTS IN ITS DIRECT CASE?

A. Yes. Ms. McKoane provides a schedule of applicable compliance requirements that also identifies how each item is being addressed in this case. As with each rate case filing, the Company strives to provide complete, detailed information to the best of our ability.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend that the Commission authorize a base rate revenue increase of $312.2 million (or $262.3 million net of amounts previously recovered through riders), continuation or implementation of the Company's requested trackers and deferrals, and approval of the necessary tariff updates to implement the Company's requests. I also recommend approval of the Company's proposed Earnings Test and ESA consistent with the Company's Test Year proposal in this case.

As supported in my Direct Testimony and the Direct Testimony of the Company's additional witnesses, these requests balance the Company's need for rate relief to maintain its financial integrity as it seeks to continue leading the clean energy transition, with customers' interest in reasonable costs of service, and results in just and reasonable rates. Our proposed Test Year carefully aligns base rate cost recovery with investments needed to serve customers and achieve the policy goals of the State of Colorado. Our requests further present an opportunity to incrementally advance ratemaking in Colorado while accelerating the efficiency of the ratemaking process. Thus, the requests of the Company in this case are just, reasonable, and in the public interest, and should be approved.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Steven P. Berman

As the Regional Vice President of Regulatory and Pricing, I am responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service. My duties include the design and implementation of Public Service's regulatory strategy and programs, and directing and supervising Public Service's regulatory activities, including oversight of rate cases and other related filings. Those duties include: administration of regulatory tariffs, rules, and forms; regulatory case direction and administration; compliance reporting; complaint response; and working with regulatory staffs and agencies.

I accepted the RVP position with Public Service in November 2022 after holding the Director, Regulatory Administration role since January 2020. From April 2015 to January 2020, I was Manager of Revenue Analysis and 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.

Prior to this time, I worked for Xcel Energy and Colorado Springs Utilities in progressively more responsible roles. 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 working in the utility industry, I held various positions in marketing and finance after graduating college in 1999 and moving into the utility industry in 2006.

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

* * * *

IN THE MATTER OF ADVICE LETTER NO. 1906-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 8-ELECTRIC TARIFF TO REVISE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL ELECTRIC RATE SCHEDULES, AND MAKE OTHER TARIFF PROPOSALS EFFECTIVE DECEMBER 31, 2022.	**) PROCEEDING NO. 22AL-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 22nd day of November, 2022.

Steven P. Berman
Regional Vice President of Regulatory Administration

Subscribed and sworn to before me this 22nd day of Nov., 2022.

Hannah Ahrendt
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID# 20224026062
MY COMMISSION EXPIRES JULY 5, 2026

Notary Public

My Commission expires July 5, 2026