**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 TARIFF PROPOSALS EFFECTIVE DECEMBER 31, 2022.	**) PROCEEDING NO. 22AL-XXXXE**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF GILBERT Y. FLORES</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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I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gilbert Y. Flores. 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 Xcel Energy Services Inc. ("XES") as the Manager of Transmission Planning for Public Service Company of Colorado ("Public Service" or the "Company"). XES is a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy") and provides an array of support services to Public Service and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

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

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As the Manager of Transmission Planning for Public Service Company of Colorado, I am responsible for overseeing the engineering group responsible for planning Public Service's transmission system and also responsible for the development of Transmission budgets, regulatory compliance, and portions of the Operations & Maintenance ("O&M") associated with Public Service's transmission system. I also oversee various aspects of transmission policy and manage participation in key regional Public Service transmission projects, as well as other regional projects on and adjacent to Public Service's transmission system. This includes conducting strategic analyses for potential transmission projects, evaluating and negotiating joint agreements, and engaging in stakeholder outreach. A description of my qualifications, duties, and responsibilities is set forth in my Statement of Qualifications at the conclusion of my Direct Testimony.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to support the Transmission Business Area (or "Transmission") capital additions and operation and maintenance ("O&M") expenses that are allocated to Public Service retail electric and included in the 2023 test year ("Test Year") cost of service that is presented by Company witness Mr. Arthur P. Freitas. The Company's last electric rate case was Proceeding No. 21AL-0317E (the "2021 Electric Phase I"), in which a test year ending December 31, 2021 was approved as agreed to in a unanimous settlement. I therefore also provide support for Transmission's capital additions placed into service since the Company's 2021 Electric Phase I, from January 1, 2022 through year-end 2023.

The Company's Transmission plant additions since the 2021 Electric Phase I through December 31, 2023 total $606.5 million. Company witness Mr. Mark P. Moeller has calculated the monthly plant balances to develop the plant-related roll forward, which is in turn used by Mr. Freitas to incorporate the 13-month average plant in service balances into the Test Year cost of service. These amounts do not include any plant additions associated with the Company's Wildfire Mitigation Plan ("WMP"), which is supported and discussed by Company witness Mr. Kristopher R. Farruggia.

I also support the $28.3 million in Transmission's O&M included in the Test Year. Transmission's O&M in this rate case is based on actual O&M expenses for the 12 months ended June 30, 2022 with adjustments to set a level of O&M expenses that is representative of the level expected when rates are in effect. Company witnesses Mr. Steven P. Berman and Mr. Freitas support the Company's overall Test Year development.

I also describe Public Service's use of third-party wheeling service to transmit power to serve its customers, as well as the costs for these services, and I support the adjustments for Transmission Wheeling Services included in the Test Year.

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

A. Yes, I am sponsoring Attachments GYF-1 through GYF-7, which were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment GYF-1: Capital Additions for January 1, 2021 – December

31, 2023;

- Attachment GYF-2: July 1, 2021 through June 30, 2022 Transmission Operations and Maintenance Costs by Cost Element;
- Attachment GYF-3: July 1, 2021 through June 30, 2022 Transmission Operations and Maintenance Costs by FERC Account;
- Attachment GYF-4: Public Service Wheeling Transactions;
- Attachment GYF-5C: Confidential DCP High Point Project Costs;
- Attachment GYF-5: Public DCP High Point Project Costs;
- Attachment GYF-6: Greenwood to Denver Terminal ("GDT") 230 kV Transmission Project and Uprate Project Costs; and
- Attachment GYF-7: Voltage Control Facilities Project Costs.

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

A. I recommend that the Colorado Public Utilities Commission ("Commission") approve the Company's 2022-2023 Transmission Business Area capital additions and the Transmission Business Area's Test Year O&M expenses, as set forth in my Direct Testimony and in the cost of service presented by Mr. Freitas. Finally, I recommend the Commission include the Test Year adjustments for Transmission Wheeling Services in the Company's cost of service.

II. TRANSMISSION BUSINESS AREA OVERVIEW, FUNCTIONS, AND ACTIVITIES

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

A. The purpose of this section of my Direct Testimony is to provide an overview of Public Service's Transmission Business Area functions and activities.

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

A. Public Service is a vertically integrated electric utility that owns and operates electric transmission facilities in Colorado. The Company uses its transmission system to deliver energy from our generating resources (both owned and purchased) to our wholesale and large retail customers, and to the Company's distribution facilities, which are used to provide service to most of our retail customers. Public Service's transmission system comprises approximately 4,985 circuit miles of transmission lines. The transmission lines are rated at voltages between 44 kilovolt ("kV") and 345 kV. Public Service's transmission system includes many lines that are jointly-owned with neighboring systems, such as Tri-State Generation and Transmission Association, Inc. ("Tri-State") and the Western Area Power Administration ("WAPA"). The Company's 242 transmission and distribution substations are also used to deliver electric energy to customers.

Q. PLEASE DESCRIBE THE TRANSMISSION BUSINESS AREA.

A. The Transmission Business Area is responsible for the planning, construction, operation, and maintenance of the electric transmission facilities necessary to meet the current and future energy needs of our customers in a safe and reliable manner. The Transmission Business Area is focused on ensuring that the Company's transmission facilities are reliable, resilient, and able to accommodate an increasingly diverse and dispersed number of electric generators.

Q. PLEASE DESCRIBE THE DEPARTMENTS WITHIN THE COMPANY'S TRANSMISSION BUSINESS AREA AND THEIR KEY FUNCTIONS.

A. There are six departments within the Company's Transmission Business Area. The key functions of these departments are as follows:

- *Asset management* is responsible for substation field engineering, which includes routine and emergency maintenance and operational activities for all Public Service substations. The organization also provides field implementation of certain North American Electric Reliability Corporation ("NERC") and Critical Infrastructure Protection ("CIP") compliance activities in addition to commissioning new substation facilities. Commissioning of new substation facilities involves ensuring that our substation facilities meet Federal Energy Regulatory Commission ("FERC"), NERC, and Company operational and reliability requirements. The Quality Assurance/Quality Control ("QA/QC") process performed by Company engineers and technicians tests the equipment and control systems of our electric substations prior to energizing. This department is also responsible for system sustainability. System sustainability provides, among other things, electric material and design standards for the design, construction, and maintenance of our Transmission assets by interpreting industry standards such as American National Standards Institute ("ANSI") standards. System sustainability is also responsible for developing Public Service's reliability-centered maintenance programs that ensure the health and reliability of existing assets. These processes establish the baseline performance expected by our operations and maintenance organizations and confirm the performance for compliance standards.

- *Transmission strategy and planning* is responsible for: (1) life cycle planning, transmission system planning, and associated capital budgeting; (2) negotiating transmission service-related contracts with generators, transmission owners, and distribution utilities; and (3) resolving wholesale customer transmissions service concerns. In addition, this department manages Xcel Energy's participation in key regional projects throughout its service territories, as well as other regional projects on and adjacent to the Company's transmission systems, including the Public Service transmission system. This group is also responsible for the Company's policies and procedures in the competitive transmission acquisition processes.

- *Field operations* provides field services for construction, maintenance, and emergency repairs for transmission assets.

- *Transmission portfolio delivery* is responsible for managing capital projects, programs, and portfolios, including designing and engineering transmission assets, managing third-party contractors, and securing and managing transmission land rights.

- *System operations* is primarily responsible for the NERC Balancing Authority and Transmission Operations function for all Company transmission systems.

- *Transmission business operations* directs the Transmission Business Area's efforts pertaining to compliance with NERC requirements and directs business performance achievement efforts.

III. TRANSMISSION CAPITAL BUDGET, PROJECT SELECTION, AND FUNDING

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

A. The purpose of this section of my Direct Testimony is to provide an overview of the Transmission Business Area's capital budgeting process, project development, and project management processes. I also explain how the Company keeps the Commission informed regarding its Transmission projects.

Q. GENERALLY SPEAKING, WHAT TYPE OF CAPITAL INVESTMENTS ARE MADE BY THE TRANSMISSION BUSINESS AREA?

A. Transmission's capital investments include transmission line components such as, poles, conductors, switches, and land rights for transmission line easements. Transmission also makes investments in substation components such as transformers, capacitor banks, reactors, circuit breakers, relay and communication equipment, remote terminals, and land rights for new substations. Transmission's capital projects generally fall into two major types. The first consists of large capital projects that are often multi-year projects. These projects are capital-intensive and are aimed at improving the transmission system, upgrading existing facilities to meet NERC compliance requirements and to accommodate new generation, replacing aging facilities, and making improvements to communication infrastructure and physical security.

In addition to these larger, multi-year capital projects, the Transmission Business Area also completes many smaller capital projects each year. These smaller projects comprise a majority of the total number of projects that

Transmission completes each year. Some examples of smaller projects include replacement of one to two structures or cross-arms due to age, condition, or storm damage.

Q. HOW DOES TRANSMISSION CATEGORIZE ITS CAPITAL INVESTMENTS?

A. Transmission's capital projects generally fall into six capital budget categories depending on the main purpose of the project. These capital budget categories are: (1) Asset Renewal; (2) Reliability Requirement; (3) Regional Expansion; (4) Interconnection; (5) Physical Security and Resiliency; and (6) Communication Infrastructure. I provide more detail on each of these categories below.

- *Asset Renewal:* This category is primarily for managing the health and performance of transmission assets. The main goal of the investments in this category is to ensure that critical assets including transmission lines, substations, and other related assets meet reliability and capacity requirements, while minimizing life-cycle costs. This includes planned replacement of aging transmission lines and substation equipment, and unplanned replacement of damaged lines or equipment. This category also includes investments in necessary tools to support capital projects and line relocations due to road projects.

- *Regional Expansion:* This category includes major high voltage transmission line projects that serve multiple needs including regional and local reliability and renewable energy development. Generally, these are multi-year initiatives and the types of projects for which the Company seeks a Certificate of Public Convenience and Necessity ("CPCN") from the Commission especially for projects with voltage ratings of 230 kV or greater.

- *Reliability Requirement:* Reliability projects are constructed to ensure that the transmission system is compliant with all NERC reliability standards. Compliance with NERC reliability standards is mandatory for all users, owners, and operators of the Bulk Electric System ("BES"). FERC, NERC, and regional reliability entities monitor and enforce NERC compliance. The Transmission organization is continually studying the transmission system to assess compliance with NERC standards. These studies analyze the impacts of forecasted load growth, existing and anticipated generation needs, and new generation interconnections to determine whether transmission upgrades are necessary.

- *Interconnection:* This category includes projects that the Company is required to construct under the FERC Open Access Transmission Tariff ("OATT") to accommodate interconnection requests from generators, other transmission providers for their transmission lines, and new load.

- *Physical Security and Resiliency:* There are two critical aspects to this grouping of projects: physical security and grid resiliency. Physical security addresses physical threats to utility infrastructure, such as transmission lines and substation equipment. Grid resiliency addresses the Company's ability to monitor and recover from incidents occurring on our system to limit disturbances that may leave our service territory exposed to prolonged outages, oftentimes by adding redundancy to our transmission system. This category also includes projects intended to address NERC standards related to security and grid resiliency.

- *Communication Infrastructure:* This category includes the fiber optic and communication network infrastructure buildout on the existing transmission system to improve communication connectivity for all business areas. This infrastructure allows the digital transfer of Supervisory Control and Data Acquisition ("SCADA") data and tele-protection services. As telecommunication service providers are retiring the existing obsolete analog connections, Transmission will be continuing our efforts to privatize our communication network infrastructure across the Company's service territory.

Q. PLEASE DESCRIBE HOW PUBLIC SERVICE DEVELOPS ITS CAPITAL BUDGET FOR ITS TRANSMISSION BUSINESS AREA.

A. The annual capital budget for Transmission is based on collaboration between corporate management of overall Company finances and the business needs that are identified by Transmission. Company witness Mr. Adam R. Dietenberger explains how the Company establishes overall business area capital spending guidelines and budgets based on financing availability, specific needs of business areas, and the overall needs of the Company. Mr. Dietenberger also explains that generally, there are more projects and work to be done than Xcel Energy has the capacity to fund, resulting in the need for prioritization and assessment across business areas and operating companies that ultimately results in a capital budget specific to the Company and the Transmission Business Area.

Q. PLEASE PROVIDE A SUMMARY OF TRANSMISSION'S CAPITAL BUDGETING PROCESS.

A. Transmission employs a "bottom-up" budgeting process to identify the capital projects that we need to complete within a specific year for our business area. All of our capital projects are executed under the Capital Project Governance Process. This governance process has policies and procedures in place that enable Transmission to prioritize and balance our budget such that we appropriately allocate funds. Our capital budgeting process includes four main steps:

1. Identification of potential projects;
2. Vetting of potential projects;
3. Prioritization of potential projects; and
4. Rebalancing and reprioritization of projects based on corporate budget requirements.

Q. PLEASE EXPLAIN HOW THE TRANSMISSION BUSINESS AREA RANKS AND FUNDS PROJECTS.

A. The Transmission Business Area uses a multi-step project lifecycle process that takes a project from the identification of a need, through mitigation development, alternative evaluation, preliminary scope development, and cost estimating, before concluding with final scope approval.

The project originator develops a proposed statement of work for each project – typically consisting of the proposed scope, project description, necessity description, alternatives and proposed option, desired completion date, consequences of not pursuing the project, and a basic electric circuit diagram.

Multi-disciplinary project teams are established with members who have functional skills such as financial management, project management and controls, design and engineering, system operations, construction, siting and land rights, scheduling, and planning. Each project team is assembled to review the proposed scope and evaluate alternatives, and then to identify additional details for the preliminary scope and schedule, along with supporting documentation. The project team may prepare multiple higher-level estimates to assess alternative system solutions, and weigh proposed solutions against other alternatives. This determines the most reasonable electrical and financial solution that meets transmission needs as part of the overall planning process. The estimates for each proposed project may be included in the latter years of the Transmission Business Area’s budget.

Once the conceptual electric solutions are identified, the Transmission Business Area reviews the capital projects to select those projects that best meet the system’s reliability needs and contractual and regulatory obligations. The Transmission Business Area then assesses risks for the projects and captures project requirements, project scope, preliminary cost estimates, and required in-service date information.

All capital projects are then prioritized. Key drivers for risk prioritization strategy include reliability, regulatory compliance, contractual agreements, and economic, security, and other risk factors.

Q. WHAT PROCESS DOES THE TRANSMISSION BUSINESS AREA FOLLOW TO MANAGE AND CONTAIN ITS CAPITAL COSTS?

A. The Transmission Business Area reviews capital projects on a monthly basis after budget approval to compare the monthly budget to actual funds spent, and forecast at completion to total project budget. The Transmission Business Area performs a monthly project-forecasting exercise to ensure we have a steady and dependable flow of financial information regarding capital expenditures. Through this process, the entire Transmission Business Area project portfolio is reviewed and consolidated each month and any variances are addressed. All projects that indicate they may be outside of allowed variances are re-evaluated and assessed internally by the Transmission organization, and may be escalated for higher-level corporate review. For larger projects (*i.e.*, those greater than or equal to $10 million), we adhere to corporate governance to seek "re-approval" of projects outside the allowed variances.

Transmission also compares year-to-date actual performance with year-to-date and year-end forecasts. Transmission identifies deviations and recommendations to make sure financial targets are reviewed and approved. The Transmission Business Area is expected to manage its capital budget once that budget has been developed, vetted, and approved.

Q. HOW IS THE COMMISSION INFORMED OF THE COMPANY'S TRANSMISSION PROJECTS?

A. On an annual basis, Public Service provides the Commission with its Rule 3206 Report, which identifies new construction or expansion of transmission facilities planned for the upcoming three calendar years. The report consists of five major sections: (1) new projects that may require a CPCN; (2) projects for which the Company requests a determination that no CPCN is necessary because the project is ordinary course of business; (3) status of projects previously reported; (4) projects generally considered conceptual at the time of filing which are being provided for informational purposes only; and (5) projects associated with the Colorado Energy Plan Portfolio ("CEPP") for which Public Service will file additional CPCN(s). The intent of Rule 3206 is to have utilities apprise the Commission of planned transmission projects and to allow the Commission to verify or determine which projects require or do not require a CPCN. Public Service submits its Rule 3206 Report annually by April 30, and filed its most recent Rule 3206 Report in Proceeding No. 22M-0005E.[1]

Additionally, Rules 3625, 3626, and 3627 set forth requirements for transmission planning applicable to Commission-regulated utilities. These rules require these utilities to establish a process to coordinate the planning of additional electric transmission in Colorado in a comprehensive and transparent manner.

[1] The Commission noticed the Company's Rule 3206 Report filing on May 13, 2022 (mailed date) by Decision No. C22-0295-I, instructing interested parties to file comments on or before June 13, 2022. The Commission issued its Decision, Decision No. C22-0438, on the Company's Rule 3206 Report on August 2, 2022 (mailed date).

The process is to be conducted on a statewide basis and takes into account input received from interested stakeholders. The Commission's rules require periodic reporting to the Commission. Public Service and the other Commission-regulated utilities jointly submit a Rule 3627 10-Year Transmission Plan bi-annually on February 1 in even years, the most recent of which was filed in Proceeding No. 22M-0016E. These Rule 3267 plans are the result of a cooperative effort between Black Hills Colorado Electric, LLC d/b/a Black Hills Energy, Tri-State, and Public Service.

The Commission is also informed of our transmission projects through the Company's annual Transmission Cost Adjustment ("TCA") filing in November, as well as individual CPCN filings made with the Commission as appropriate.

Q. WHAT IS THE PURPOSE OF THE TCA?

A. The TCA is the mechanism through which the Company recovers its transmission capital expenses. Each year, the Company requests recovery of its transmission capital expenses through its TCA filings, where the Commission has the opportunity to review the Company's forecasted transmission capital expenses. The Company's TCA was approved by Decision No. C07-1085 in Proceeding No. 07A-339E, and the TCA tariff is set forth on Sheet Nos. 142-142C, COLO. PUC No. 8 - Electric. Among other things, the TCA tariff provides that "[w]henever the Company implements changes in base rates as the result of a final order in an electric Phase I rate case, it shall simultaneously adjust the TCA to remove all costs that have been included in base rates." Company witness Mr. Freitas discusses the Company's proposed TCA roll-in to base rates in his Direct Testimony.

IV. TRANSMISSION 2022-2023 CAPITAL ADDITIONS

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

A. The purpose of this section of my Direct Testimony is to support Transmission's capital additions from January 1, 2022 through December 31, 2023.[2] I begin with an overview and then provide details about specific capital projects, organized by Transmission's six capital budget categories: (1) Asset Renewal; (2) Regional Expansion; (3) Reliability Requirements; (4) Interconnection; (5) Physical Security and Resiliency; and (6) Communication Infrastructure.

A. Overview of 2022-2023 Capital Additions

Q. PLEASE SUMMARIZE TRANSMISSION'S 2022-2023 CAPITAL ADDITIONS.

A. Transmission's capital additions for 2022-2023 are summarized in Table GYF-D-1. I have also provided 2021 actual capital additions in this table for reference.

[2] Transmission's WMP capital additions are discussed by Company witness Mr. Farruggia.

Table GYF-D-1
Transmission Capital Additions
Public Service Electric (Dollars in Millions)

Budget Category	**2021** (Actual)	**2022** 1/1 – 6/30 (Actual)	7/1 – 12/31 (Forecast)	Total	**2023** (Forecast)
Asset Renewal	$55.0	$26.7	$45.4	$72.1	$192.3
Regional Expansion	$5.1	$0.6	$98.7	$99.3	$26.5
Reliability Requirements	$26.7	$26.1	$28.4	$54.6	$48.5
Interconnection	$7.6	$41.2	$7.6	$48.8	$9.9
Physical Security and Resiliency	$6.9	$2.0	$16.6	$18.6	$9.5
Communication Infrastructure	$0.9	$0.0	$6.2	$6.3	$20.2
Total**	$102.3	$96.7	$202.9	$299.6	$306.9

* This table does not include Transmission's WMP capital additions which are discussed separately by Company witness Mr. Farruggia.
** There may be differences between the sum of the individual category amounts and Total amounts due to rounding.

More detail on the Transmission's capital additions for January 1, 2022 to December 31, 2023 are included in Attachment GYF-1 (2021 - 2023 capital additions).

Q. PLEASE DESCRIBE THE DRIVERS OF TRANSMISSION'S CAPITAL INVESTMENTS IN 2022 AND 2023.

A. Transmission makes capital investments to maintain and improve the reliability of the transmission system. An important part of maintaining the reliability of the transmission system is replacing or refurbishing facilities that are in poor condition or that have reached the end of their useful 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. The assets that the Company plans to replace in 2022 and 2023 as part of our Asset Renewal programs have reached or exceeded their useful life. The physical deteriorations and declining electrical performances of these assets increase the likelihood of critical failures and sustained outages. Given the age, condition, and electrical performance of many of our transmission facilities, Public Service is making increasing investments in 2022 and 2023 to replace these facilities to 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 new generation sources. The Regional Expansion projects that the Company will be investing in during 2022 and 2023 include the Greenwood to Denver Terminal 230 kV Transmission Project and Uprate Projects ("GDT Project") and the Canal Crossing – Goose Creek 345 kV transmission line project (part of the Company's Power Pathway Project).

In 2022 and 2023, 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 NERC reliability standards.

Below I discuss the major Transmission projects Public Service has placed into service or will place into service in 2022 and 2023. Namely, below I identify and discuss the projects that comprise approximately 80 percent (or more) of Transmission's total capital additions for each of the capital budget categories described above in 2022 and 2023.

B. <u>Asset Renewal</u>

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF TRANSMISSION CAPITAL ADDITIONS RELATED TO ASSET RENEWAL IN 2022 AND 2023.

A. In 2022-2023, Transmission will be making increasing investments in Asset Renewal projects to address the condition of our transmission facilities. These investments include several major rebuild projects to replace aging transmission line facilities that are in poor condition. The total capital additions for Asset Renewal programs and projects for January 1, 2022 to December 31, 2023 total $264.4 million.

Q. PLEASE PROVIDE AN OVERVIEW OF TRANSMISSION'S ASSET RENEWAL PROGRAMS.

A. Transmission's Asset Renewal programs are used to fund yearly replacement and refurbishment of key transmission facilities. Many of Transmission's Asset Renewal programs are focused on replacing equipment or facilities that have reached the end of their service life. These programs are referred to as End-of-Life or ELR programs. Transmission also has Asset Renewal programs that are focused on replacing assets that unexpectedly fail due to storms or other causes. The key Asset Renewal programs that have capital additions in 2022 and 2023 are:

- *Major Line Rebuild program:* This program is focused on rebuilding large segments of transmission line that have a concentrated number of defects that contribute to poor line performance. These projects are typically required either because the existing line circuits are at risk for increased outage frequency or because the number of structural defects on the circuit makes it unreasonable to refurbish only the defective portions. A rebuild project requires complete wreck out/removal of the physical line assets, which are then replaced with new line assets (e.g., structures, conductor, and switches) either within the existing right-of-way or with minor, targeted right-of-way expansion to accommodate outage constraints and safe construction practices. The Company plans to place in service $26.9 million in capital additions in 2022 and 2023 as part of the Major Line Rebuild program.

- *Storms and Emergency ("S&E") Substation program*: This program replaces equipment that has failed due to a storm event or that is identified through a condition assessment as having a high probability of failure. Equipment that is replaced as part of this program includes the replacement of small substation assets such as reactors, relays, switches, and DC battery systems. An example of a project that will be completed as part of this program in 2022 and 2023 is the Ridge-9684 Replace Capacitor Bank project where the 115 kV reactor needs to be replaced at the Ridge Substation due to the condition of this asset. The Company plans to place in service $17.2 million in capital additions in the S&E Substation program in 2022 and 2023.

- *Major Line Refurbishment program*: The Major Line Refurbishment program is a program to replace specific transmission line components, such as defective cross-arms, poles, and other structural components. This program differs from the Major Line Rebuild program in that the Major Line Rebuild program involves the complete removal and replacement of existing assets whereas the Major Line Refurbishment program addresses specific defects on an entire line segment (breaker to breaker), replacing all like property units on the line segment. By refurbishing specific components of a line segment, rather than rebuilding an entire line, the Company is able to increase circuit reliability and performance and extend the residual circuit life by between 10 to 20 years at a lower cost than a full line replacement. The Company plans to place in service $13.3 million in capital additions as part of the Major Line Refurbishment program in 2022 and 2023.

- *Storms and Emergency ("S&E") Line program:* S&E Line program includes projects associated with necessary replacement work in response to weather events, accidents, and other unscheduled maintenance work that if not completed puts the system at risk of failure. The work typically includes the replacement of cross-arms, poles, conductor, insulators, and other line appurtenances. The Company plans to place in service $9.8 million in capital additions as part of the S&E Line program in 2022 and 2023.

- *End-of-Life Replacement ("ELR") Breaker program:* Substation circuit breakers are devices used to protect the electrical system by interrupting short-circuit current that can be harmful to the station. These devices are also used to open and close circuits. This program targets substation circuit breakers for replacement that have been identified due to poor performance or lack of available replacement parts for repair. The Company plans to place in service $24.1 million in capital additions as part of the ELR Breaker program in 2022 and 2023.

- *ELR Relay program:* Protective relays monitor power system quantities, typically voltages and currents, and open and close circuits to remove short circuits from the power system. The ELR Relay program targets relays for replacement that exhibit poor performance and/or lack available replacement parts. The Company plans to place in service $21.2 million in capital additions as part of the ELR Relay program in 2022 and 2023.

- *ELR Transformer program:* Substation transformers step voltage up or down. The ELR Transformer program targets substation transformers for replacement that have been identified due to poor performance or lack of available replacement parts for repair. The Company plans to place in service $6.1 million in capital additions as part of the ELR Transformer program in 2022 and 2023.

Q. PLEASE DESCRIBE THE DISCRETE ASSET RENEWAL PROJECTS THAT THE COMPANY PLANS TO PLACE IN SERVICE IN 2022 AND 2023.

A. In addition to the Asset Renewal programs I discussed, Transmission also plans to complete several discrete Asset Renewal projects in 2022 and 2023. These discrete Asset Renewal projects are needed to replace transmission facilities that are near the end of their useful life. The major discrete Asset Renewal projects that the Company plans to complete in 2022 and 2023 include:

- *9811 Major Line Rebuild:* This project involves rebuilding 73 miles of 115 kV transmission line on Circuit 9811 from the Poncha Junction Substation to the Sargent Substation then on to San Luis Valley Substation with new steel structures, conductor, and optical ground wire (OPGW). The existing circuit primarily consists of wood structures installed around 1956 that has more than 1,400 defective components. Therefore, this project aims to improve system reliability by completely replacing this deteriorated circuit. This is a multi-year project with construction spanning from 2022 through 2024. Capital additions in 2022 and 2023 for this project are forecasted to be $42.8 million.

- *9256 Major Line Rebuild:* This project involves rebuilding 11 miles of 115 kV transmission line on Circuit 9256 from the Hopkins Substation to the Basalt Substation with new steel structures, conductor, and OPGW. The existing circuit primarily consists of steel structures installed around 1908 that has more than 80 defective components. This project aims to improve system reliability by completely replacing this deteriorated circuit. Capital additions in 2022 and 2023 for this project are forecasted to be $16.9 million.

- *9254 Major Line Rebuild:* This project involves rebuilding 13 miles of 115 kV transmission line on Circuit 9254 from the Leadville Substation to the Climax Substation with new steel structures, conductor, and OPGW. The existing circuit primarily consists of wood structures installed around 1930 and has more than 110 defective components. This project aims to improve system reliability by completely replacing this deteriorated circuit. Capital additions in 2022 and 2023 for this project are forecasted to be $16.8 million.

- *9255 Major Line Rebuild:* This project involves rebuilding 20 miles of 115 kV transmission line on Circuit 9255 from Malta to Otero Tap Substations in San Luis Valley with new steel structures, conductor, and OPGW. The existing circuit primarily consists of wood structures installed around 1950 and has more than 360 defective components. This project aims to improve system reliability by completely replacing this deteriorated circuit. Capital additions in 2022 and 2023 for this project are forecasted to be $16.0 million.

C. <u>Regional Expansion</u>

Q. PLEASE DISCUSS THE KEY REGIONAL EXPANSION PROJECTS IN 2022 AND 2023.

A. There are three key Regional Expansion projects that have capital additions in 2022-2023: (1) Voltage Control Facilities Project; (2) the Greenwood to Denver Terminal 230 kV Transmission Project and Uprate Projects ("GDT Project"); and (3) Canal Crossing – Goose Creek 345 kV Transmission Project (part of Colorado Power Pathway).

Q. PLEASE DESCRIBE THE VOLTAGE CONTROL FACILITIES PROJECT.

A. The Voltage Control Facilities Project is needed to implement the CEPP by accommodating the early retirement of Comanche 1 and 2 and safely and reliably integrating the wind and solar generating facilities. The Voltage Control Facilities Project includes installing voltage support devices, capacitors, and reactors at several different substations.

The Company applied for a CPCN for the Voltage Control Facilities Project in Proceeding No. 19A-0728E. This CPCN proceeding was combined with the Company's CPCN proceeding for its GDT Project. The Commission granted CPCNs for both projects in September 2020 in Decision No. C20-0648.

In 2022 and 2023, the Company will continue to develop the STATCOM flicker control project located at the CF&I Furnace Substation if it is needed. The Company is currently studying the system to determine if this flicker mitigation project is still warranted. The Voltage Control Facilities project is forecasted to have $0.4 million in capital additions in 2022 and 2023 related to the final integration of the other voltage control projects located at the Missile Site, Daniels Park, and Pronghorn substations.

Q. PLEASE DESCRIBE THE GDT PROJECT.

A. The GDT Project is needed to implement the CEPP approved by the Commission in Decision No. C18-0761 in Proceeding No. 16A-0396E (i.e., the Company's 2016 Electric Resource Plan ("ERP") proceeding). The GDT Project involves: (1) installing approximately 15 miles of new 230 kV transmission facilities located in existing rights-of-way originating at the existing Greenwood Substation, located in the southeastern Denver Metro area, and terminating at the Denver Terminal Substation located on the west side of the City of Denver's city center; and (2) modifications to the existing Greenwood, Arapahoe, and Denver Terminal substations to accommodate the new 230 kV circuit, including an expansion of the Denver Terminal Substation.

In February 2020, the Company applied for a CPCN for the GDT Project in Proceeding No. 20A-0063E. This CPCN proceeding was combined with the Company's CPCN proceeding for its Voltage Control Facilities Project. The Commission granted CPCNs for both projects in September 2020 in Decision No. C20-0648.

Construction of the transmission line uprate projects were completed in 2020 and modifications of facilities for the transmission line were completed in June 2021. The remaining 230 kV transmission line construction and substation installations and modifications are scheduled to be completed in December 2022. The GDT Project is forecasted to have $73.6 million in capital additions in 2022.

Q. DID THE COMMISSION'S CPCN DECISION INCLUDE ANY SPECIAL CONDITIONS RELATED TO THE VOLTAGE CONTROL FACILITIES PROJECT AND THE GDT PROJECT?

A. Yes. The Commission's decision approving CPCNs for the Voltage Control Facilities Project and the GDT Project, requires that "Public Service in its next base rate case filing following the date that all facilities associated with the Voltage Control and GDT CPCNs are in service, to specifically identify the actual costs for the Voltage Control and GDT projects, individually and in total, in at least as much detail as provided in this proceeding."[3] While not all of the facilities associated with the Voltage Control Facilities and GDT projects will be in service prior to the filing of this rate case, the Company is requesting recovery of the costs of these projects in this rate case. As such, the Company is providing the project costs for these two projects at the same level of detail as was presented in the CPCN proceedings. Attachment GYF-7 provides the detailed project costs for the Voltage Control Facilities Project and Attachment GYF-6 provides the detailed project costs for the GDT Project. I note that since the costs in the CPCN proceeding were provided in capital expenditures, the costs presented in Attachment GYF-6 and GYF-7 are also in capital expenditures.

Q. HOW DOES THE CURRENT COST ESTIMATE FOR THE VOLTAGE CONTROL FACILITIES PROJECT COMPARE TO THE COST ESTIMATE PROVIDED IN THE CPCN PROCEEDING?

A. The current forecasted Estimated at Completion ("EAC") cost for the Voltage Control Facilities Project is $79.9 million, which is $13.7 million lower than the $93.6 million estimate provided in the Voltage Control Facilities CPCN proceeding.

Q. HOW DOES THE CURRENT COST ESTIMATE FOR THE GDT PROJECT COMPARE TO THE COST ESTIMATE PROVIDED IN THE CPCN PROCEEDING?

A. The current forecasted EAC cost for the GDT Project is $99.5 million, or $47.6 million higher than the $51.9 million estimate provided in the CPCN proceeding.

[3] Decision No. C20-0648 at 31.

The Company discussed the reasons for this cost increase in its August 1, 2022 Semi-Annual Progress Report #4 to the Commission. As discussed in this report, the Company explained that the additional costs are largely driven by increased engineering and construction costs associated with construction of a portion of the project that crosses and/or parallels BNSF Railway railroad infrastructure. In particular, the Company had to modify its construction methods, design, and scope for the portion of this portion of the project to meet BNSF's federally mandated safety and security requirements and design specifications. The costs of the GDT Project also increased due to the need for an expanded scope of work at the Denver Terminal Substation and Arapahoe Substation due to unforeseen challenges with locating underground obstructions. Additional construction work was required to properly locate underground facilities in these existing substations, which resulted in the need to redesign and engineer the necessary substation modifications. The GDT Project has also experienced general cost increases due to increases in material commodity prices, transportation and fuel costs, and labor costs. With regard to material costs, the Company has experienced increased costs for transformer steel, copper, and oil and increased steel costs for transmission line structures. During construction of the project, the Company has also experienced increased transportation and fuel costs as well as labor cost increases due to a shortage of trained workers.

Q. PLEASE DESCRIBE THE CANAL CROSSING – GOOSE CREEK 345 KV TRANSMISSION LINE PROJECT.

A. The Canal Crossing – Goose Creek 345 kV transmission line project is part of Public Service's Power Pathway Project. The Pathway Project is a series of 345 kV transmission lines totaling approximately 560 miles that will connect the Front Range to areas rich in solar and wind potential in northeastern, eastern, and southeastern Colorado. Public Service applied for a CPCN for the Power Pathway Project in March 2021 and the Commission granted the requested CPCN in June 2022 (mailed date) in Decision No. C22-0270.

The Canal Crossing – Goose Creek 345 kV transmission line project involves building a new 345 kV breaker and a half station configuration at Canal Crossing Switching Station plus the 345 kV breaker and a half station configuration at Goose Creek Switching Station and then connecting them by constructing 146 miles of double circuit 345 kV transmission line. In 2022 and 2023, the Company will be acquiring right-of-way, acquiring land, and performing detailed design, ordering materials, and beginning construction of this project. The Company plans to place in service $23.0 million in capital additions for right-of-way and land acquisition on the Canal Crossing – Goose Creek 345 kV transmission line project in 2022 and 2023.

D. Reliability Requirements

Q. WHAT ARE THE DRIVERS OF THE COMPANY'S INVESTMENTS IN RELIABILTY REQUIREMENT PROJECTS?

A. NERC develops and enforces reliability standards on all transmission owners, operators, and users. The Company performs transmission planning studies to identify necessary upgrades to the system to ensure compliance with NERC reliability standards. Through these studies, transmission planners evaluate different alternatives to meet the identified electrical needs of the system and select the best option to meet the identified need. Total capital additions for Reliability Requirements projects in 2022 and 2023 total $103.1 million.

Q. WHAT ARE THE KEY RELIABILITY REQUIREMENTS PROJECTS IN 2022 AND 2023?

A. The key Reliability Requirement projects in 2022 and 2023 include:

- *Greeley Area Upgrades North project:* The Weld County and Greeley area have been experiencing various system reliability issues including system outages and increasing system component failures. This project involves replacing the 44 kV system with a modern 115 kV and 230 kV infrastructure. Substation scope includes installing a 230/115/44/13 kV Husky transmission Substation, a 115/13 kV Collins Street distribution Substation, expanding the Cloverly Switchyard to a 115/13 kV distribution Substation with ring-bus, and add a 230 kV Terminal at WAPA's Ault Substation. This project also includes installing 21.5 miles of new transmission line including 4.8 miles of new single circuit 230 kV line from WAPA's Ault to Husky Substation, 14.7 miles of new single circuit 115 kV line from Husky to Cloverly Substation, 2.0 miles of single circuit 44 kV line from Husky to Continental Substation, plus removal of the 44 kV transmission and distribution system north of Greeley. Capital additions in 2022 and 2023 are forecasted to be $28.2 million.

- *Pawnee – Daniels Park Reconductor project:* This is a multi-year project that involves rebuilding/reconductoring of approximately 66 miles of transmission line on Circuit 5457 (Pawnee-Missile Site) and Circuit 5113

(Missile Site-Daniels Park), which are single circuit 230 kV lines. The final phase of this project (Phase 4) that will be completed in 2022 is to reconductor the 12.5 miles of pipet conductor with grosbeak conductor from Missile Site to Byers. Capital additions in 2022 and 2023 for this project are forecasted to be $13.8 million.

- *DCP Timnath project:* This project is needed to provide additional capacity to serve new load growth in this fast-growing area of northern Colorado and to provide back-up service to the Cobb Lake and Windsor substations. The Timnath project is a joint project between Transmission and Distribution. The Transmission portion of the project includes construction of a three-mile long double-circuit 230 kV transmission line to connect the Company's new Avery Substation in the Town of Windsor to the existing Ault – Timberline 230 kV transmission line. The Transmission capital additions in 2022 and 2023 for this project are forecasted to be $13.5 million. Company witness Mr. David C. Mino discusses the Distribution portion of this project.

- *DCP High Point project:* This project is needed to accommodate several large residential and commercial developments being planned between Pena Boulevard and Powhaton Road in the City of Aurora, south of Denver International Airport. The DCP High Point project is a joint project between Transmission and Distribution. The project includes construction of a new 230/13.8 kV, 50 MVA High Point Substation, distribution feeders, and construction of approximately 3.5 miles of new 230 kV double-circuit transmission line that will tap into the Company's existing 5277 Spruce-Green Valley 230 kV transmission line. The Company filed a CPCN application for the High Point Project on March 2, 2020 in Proceeding No. 20A-0082E (the "High Point CPCN Proceeding") and the CPCN was granted on October 12, 2020 by Decision No. R20-0725 (exceptions denied in Decision No. C20-0886). The Transmission portion of the High Point project has $12.9 million in forecasted plant additions in 2022 and 2023. Company witness Mr. Mino also discusses the Distribution portion of this project in his Direct Testimony.

- *Spill Prevention Control and Countermeasure (SPCC) Improvements:* This program updates secondary containment at existing Public Service substations to comply with federal environmental law and Xcel environmental policy requirements. Secondary containment is a control measure placed or built around a transformer to prevent its oil from flowing into the drainage system during a spill or discharge. Capital additions in 2022 and 2023 for this program are forecasted to be $10.7 million.

Q. AS PART OF THE HIGH POINT CPCN PROCEEDING, DID THE COMMISSION REQUEST THAT THE COMPANY PROVIDE SPECIFIC INFORMATION TO SUPPORT COST RECOVERY FOR THIS PROJECT?

A. Yes, the Commission's CPCN Decision in the High Point CPCN Proceeding ("High Point CPCN Decision") directed that in the next base rate case filing following the date that all facilities associated with the High Point project are in service that Public Service "specifically identify the actual costs for the Project, individually and in total, in at least as much detail as provided in this proceeding."[4] While all of the components of the DCP High Point project will not be placed in service until May 2023, the Company is requesting recovery of the costs for the High Point project in this proceeding. Attachment GYF-5C provides a detailed cost estimate for the High Point project and compares the EAC cost with the costs presented in the High Point CPCN Proceeding. I note that since the costs in the High Point CPCN Proceeding were provided in capital expenditures, the costs in Attachment GYC-5C are also presented in capital expenditures rather than capital additions.

Q. HOW DOES THE CURRENT COST ESTIMATE FOR THE DCP HIGH POINT PROJECT COMPARE TO THE COST ESTIMATE PROVIDED IN THE HIGH POINT CPCN PROCEEDING?

A. In the High Point CPCN Proceeding, Public Service provided a cost estimate of $10.7 million (capital expenditures) for the Transmission portion of the DCP High Point project. The Company's current cost estimate for the Transmission portion

[4] Proceeding No. 20A-0082E, Decision No. R20-0725, ¶ 71 (mailed Oct. 12, 2020).

of the DCP High Point Project is $15.1 million (capital expenditures). In the High Point CPCN Proceeding, Public Service also provided a cost estimate of $17.6 million (capital expenditures) for the Distribution portion of the DCP High Point project. The Company's current cost estimate for the Distribution portion of the DCP High Point Project is $22.5 million (capital expenditures).

Q. PLEASE EXPLAIN WHY THE CURRENT FORECASTED CAPITAL EXPENDITURES FOR THE DCP HIGH POINT PROJECT ARE HIGHER THAN THE AMOUNT ESTIMATED IN THE HIGH POINT CPCN PROCEEDING.

A. There are several reasons why the current costs are higher: (1) higher steel commodity prices; (2) general supply chain and inflationary pressures; and (3) substantive scope/design changes that I will address later in my testimony. Steel prices increased rapidly following the onset of the COVID-19 pandemic and have generally remained well above pre-pandemic levels (which were the basis of the cost estimates in the High Point CPCN Proceeding, with a decision reached in October 2020). As steel is needed for the infrastructure at the High Point Substation, the increase in steel prices have resulted in higher material risk reserves and escalation of the expected cost of the project. Second, like many aspects of the Company's business (and the economy overall) as described by Company witness Mr. Sangram Bhosale, supply chain challenges and inflation throughout the economy have increased material costs from what was assumed in the High Point CPCN Proceeding. For example, the anticipated capital additions for the substation transformer and switchgear is approximately $12.3 million in 2023. In 2021, the Company's budget estimates for these pieces of equipment was $10.1 million. Inflationary pressures have been driving up the costs for all facets of the project.

Q. PLEASE EXPLAIN HOW SCOPE/DESIGN CHANGES FOR THE DCP HIGH POINT PROJECT HAVE IMPACTED THE TRANSMISSION COSTS FOR THIS RPOJECT?

A. The final permitted location for the substation shifted due to landowner opposition and required two additional transmission lines to connect into the existing system. The proximity of these lines to the Denver International Airport necessitated use of special reduced-height structures. The additional lines and the associated materials, engineering, construction and overhead costs contributed a $2.5 million increase to the Transmission costs for the project. Furthermore, the additional line length carried with it an increase in land and right-of-way costs of $1.5 million.

Q. PLEASE EXPLAIN WHY THE CURRENT FORECASTED DISTRIBUTION CAPITAL EXPENDITURES FOR THE DCP HIGH POINT PROJECT ARE HIGHER THAN THE COSTS ESTIMATED IN THE CPCN PROCEEDING.

A. Distribution cost increases were also driven by two main factors. First, the permitted substation location added site specific requirements of a longer access drive at a cost increase of $0.8 million, additional grading and detention pond that increased the cost of the project by $2.0 million, and added screening requirements adding $0.6 million more in wall cost. Second, post-pandemic inflationary cost pressures on construction labor, materials, commodities, and associated overheads added another $1.5 million to the substation costs.

E. Interconnection

Q. WHAT ARE THE DRIVERS OF TRANSMISSION'S INTERCONNECTION INVESTMENTS?

A. Transmission is required to make necessary upgrades to accommodate interconnection requests. There are three general types of Interconnection projects that drive our interconnection investments: generation interconnections, transmission interconnections, and load interconnections. Generation interconnections are where a new generator requests to interconnect to our transmission system. Transmission interconnections are where one utility requests to interconnect a transmission line to our transmission system. Load interconnections are where a new substation serving electric load is needed and requests to interconnect to our transmission system or an existing load serving substation is being modified.

Q. WHAT ARE THE KEY INTERCONNECTION PROJECTS IN 2022 AND 2023?

A. The key Interconnection projects in 2022 and 2023 include:

- *GI-2018-24 Neptune:* The Tundra Switching Station is located 20 miles from the existing Comanche Substation in Pueblo County and was constructed to accommodate the new "Neptune" 250 MW Hybrid Generating Facility (250 MW solar plus 125 MW Battery Energy Storage) approved as part of the CEPP. The initial design of the Tundra Substation includes tapping the Comanche – Daniels Park 345 kV line. The Tundra Switching Station consists of a three-breaker ring configuration. This project is budgeted to have $22.1 million in capital additions in 2022 and 2023.

- *GI-2018-25 Thunderwolf:* The Mirasol Switching Station is located 12 miles east of the existing Comanche Substation in Pueblo County was constructed to accommodate the new "Thunderwolf" 200 MW Hybrid Generating Facility (200 MW solar plus 100 MW Battery Energy Storage) approved as part of the CEPP. The initial design of the Mirasol

Substation includes tapping the Comanche – Midway 230 kV line. This project is budgeted to have $19.9 million in capital additions in 2022 and 2023.

- *GI-2015-16 Arriba:* The scope of this project is to satisfy generation interconnection request "GI-2015-16 Arriba" to connect a new 200 MW wind generation facility at the Shortgrass Switching Station by installing a line termination and a 30 MVAR reactor at the existing Shortgrass Switching Station. This project is budgeted to have $10.4 million in capital additions in 2022 and 2023.

F. <u>Physical Security and Resiliency</u>

Q. PLEASE DISCUSS THE PRIMARY DRIVERS OF TRANSMISSION CAPITAL ADDITIONS RELATED TO PHYSICAL SECURITY AND RESILIENCY IN 2022 AND 2023.

A. Transmission is focused on maintaining the physical security of our assets. High voltage transformers make up less than three percent of transformers in U.S. electric power substations, but they carry 60 to 70 percent of the nation's electricity. Because they serve as vital nodes and carry bulk volumes of electricity, these transformers are critical elements of the nation's electric power grid. They are also the most vulnerable to intentional damage from malicious acts. In April 2013, a substation in California was subject to a coordinated military-type sniper attack that disabled high voltage transformers and rendered this substation useless. Federal regulatory agencies have responded to these growing threats by adopting physical security standards for transmission facilities. On March 7, 2014, FERC issued an Order on Reliability Standards for Physical Security Measures, resulting in NERC standard CIP-014 addressing risks due to physical security threats and vulnerabilities. To address these threats and meet these new NERC standards, Public Service is making necessary investments to make our grid more resilient so that the Company can respond quickly to physical security threats. Total capital additions for Physical Security and Resiliency projects in 2022 and 2023 are forecasted to be $28.1 million.

Q. WHAT ARE THE KEY PHYSICAL SECURITY AND RESILIENCY PROJECTS THAT TRANSMISSION PLANS TO PLACE SERVICE IN 2022 AND 2023?

A. The majority of the Physical Security and Resiliency projects that are planned to be placed in-service in 2022 and 2023 will be part of the two programs: (1) Operational Technology ("OT") Cyber Security program and (2) Physical Security program.

Q. WHAT IS THE OT CYBER SECURITY PROGRAM?

A. The OT Cyber Security program involves upgrades to the Company's transmission infrastructure to meet NERC CIP-1047 requirements. These upgrades include security monitoring and logging, vulnerability and patch management, and information management/password management and asset management. The Company anticipates placing in service $14.3 million in capital additions as part of this program in 2022 and 2023.

Q. PLEASE DESCRIBE THE PHYSICAL SECURITY PROGRAM.

A. The purpose of this program is to improve the physical security of the Company's substations and to ensure compliance with NERC CIP-014. The Company plans to place in service $13.7 million in capital additions as part of this program in 2022 and 2023. An example of a project that the Company plans to complete during this period involves physical infrastructure upgrades at the Denver Terminal

Substation. These upgrades include upgrading the substation fence, replacing existing lighting, gate replacements, and other security related improvements.

G. Communication Infrastructure

Q. WHAT ARE THE KEY COMMUNICATION INFRASTRUCTURE PROJECTS IN 2022 AND 2023?

A. The Communication Infrastructure projects that the Company plans to in service in 2022 and 2023 will be part of the Communication Network program.

Q. DESCRIBE THE COMMUNICATION NETWORK PROGRAM.

A. The Communication Network program aims to privatize Xcel Energy's communication network infrastructure across the Public Service territory, wherever possible, at all transmission and distribution substations for SCADA, tele-protection, and remote engineering access. Specifically, the program addresses aging analog circuit technology and other technology that is anticipated to become obsolete within five years. The Company will then build secure communication architecture for physically isolated operational technology (OT) and information technology (IT) networks from each other to support islanding of the energy management system (EMS) for further cyber security resilience. The program will enable the Company to reduce dependency on third-party circuit providers, which will improve the Company's troubleshooting response time and reduce circuit down time. The Company has budgeted $25.5 million for the Communication Network program in 2022 and 2023.

Q. PLEASE PROVIDE AN EXAMPLE OF A COMMUNICATION NETWORK PROGRAM PROJECT THAT IS PLANNED TO BE COMPLETED IN 2022 OR 2023.

A. One example is the replacement of the overhead shield wire between the Vasquez and Fort Lupton substations with OPGW. To accommodate this replacement, 14 transmission structures will be replaced plus structure modifications and defect corrections will be completed. In addition, the Company will be working to accommodate fiber connections inside the electrical equipment enclosures at the substations.

V. TRANSMISSION O&M EXPENSES

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

A. The purpose of this section of my Direct Testimony is to support the Company's non-WMP Transmission O&M expenses through June 30, 2022, as adjusted for: (1) items discussed below; and (2) labor and non-labor costs as discussed and quantified by Company witnesses Mr. Michael P. Deselich and Mr. Freitas, as the appropriate level of non-WMP Transmission O&M expense in the Test Year.[5]

Q. FOR BACKGROUND, DOES THE COMPANY RECOVER TRANSMISSION O&M EXPENSES THROUGH THE TCA?

A. No. The TCA is only used for recovery of capital expenses for Transmission projects. Transmission O&M expenses are recovered through base rates.

Q. WHAT ARE THE TYPES OF COSTS THAT THE TRANSMISSION BUSINESS AREA INCURS FOR O&M?

A. I describe above the various work that is performed by the Transmission Business Area. To perform this work, the Transmission Business Area generally incurs O&M expenses each year in the following six categories:

- *Internal Labor:* Costs related to the O&M portion of salaries, straight time labor, overtime, premium time, and employee expenses for internal employees.
- *Contract Labor and Consulting:* Costs related to the use of contract labor and consultants, which allows Public Service to increase and decrease staffing levels as workloads require rather than adding more full-time staff, and to retain the services of experts as needed for specific tasks or project efforts.

[5] Transmission's WMP O&M is discussed by Mr. Farruggia.

- *Fees:* Fees the Company is required to pay include regulatory fees, license fees and permits related to railroads and land, environmental fees, and professional association dues that are necessary for the operation of our business.

- *Materials:* Costs related to consumables, hardware, and refurbished materials used in substation maintenance and repair operations, as well as tools, small equipment, and supporting supplies.

- *Fleet:* Costs for the internal fleet assets as directed to O&M accounts on an hourly basis including cars, trucks, construction equipment, and trailers.

- *Other:* Includes miscellaneous other costs such as use costs, maintenance costs, employee expenses, rents, network communication costs and office supplies.

Q. WHAT WERE TRANSMISSION'S ACTUAL O&M COSTS FOR THE 12-MONTH PERIOD ENDING JUNE 30, 2022?

A. Transmission's actual O&M expenses for the 12-month period ended June 30, 2022 totaled $28.0 million. Table GYF-D-2 below breaks down these actual O&M costs by the cost categories I discussed above. Attachments GYF-2 and GYF-3 provide an accounting of these O&M expenses by Cost Element and FERC account, respectively. I note that the O&M amounts presented in my testimony and attachments include Transmission O&M associated with WMP. Attachment GYF-2 provides a breakout showing the amount of Transmission WMP O&M included in each O&M cost category. Mr. Farruggia provides details regarding the Transmission WMP O&M in his Direct Testimony.

TABLE GYF-D-2:
Transmission Actual O&M Expenses*
Public Service Electric
(Dollars in Millions)

Cost Category	**12 Months Ended June 30, 2022**
Internal Labor	$15.1
Contract Labor and Consulting	$6.2
Fees	$7.0
Materials	$1.2
Fleet	$1.2
Other	($2.8)
Total	**$28.0**
**There may be differences between the sum of the individual category amounts and totals due to rounding. All amounts include WMP O&M.*	

Q. PLEASE COMPARE TRANSMISSION'S O&M COSTS FOR 2021 TO TRANSMISSION'S O&M COSTS FOR THE 12 MONTHS ENDED JUNE 30, 2022.

A. Table GYF-D-3 below compares Transmission's actual O&M costs for the 12 months ended December 31, 2021 to actual O&M costs for the 12 months ended June 30, 2022, by cost category.

TABLE GYF-D-3:
Drivers of Transmission O&M Expenses
Public Service Electric
(Dollars in Millions)

Cost Category	12 Months Ended December 31, 2021	12 Months Ended June 30, 2022	Test Year Adjustments	Transmission Test Year O&M Expenses
Internal Labor	$15.0	$15.1	$(0.2)	$14.9
Contract Labor and Consulting	$6.3	$6.2	$(0.4)	$5.8
Fees	$6.9	$7.0	$(3.2)	$3.7
Materials	$1.3	$1.2		$1.2
Fleet	$1.0	$1.2		$1.2
Other	$(2.6)	$(2.8)	$4.2	$1.4
Total Electric	**$27.9**	**$28.0**	**$0.3**	**$28.3**

**There may be differences between the sum of the individual category amounts and totals due to rounding.*
All amounts include Transmission WMP O&M.

Q. CAN YOU PROVIDE MORE INFORMATION REGARDING THE MAIN DRIVERS OF THE DIFFERENCES SHOWN IN TABLE GYF-D-3?

A. As shown in Table GYF-D-3, the slight increase in O&M expenses from 2021 actuals to actuals for the 12 months ending June 30, 2022 was due to increases in Internal Labor, Fees, and Fleet. The reasons for these increases are as follows:

- *Internal Labor:* Labor was relatively flat with merit increases offset by more labor charged to capital.
- *Fees:* Fees were relatively flat but there was a slight increase due to increased fees for our membership in several regional transmission organizations and fees for access to organization research.
- *Fleet:* Public Service experienced an increase in fleet costs, which was driven by a higher fuel and vehicle maintenance costs in 2022.

Q. PLEASE DESCRIBE THE TEST YEAR ADJUSTMENT THAT IS SHOWN IN THE TABLE ABOVE?

A. The Test Year adjustment that is shown in the table above reflects removal of a one-time net credit for a cancelled project. As this one-time journal entry net credit for this cancelled project will not reoccur, the Company has removed this net credit.

Q. ARE YOU PROPOSING ANY OTHER ADJUSTMENTS TO THE COMPANY'S O&M EXPENSES TO BE REFLECTED IN THE TEST YEAR FOR TRANSMISSION O&M EXPENSES?

A. Yes. In addition to the net credit I discussed, Public Service is also proposing an adjustment for Transmission wheeling services costs, which I discuss in Section VI below.

Q. IS THE COMPANY'S ACTUAL TRANSMISSION O&M EXPENSE FOR THE 12-MONTHS ENDING JUNE 30, 2022, SUBJECT TO ADJUSTMENTS THAT YOU IDENTIFIED, A REASONABLE STARTING BASIS FOR ESTABLISHING TRANSMISSION'S O&M COSTS FOR THE TEST YEAR?

A. Yes. The Company's actual Transmission O&M costs for the 12-months ending June 30, 2022, subject to the Company's adjustments, are a reasonable basis on which to establish Transmission's O&M costs for the Test Year. These O&M expenses are necessary to ensure that the Transmission Business Area is able to deliver safe and reliable electric service to our Colorado customers.

VI. TRANSMISSION WHEELING SERVICES COSTS

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

A. In this section of my Direct Testimony, I describe Public Service's use of third-party wheeling service to transmit power to serve its customers as well as the costs for these services. My Direct Testimony provides support for the adjustments for Transmission Wheeling Services included in the Test Year cost of service sponsored by Mr. Freitas.

Q. ARE WHEELING COSTS PART OF THE TRANSMISSION AREA'S CAPITAL AND O&M BUDGETS?

A. No. These costs are not part of Transmission's capital and O&M budgets I describe above. These costs are incurred by our Commercial Operations area to provide transmission access to serve our retail customers and provide transmission service to import power into the Public Service system.

Q. WHAT IS WHEELING SERVICE?

A. Wheeling is an industry term used to describe the transmission of electricity by an entity that does not own or directly use the electricity that it is transmitting. When a public utility requires use of the transmission or distribution assets of another system in order to deliver electricity to its electric customers, it is required to pay a wheeling charge. In the context of my Direct Testimony, I use the term wheeling to describe the arrangements that Public Service has entered into with its neighboring utilities to utilize their transmission and/or distribution systems to serve Public Service customers in a cost-effective way.

Q. WHY DO UTILITIES ENGAGE IN TRANSMISSION WHEELING?

A. Because the electric grid is an interconnected network, utilities often find that it is more cost effective to purchase transmission service from others to serve their electric customers rather than to construct new facilities. Generally, utilities will utilize wheeling when it is less expensive to purchase wheeling service or where the construction of new facilities is impractical. Utilities may also purchase wheeling service from others to serve customers during outage conditions.

Q. DO UTILITIES PURCHASE TRANSMISSION SERVICE FOR REASONS OTHER THAN SERVING THEIR ELECTRIC CUSTOMERS?

A. Yes. In addition to wheeling energy to serve customers, utilities also purchase wheeling service from others to import generation or to access generation markets. For example, a utility (or developer) may purchase transmission service to import generation from a new wind farm or other generator if the generation resource is not directly interconnected to the utility's core transmission network. A utility may also purchase Point-to-Point ("PTP") transmission service to access market hubs outside of its geographic network so that it may have access to those hubs rather than construct its own native generation. For the purposes of my Direct Testimony, I include these generation-related uses of third-party transmission service when I use the term wheeling.

Q. DOES PUBLIC SERVICE PURCHASE WHEELING SERVICE?

A. Much like other electric utilities, Public Service engages in a number of wheeling transactions to both serve its retail native load, as well as to provide transmission paths into Public Service's network for its generation and market access. In each case, Public Service's use of wheeling service avoids the need to construct duplicative assets that would either be costlier than purchasing wheeling service or are impractical to build or acquire.

Q. WHAT ARE THE WHEELING TRANSACTIONS IN WHICH PUBLIC SERVICE ENGAGES?

A. Attachment GYF-4 identifies Public Service's wheeling transactions for which recovery is being requested in base rates, along with a description of each transaction. As reflected in Attachment GYF-4, the Company is seeking to recover $21 million in wheeling expense.

Q. HAVE WHEELING COSTS INCREASED SINCE THE COMPANY'S 2021 ELECTRIC PHASE I RATE CASE?

A. Yes. Public Service's July 1, 2021 to June 30, 2022 wheeling costs, not including adjustments, were approximately $1.2 million higher than the wheeling costs included in the 2021 Electric Phase I proceeding that used calendar year 2020 level of O&M expense.

Q. WHAT DROVE THIS INCREASE IN COSTS FROM 2020 TO THE JULY 1, 2021 TO JUNE 30, 2022 PERIOD?

A. Changes in wheeling costs were primarily driven by increased costs of the Four Corners-Craig path on Public Service, offset by cost reductions on other wheeling paths.

Q. IS PUBLIC SERVICE UTILIZING JULY 1, 2021 TO JUNE 30, 2022 ACTUAL WHEELING COSTS TO ESTABLISH ITS COST OF SERVICE IN THIS PROCEEDING?

A. Yes, as Mr. Freitas discusses, the Test Year cost of service starts with July 1, 2021 to June 30, 2022 actual O&M costs, but the level of wheeling expenses requested in this rate case has been adjusted for known Test Year adjustments.

Q. DOES ATTACHMENT GYF-4 INCLUDE ALL WHEELING COST ADJUSTMENTS INCLUDED IN THE TEST YEAR?

A. No. In addition to the Test Year adjustments to July 2021 to June 2022 costs I discuss below, Public Service has excluded certain wheeling costs collected through the Electric Commodity Adjustment ("ECA").

Q. WHAT TEST YEAR ADJUSTMENTS TO THE COST OF WHEELING SERVICES IS PUBLIC SERVICE PROPOSING TO MAKE?

A. Public Service has proposed four types of Test Year adjustments: (1) Economic Purchases, (2) Trading Activity, (3) Sales for Resale, and (4) Prior-Year True-Ups.

Economic purchases refers to the procurement of point to point transmission service on other transmission systems due to elevated system conditions; to the extent these costs, when combined with the associated energy purchase, are deemed economic, they are recovered through the ECA. Accordingly, wheeling expenses were adjusted by $1,963,047 to exclude such costs incurred in July 2021 to June 2022.

Trading Activity refers to wheeling charges associated with proprietary and/or off-system trading activity (which are included in the calculation of trading margins and shared with customers through the ECA); therefore, an adjustment of $3,188,981 is necessary to exclude these amounts from wheeling expense.

Sales for resale refers to PTP transmission service that is procured from Tri-State in order to serve a wholesale customer, and approximately $340,224 of associated wheeling expense has been excluded.

Prior-period true-ups includes an adjustment of ($158,070) to exclude accounting adjustments recorded in July 2021 to June 2022 related to the true-up of Public Service's 2021 and 2022 Transmission Integration and Equalization Agreement with Holy Cross Electric Association, Inc.

In total, Public Service proposes a net decrease of $5,334,181 to the Company's July 2021 to June 2022 actual Transmission O&M levels to account for its adjustments, which is reflected in the column "2022 Adjusted" in the table included on page 2 of Attachment GYF-4.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Gilbert Y. Flores

Gilbert Y. Flores is the Manager of Transmission Planning for Public Service Company of Colorado. In this position, Gilbert has responsibility for overseeing the engineering group responsible for planning the transmission system and is also responsible for the development of Transmission budgets, regulatory compliance and portions of the operations and maintenance ("O&M") of Public Service's transmission system. Since 2022, Gilbert has had responsibility for overseeing transmission policy and projects involving participation with other utilities, including conducting strategic analyses for potential transmission projects, evaluating joint agreements, and engaging in stakeholder outreach. Gilbert previously held the role of Regional Transmission Planning Engineer focusing on Colorado and the WestConnect regional group. Gilbert's responsibilities included regional transmission expansion studies across Colorado, evaluation of strategic company initiatives, as well as FERC Order 1000 compliance. As Regional Planner, Gilbert led the Company's latest Rule 3627 10 Year Transmission Plan filed early 2022. Gilbert is currently the Vice-Chair over the WestConnect Planning Management Committee and participates in the WestConnect Planning Subcommittee supporting the two-year WestConnect Planning cycle.

Gilbert joined Xcel Energy in 2012. From 2012 through the end of 2014, Gilbert served as a Distribution Area Engineer focusing on reliability, power quality, and ensured designers and construction crews complied with Company design requirements at the Distribution system level. From 2014 to 2016, Gilbert served as a Substation Standards Engineer. In that role, he developed material standards for various substation equipment as well as developed multiple companywide standards establishing criteria such as substation design clearances. From 2016 to 2017, Gilbert was the Substation System Performance Engineer focusing on the Company's substation asset renewal program. In this role, he initiated and drove to completion many replacement and reconditioning projects in Colorado. In 2017 to 2020, Gilbert served as a Transmission Planning Engineer for Public Service of Colorado. In this role, Gilbert developed WECC model cases and conducted system studies related to load growth and power quality, as well as supported NERC and FERC compliance. Further, Gilbert participated in the Company's internal annual budget as the Transmission Planning representative to ensure project priority and alignment with Company goals.

Gilbert graduated from the University of Houston in 2009 with a Bachelor of Science in Electrical Power Engineering Technology where he was recognized for scholastic achievement in undergraduate studies. In 2018, Gilbert earned a Master of Science in Electrical Engineering with a focus on Power and Energy Systems from Colorado School of Mines. Gilbert has been recognized by EPRI for his work in the development of EPRI's Grid Strength Assessment Tool and awarded a Technology Transfer Award in 2021. Gilbert is a veteran and licensed Professional Engineer in the State of Colorado.

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 TARIFF PROPOSALS EFFECTIVE DECEMBER 31, 2022.	) PROCEEDING NO. 22AL-XXXXE

**AFFIDAVIT OF GILBERT Y. FLORES
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO**

I, Gilbert Y. Flores, 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 22 day of November, 2022.

Gilbert Y. Flores
Manager, Transmission Planning

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

Hannah Ahrendt
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID# 20224028082
MY COMMISSION EXPIRES JULY 5, 2026

Notary Public

My Commission expires July 5, 2026