NOTICE OF CONFIDENTIALITY
A PORTION OF THIS TESTIMONY OR TESTIMONY AND ATTACHMENTS HAS/HAVE BEEN FILED UNDER SEAL.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

* * * * *

IN THE MATTER OF ADVICE NO. 993-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE FEBRUARY 24, 2022	)	**PROCEEDING NO. 22AL-______G**

DIRECT TESTIMONY AND ATTACHMENTS OF ARTHUR P. FREITAS

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

NOTICE OF CONFIDENTIALITY
A PORTION OF THIS TESTIMONY OR TESTIMONY AND ATTACHMENTS HAS/HAVE BEEN FILED UNDER SEAL.

Confidential: Attachment APF-1A_C and Attachment APF-2A_C

January 24, 2022

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

* * * * *

IN THE MATTER OF ADVICE NO. 993-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE FEBRUARY 24, 2022	**) PROCEEDING NO. 22AL-______G**

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

*** * * * ***

IN THE MATTER OF ADVICE NO. 993-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE FEBRUARY 14, 2022	**)**	**PROCEEDING NO. 22AL-______G**

DIRECT TESTIMONY AND ATTACHMENTS OF ARTHUR P. FREITAS

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Arthur P. Freitas. My business address 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 Manager, Revenue Analysis. XES is a wholly owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), and provides an array of support services to Public Service Company of Colorado ("Public Service" or the "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

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

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As Manager, Revenue Analysis, I provide project supervision and technical expertise for jurisdictional cost of service studies, revenue requirement determinations, and related projects for Public Service. I lead a team of analysts who develop revenue requirement models to support the rates charged by Public Service. I direct, review, and analyze the revenue requirements that support the base rates, rate riders, and Federal Energy Regulatory Commission ("FERC") formula rates used by Public Service. 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 present the Public Service Gas Department revenue requirement study, also known as the cost of service study, which supports the requested increase in base rate revenue for the test year the Company is presenting in this proceeding. As discussed by Company witness Mr. Steven P. Berman, the Company is proposing to utilize a test year in this rate case consisting of the calendar year ending December 31, 2022 ("CTY" or "Test Year"). This CTY is based on capital investments and the anticipated capital structure through December 31, 2022, and actual operations and maintenance ("O&M") expense incurred for the 12 months ending June 30, 2021 with forecasted adjustments to present a representative test year for the period rates will be in effect. Mr. Berman also supports proposed capital step increases for 2023 and 2024; however, my testimony is focused on the 2022 CTY.

The overall base rate retail revenue requirement for the CTY is $825,150,684. To arrive at this revenue requirement, I also explain the rationale for, and effect of, many of the adjustments included in the cost of service study. This cost of service study will be utilized by Company witness Mr. Steven W. Wishart to present the Company's class cost of service study, revenue distribution by customer class, and rate design proposals in Phase II of this proceeding.

In addition, as agreed to as part of the settlement reached in a prior Public Service electric Phase I rate case, Proceeding No. 11AL-947E ("2011 Electric Phase I"), I present the gas department's revenue requirements study based on an informational Historical Test Year ("HTY" or "2021 HTY")) with pro forma adjustments. Moreover, I present a variance analysis showing the changes between the HTY and the CTY. The HTY cost of service presented is the 12 months ended June 30, 2021. The HTY is being filed solely for informational, comparative purposes.

Additionally, I present the revenue requirement associated with the former Pipeline System Integrity Adjustment ("PSIA") Rider that will be included in base rates. I also present the level of costs the Company proposes to include in base rates as a baseline for any future deferrals in our tracking mechanisms, including: 1) property taxes; 2) pension expense; 3) damage prevention expenses; and 4) Colorado Public Utilities Commission ("Commission") administration fees.

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

A. Yes, I am sponsoring Attachments APF-1 through APF-15, which were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment APF-1 – Revenue Requirements Study for Public Service Company's Gas Department Based on the 12 Months Ending December 31, 2022;
- Attachment APF-1A_C –Confidential Version of Attachment APF-1A, Adjusted Base Rate Revenue for the CTY;
- Attachment APF-1A – Public Version of Attachment APF-1A, Adjusted Base Rate Revenue for the CTY;
- Attachment APF-2 – Informational Revenue Requirements Study for Public Service Company's Gas Department Based on the Historical Test Year for the 12 Months Ended June 30, 2021;
- Attachment APF-2A_C –Confidential Version of Attachment APF-2A, Adjusted Base Rate Revenue for the 2020 HTY;
- Attachment APF-2A – Public Version of Attachment APF-2A, Adjusted Base Rate Revenue for the 2021 HTY;
- Attachment APF-3 – Comparison of the 2021 HTY versus the cost of service supporting the Company's current base rates approved in Proceeding No. 20AL-0049G;
- Attachment APF-4 – Comparison of the 2021 HTY versus the CTY;
- Attachment APF-5 – Ten Year Detail of Per Book Operating and Maintenance ("O&M") expenses;
- Attachment APF-6 – Ten Year Per Book Gross Plant and Net Plant balances;
- Attachment APF-7 – 2022 detail of Per Book Operating and Maintenance expenses split by Service Company and native Public Service expenses;
- Attachment APF-8 – Audit Trail Map;

- Attachment APF-9 – Regulatory Principles and Adjustments underlying the CTY and the HTY;
- Attachment APF-10 – Lead Lag Study Summary that supports the Cash Working Capital Factors Used in the Cost of Service Study;
- Attachment APF-11 – Lead Lag Study Support, including Revenue Lag detail;
- Attachment APF-12 – Labor Productivity Study;
- Attachment APF-13 – Copies of Recoverable Advertisements for 12 Months Ending June 30, 2021;
- Attachment APF-14 – Pipeline Safety and Integrity Costs in the 2022 CTY for Class Allocation.

II. TEST YEAR REVENUE DEFICIENCY

Q. PLEASE SUMMARIZE THE RESULTS OF THE REVENUE REQUIREMENT STUDY FOR THE CTY.

A. The CTY revenue requirement study shows a total revenue requirement, excluding gas costs collected through the Gas Cost Adjustment ("GCA") and costs collected through the Gas Demand Side Cost Adjustment ("DSMCA"), of $825,150,684. This CTY revenue requirement is based on the proposed return on equity ("ROE") of 10.25 percent for the CTY as recommended by Company witness Ms. Ann E. Bulkley, a long-term cost of debt of 3.73 percent, a short-term cost of debt of 0.79 percent, and a capital structure consisting of 55.66 percent equity, 43.13 percent long-term debt and 1.21 percent short-term debt, as recommended by Company witness Mr. Paul A. Johnson, which results in an overall return on rate base (i.e., the Company's Weighted Average Cost of Capital ("WACC")) of 7.33 percent. When compared to our present revenue of $610,512,984, this revenue requirement results in a base rate revenue increase of $214,637,700.

However, this base rate revenue increase includes transferring the costs that were previously recovered through the PSIA rider to base rates; these transfers are revenue neutral in total to the Company's gas customers. Not including the PSIA rider costs being rolled into base rates, the Company is requesting a net $107,100,123 million base rate increase in this rate case from the level of base rate revenues approved in the Company's last Phase I gas rate case (Proceeding No. 20AL-0049G) ("2020 Gas Combined Rate Case"), as shown in Table APF-D-1 below.

Table APF-D-1

Revenue Requirements per CTY Cost of Service	$ 825,150,684
Less: Revenues Under Present Base Rates	$ 610,512,984
Gross Base Rate Increase Requested	$ 214,637,700
Less: Shift of GRSA-P to Base Rates	$ 107,537,577
Net Increase	$ 107,100,123

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO TRANSFER COSTS PREVIOUSLY RECOVERED THROUGH THE PSIA TO GAS BASE RATES.

A. As previously mentioned, the Company is proposing to transfer the costs that were previously recovered through the PSIA rider to base rates in accordance with the settlement in Proceeding No. 21A-0071G ("PSIA Extension Proceeding"), with the transfer being revenue neutral to Public Service's retail gas jurisdiction. Effective January 1, 2022, and consistent with the PSIA Settlement Agreement in the PSIA Extension Proceeding, the PSIA rider was closed to new projects as of December 31, 2021, and all costs previously eligible for recovery through the PSIA rider as of December 31, 2021 are being recovered through a General Rate Schedule Adjustment ("GRSA-P") specific to the PSIA. These costs comprise the forecasted 2021 PSIA revenue requirement as well as the true up of the 2020 PSIA rider. I discuss the PSIA rider close-out in more detail in Section V(C) of my Direct Testimony.

Moving recovery of these costs (totaling $107,537,577) from the GRSA-P to base rates is revenue neutral, and does not reflect an increase in rates to our customers. I present the specific impact of the transfer of former PSIA costs in

Section V(C) of my Direct Testimony. As reflected in Table APF-D-1 above, excluding the effects of the inclusion of the costs currently in the GRSA-P, the Company is presently seeking a net increase in revenues of $107,100,123.

Q. WHAT IS DRIVING THE NET INCREASE IN BASE RATES THE COMPANY IS REQUESTING IN THIS CASE?

A. The primary driver of the net increase in base rates is capital investment in the gas system since the Company's 2020 Gas Combined Rate Case, which set base rates using a Test Year ending September 2019 (the "September 2019 Test Year"). The September 2019 Test Year included plant and plant-related rate base balances at end of year levels as of September 30, 2019 plus an adjustment for a future portion of the Tungsten to Blackhawk pipeline, and O&M expenses based on actual amounts for the 12 months ended September 2019 plus known and measurable adjustments. The CTY in this case captures plant in service through December 31, 2022, adding to the Company's overall rate base.

The remaining net increase in base rates is due to increases in plant-related costs, such as depreciation expense and property tax. O&M expenses, which are primarily derived from actual O&M data for the 12 months ended June 2021 are slightly increasing as compared to the 2020 Gas Combined Rate Case. Present base rate revenue in the CTY is approximately $19 million higher than the revenue in the 2020 Gas Combined Rate Case, which is offsetting some of the increase arising from the increase in plant related costs. The plant additions, net of retirements since the 2020 Gas Combined Rate Case through the end of the CTY, are provided in Table APF-D-2 below.

Table
APF-D-2

	Oct 2019 - June 2020	July 2020 - June 2021	July 2021 - Dec 2021	2022	Total
Gas Production	(24,728)	42,966	138,719	0	156,956
Gas Products Extraction	431	0	266,872	0	267,303
Gas Storage	498,281	1,996,145	4,741,529	239,464	7,475,420
Gas Transmission	49,385,936	112,142,243	57,398,190	89,227,974	308,154,344
Gas Distribution	201,542,129	257,353,488	245,596,585	292,819,085	997,311,287
Common General and Intangible	61,947,172	63,496,735	177,043,209	182,341,178	484,828,293
Total	313,349,220	435,031,577	485,185,104	564,627,701	1,798,193,603

These plant additions and changes in O&M are described in more detail by the Company's Business Area witnesses: Ms. Joni H. Zich, Ms. Lauren Gilliland, Mr. Michael O. Remington, Mr. Adam R. Dietenberger, Mr. Michael Knoll, and Mr. Richard R. Schrubbe.

Other drivers of the requested net increase in base rates include increased depreciation expense as a result of the increased capital placed into service, as well as updated common plant depreciation rates proposed in the Company's electric rate case in Docket No. 21AL-0317E. Company witness Ms. Laurie J. Wold discusses the change in depreciation rates for common plant.

III. SELECTION OF TEST YEAR AND OTHER DATA PROVIDED

Q. WHAT TEST YEAR HAS THE COMPANY CHOSEN FOR PURPOSES OF ITS REVENUE REQUIREMENTS STUDY IN THIS PROCEEDING?

A. As I previously stated, Public Service is proposing an CTY for this filing. This test year uses the Company's forecasted capital additions for 2022 as of our July 2021 forecast, which serves as the basis for developing the majority of rate base and other plant-related costs. O&M expenses for the CTY are based on the level of O&M expenses in the 2021 HTY. The 2021 HTY starts with the actual O&M expense for the 12 months ended June 30, 2021, and is then adjusted for known and measurable changes in expenses that are expected to occur within 12 months after the end of the 2021 HTY (through June 2022), in compliance with previous Commission findings. This is referred to as the "fully adjusted HTY." The fully adjusted 2021 HTY O&M expenses are then adjusted for forecasted changes in specific areas, as a reasonable proxy for 2022 forecasted O&M. The Company's treatment of O&M for purposes of developing the Test Year is discussed further below. Base revenue is based on our current customer and sales forecast for calendar year 2022.

Q. PLEASE DESCRIBE THE DATA YOU USED TO PREPARE THE CTY IN THIS CASE IN MORE DETAIL.

A. As I noted above, the basis for the 2022 plant in-service balances is our July 2021 capital additions forecast, which includes actual plant balances through June 2021 and the Company's forecasted capital additions through the end of December 2022. This information is used by the capital asset accounting group, as explained by Company witness Ms. Wold, to develop the projected 13-month average plant in-service balances from which the CTY rate base balance was derived.

With regard to O&M expense, we started with the fully adjusted HTY amounts for the 12 months ended June 30, 2021 and then adjusted for forecast changes to specific areas to establish the level of O&M for the CTY. For labor O&M expense in the CTY, we started with the fully adjusted 2021 HTY, which includes labor increases through June 2022 as described above, then added adjustments to account for labor increases expected to occur from June 2022 through December 2022. The specific wage increases are discussed in more detail by Company witness Mr. Michael T. Knoll. In addition, the related payroll taxes and employee incentive amounts were calculated in this manner. For non-labor O&M, again we started with the fully adjusted 2021 HTY, and held the majority of these actual non-labor O&M expense amounts flat for the CTY with few exceptions, as discussed below.

For damage prevention expenses recorded in FERC Account 874, we utilized the Company's latest forecast for the CTY, as discussed by Company witness Ms. Gilliland. For employee benefits expense recorded in FERC Accounts 925 and 926, we utilized the Company's forecast for the CTY, as discussed by Company witness Mr. Schrubbe.

I discuss each of the adjustments to the HTY and the CTY in Section VII of my Direct Testimony. Company witnesses Ms. Gilliland and Mr. Knoll also provide testimony supporting our adjustments to the HTY expenses and additional expense changes anticipated in the CTY.

Q. HAS THE COMPANY PREPARED ADDITIONAL INFORMATION IN THIS CASE TO EXPLAIN AND DEMONSTRATE THE REASONABLENESS OF THE CTY?

A. Yes. Company witness Mr. Berman explains the CTY in his Direct Testimony and discusses the policy basis in support of approving the use of this test year in this proceeding. Company witnesses Ms. Zich, Mr. Remington, and Mr. Dietenberger provide an explanation of the major drivers of the increase in capital additions from the 2020 Gas Combined Rate Case to the CTY. Mr. Remington, Mr. Dietenberger, Mr. Knoll, and Ms. Gilliland address the major drivers of O&M increase from the test year in the 2020 Gas Combined Rate Case to the 2021 HTY.

I have also prepared several attachments that illustrate the reasonableness of the CTY. First, Attachment APF-5 provides a comparison of the 2021 HTY to the September 2019 cost of service which was the basis for the Company's current base rates as approved in the 2020 Gas Combined Rate Case. Second, Attachment APF-6 provides a comparison of the CTY to the 2021 HTY. Third, Attachment APF-7 provides a ten-year O&M expense trend by FERC account. Fourth, Attachment APF-8 provides ten-years of gross plant and net plant balances by function. Attachment APF-9 provides O&M expense detail by FERC account broken out by Public Service native expenses and Service Company expenses. The 2021 HTY cost of service study together with these comparisons and detail schedules should assist the Commission and the intervenors in assessing the reasonableness of the Company's CTY.

Q. WHAT IS THE PURPOSE OF THE INFORMATIONAL HTY THAT THE COMPANY IS PROVIDING IN THIS PROCEEDING?

A. The informational 2021 HTY provides a point of comparison to the Company's proposed CTY. Consistent with prior Commission decisions, the HTY is being filed for information purposes only. In the Settlement Agreement from the 2011 Electric Phase I Rate Case, the Company agreed that if its next Phase I electric rate case were to be based on a future test year ("FTY"), the Company would also file an HTY for informational purposes only. In addition, the HTY is being provided consistent with a Commission decision in Proceeding No. 12AL-1268G ("2012 Gas Phase I"), in which the Commission expressed "concern with the ability of the parties to examine the three FTYs without the ability to examine the growth in revenue requirements in relation to a recent HTY."[1] While the Company is proposing a CTY rather than an FTY in this proceeding, a 2021 HTY is provided for comparison purposes.

Additionally, the 2021 HTY is the starting point for the O&M expenses in the CTY filed in this case. The 2021 HTY cost of service is provided as Attachment APF-2. Below as presented in Table APF-D-3, is a comparison of the retail O&M in the 2021 HTY as compared to the 2022 CTY.

[1] 2012 Gas Phase I, Decision No. C13-0064, ¶¶10-11, 13-15 ("[I]t is important to the Commission and its advisors that an HTY is submitted into the record as a basis for evaluating the FTY sponsored by Public Service. The HTY we are directing Public Service to submit should be the HTY, including all pro forma adjustments that Public Service would have submitted had Public Service sought to use an HTY as the basis for its revenue requirements showing. The additional point of reference provided by an HTY is necessary for the Commission to perform a full investigation of the FTY.").

Table APF-D-3

	2020 HTY	2022 CTY	Difference	Percent Increase
Production	$979,488	$989,307	$9,819	1.0%
Products Extraction	$679,062	$679,062	$0	0.0%
Gas Storage	$1,204,238	$1,217,638	$13,401	1.1%
Other Gas Supply	($880,747)	($870,442)	$10,305	-1.2%
Transmission	$35,947,933	$36,308,539	$360,605	1.0%
Distribution	$107,428,973	$109,413,753	$1,984,780	1.9%
Customer Accounts	$27,680,057	$28,124,923	$444,866	1.6%
Customer Service	$1,543,456	$1,564,171	$20,716	1.3%
Sales	$608,250	$627,046	$18,796	3.1%
A&G	$68,049,669	$67,789,088	($260,581)	-0.4%
Total O&M	$243,240,379	$245,843,087	$2,602,708	1.1%

Attachment APF-4 provides a full comparison of the CTY to the 2021 HTY, and Attachment APF-9 compares the regulatory principles and adjustments underlying the CTY and the 2021 HTY cost of service studies.

Q. PLEASE SUMMARIZE THE RESULTS OF THE 2021 INFORMATIONAL HTY REVENUE REQUIREMENTS STUDY.

A. The 2021 HTY cost of service study shows a total revenue requirement for base rate revenues, excluding gas commodity costs collected through the GCA and costs collected through the DSMCA, of $791,965,811. This is based on the proposed return on equity of 10.75 percent for the HTY, the actual long-term cost of debt of 3.84 percent, the actual short-term cost of debt of 1.66 percent, and the actual capital structure of 55.64 percent equity, 43.84 percent long-term debt, and 0.52 percent short-term debt. When compared to present revenues of $618,521,355, the result is a revenue increase of $173,444,456.

Q. WHAT ARE THE MAJOR DIFFERENCES BETWEEN THE CTY AND THE 2021 HTY COST OF SERVICE STUDIES FILED IN THIS CASE?

A. The major difference between the CTY and the 2021 HTY is that the Company will have additional plant additions in 2022 as compared to the June 2021 year-end level, a higher requested return on equity in the 2021 HTY due to the increased risks and regulatory lag associated with an HTY as described by Company witness Ms. Bulkley, and increases in depreciation expense. Base rate revenue in the CTY also declined relative to the level in the HTY, which contributes to the increase in rates. Attachment APF-4 details the differences between the CTY and the 2021 HTY cost of service.

IV. COST OF SERVICE STUDY DEVELOPMENT

Q. WHAT IS A COST OF SERVICE STUDY?

A. A cost of service study – also referred to as a revenue requirements study or pro forma rate of return study – examines all of the Company's investments, revenues, and expenses associated with providing a utility's service over a specific twelve-month period, or "test year," with the goal of determining the Company's cost of providing service to its customers during the period of time in which new rates will be in effect. The revenue requirements study indicates the overall level of revenues necessary for the Company to have an opportunity to earn its authorized return, which is used in setting the Company's base rates for service. In effect, the revenue requirement establishes a proxy for what the Company's cost of service will be in future periods when the new requested rates will be in effect.

Q. HOW WAS THE COST OF SERVICE STUDY DEVELOPED FOR THIS CASE?

A. As previously discussed, the starting point in developing the CTY cost of service is the 2021 HTY, updated to reflect our capital additions expected to be in-service through December 31, 2022, plus changes to labor and non-labor O&M expense through 2022. In turn, the 2021 HTY cost of service starts with the Company's books and records. The Company uses the FERC System of Accounts[2] as the basis for the book numbers in the cost of service. The per book plant balances presented in the 2021 HTY and the projected plant balances presented in the CTY are in the roll forward schedules supported by Company witness Ms. Wold. The

[2] Code of Federal Regulations Title 18, Part 101, Uniform System of Accounts prescribed for public utilities and licensees subject to the provision of the Federal Power Act.

Company then made regulatory adjustments to the book numbers to develop the cost of service. There are three types of regulatory adjustments that have been made to the HTY cost of service:

1) Accounting adjustments;
2) Commission-ordered adjustments; and
3) *Pro forma* adjustments.

The resulting required revenues computed by the cost of service model are then compared to the revenues the Company expects to collect during the test period, based on current rates applied to projected customers and sales, to determine any deficiency or excess. If present revenues are greater than the required revenues, the result indicates excess revenues and the need for a rate decrease. If present revenues are less than the required revenues, the result indicates a revenue deficiency and the need for a rate increase.

As noted above, the CTY is presented on Attachment APF-1. The HTY cost of service is presented on Attachment APF-2 for informational purposes. For ease of reference, I have included an Index of Schedules at the beginning of these Attachments. The Schedules generally follow this order:

- Schedule 001 – Revenue Requirements
- Schedule 002 – Capital Structure
- Schedules 100 series – Rate Base
- Schedules 200 series – Income Statement
- Schedules 300 series – Jurisdictional and Functional Allocation Factors

Q. IS THERE ANY ADDITIONAL INFORMATION YOU ARE PRESENTING IN THIS RATE CASE TO SUPPORT THE PER BOOK DATA PRESENTED IN THE 2021 HTY?

A. Yes. I am providing additional supporting information in this rate case for the O&M expenses split by Xcel Energy Services, Inc. (the Service Company) and native Public Service expenses, shown in Attachment APF-9. I am also providing in Attachment APF-8, an Excel® spreadsheet (provided as a CD-ROM) that includes the detailed 2021 actual O&M data used as inputs to the HTY. The data presented in Attachment APF-8, referred to as the Audit Trail Map, can be filtered and summarized by FERC account and by Business Area, and equals the per book O&M expenses presented in the 2021 HTY revenue requirement study.

Q. PLEASE DESCRIBE WHAT IS MEANT BY "ACCOUNTING ADJUSTMENTS."

A. Accounting adjustments are made either to eliminate certain accounts or expenses that should not be included in the base rate calculation or to add accounts that should be included in the calculation. For example, gas costs collected through the GCA and costs collected through the DSMCA are removed. These costs are tracked and recovered through adjustment mechanisms and are therefore excluded for purposes of determining the Company's base rates. Also, accounting adjustments are made to remove out-of-period amounts that are recorded in the HTY but that are applicable to prior periods, or if amounts are applicable to the HTY that were recorded after the HTY, they are included.

Q. PLEASE DESCRIBE WHAT IS MEANT BY "COMMISSION-ORDERED ADJUSTMENTS."

A. Commission-ordered adjustments are made to comply with rate recovery policies and principles established by the Commission pursuant to orders issued in prior Public Service rate proceedings. For example, advertising expenses incurred for marketing, promotional, community relations, image, and political purposes are costs that the Commission has specifically ordered be eliminated from the regulated cost of service study in the past. If we ever wished to include such items in the cost of service, we would explicitly request Commission authorization to do so.

Q. PLEASE DESCRIBE WHAT IS MEANT BY "*PRO FORMA* ADJUSTMENTS."

A. *Pro forma* adjustments are made to test year results in order for that period to be representative of future conditions. Adjustments are made for known and measurable or contracted for changes occurring both in the test year (in-period adjustments) and outside the test year (out-of-period adjustments). *Pro forma* adjustments are typically made to a HTY cost of service in order to make the HTY more representative of the costs the Company expects to incur during the period of time in which new rates will be in effect (sometimes referred to as the "Rate Year"). For example, wage increase adjustments for increase in the test year and outside the test year are *pro forma* adjustments. The Commission traditionally has allowed *pro forma* adjustments to O&M expense that are known and measurable occurring one year after the end of the HTY.

Q. WHAT ADJUSTMENTS AND REGULATORY PRINCIPLES, AS ADOPTED IN THE COMPANY'S PREVIOUS RATE CASES, ARE INCORPORATED INTO THE HTY COST OF SERVICE STUDY PRESENTED IN THIS RATE CASE?

A. I have incorporated the following adjustments and regulatory principles, as previously established by the Commission in past rate cases, into the CTY and the 2021 HTY revenue requirements study presented in Attachments APF-1 and APF-2.

A. <u>Rate Base</u>

- Rate Base is calculated using a 13-month average balance method for the CTY, except for Cash Working Capital, and the non-plant related Accumulated Deferred Income Tax ("ADIT") balances.
- Rate Base is calculated using a year-end balance method for the 2021 HTY, except for Cash Working Capital and non-plant rate base balances.
- The gas stored underground inventory balance is collected through the GCA and has been eliminated from rate base.
- Materials and supplies inventory and other non-plant rate base items, such as customer deposits and customer advances for construction, are calculated using a 13-month average of month-end balances.
- The plant-related ADIT balances are calculated using 13-month average balances and the non-plant related ADIT balances are calculated using an average of the beginning of the year and the end of year balances ("BOY/EOY") in the CTY, and are prorated in compliance with Internal Revenue Service ("IRS") guidelines and also incorporates the effects of bonus depreciation as applicable.
- The ADIT balances are a net reduction to rate base, as opposed to a cost-free component in the capital structure. The ADIT balances are functionalized. Adjustments to ADIT include eliminating amounts that are not included in the cost of service calculation and adjustments related to plant adjustments.
- Full normalization is the method of accounting for income taxes, allowing the Company to provide for deferred taxes on all book/tax timing

differences, including any offset to ADIT for net operating losses ("NOL") or NOL carry-forward.

- Adjustments to rate base and specific assignment of plant to either the Commission jurisdiction or the FERC jurisdiction are made using the 13-month average or year-end balances to match the method of measuring rate base.
- Common plant is allocated to the Gas Department based on a study of all common plant assets and assigning an allocation method for each type of asset.
- Construction Work in Progress ("CWIP") is included in rate base with an Allowance for Funds Used During Construction ("AFUDC") addition to earnings.
- ADIT and Deferred Income Tax expense are adjusted for the interest on CWIP.
- Capital lease assets are not included in rate base.
- Plant Held for Future Use ("PHFU") is included in rate base.
- An adjustment is made to eliminate a portion of the materials and supplies inventory balance allocated to construction-related projects.
- Cash working capital components consist of gas purchased for resale, O&M expenses both directly incurred by the Company and charges from XES, paid time off, taxes other than income, federal and state income taxes, and franchise and sales taxes.
- Cash working capital factors are based on a lead-lag study.
- Deductions from rate base include customer deposits and customer advances for construction.

B. Revenue

- Retail base rate revenue does not include revenues expected to be billed through various recovery mechanisms: GCA, gas DSMCA, and PSIA. Any costs or incentives recovered through these recovery mechanisms are eliminated from the cost of service.

- The revenue collected for the low-income program that are included in the Service & Facility monthly charge are not included in base rate revenue. These revenues are tracked on the balance sheet along with the program expenditures.

- Retail base rate revenue does not include unbilled revenue or adjustments to account for customer additions or losses to the calendar year sales or base rate revenues.

- Customers are annualized at the year-end level when rate base is presented at the year-end level (e.g., in the HTY).

- Gas sales are normalized for weather.

- Adjustments are made to Other Gas Revenue to exclude revenues related to residential late payments, rate refunds, Quality of Service Plan bill credits, and Demand Side Management ("DSM") incentives.

- Residential late payment revenues are excluded from the cost of service calculation, as these revenues are donated to Energy Outreach Colorado ("EOC").

C. Fuel and O&M Expenses

- Purchased Gas costs are eliminated from the determination of the revenue requirement.

- Labor expenses recorded in purchased gas expenses are reclassified to FERC Account 807, Other Gas Supply.

- Expenses associated with the Front Range Pipeline are eliminated from the cost of service.

- Include adjustments to O&M expense for known and measurable changes occurring both in the Test Year (in-period adjustments), and outside the Test Year (out-of-period adjustments).

- No out-of-period adjustments to O&M expense have been made to the cost of service for items expected to occur more than one year after the end of the Test Year.

- Include merit increases for bargaining unit and non-bargaining unit employees that occurred during the Test Year and within one year after the end of the Test Year, including related adjustments to payroll taxes.

- Accounting adjustments are made to eliminate or add expenses to accurately state the Test Year.

- Interest on customer deposits is included in Customer Operations expense.

- DSM costs are eliminated from the cost of service.

- Advertising expenses related to marketing, promotion, community relations, image, and political ads are eliminated.

- Advertising expenses related to safety, conservation, and customer programs are included in the cost of service.

- All lobbying expenses and donations are excluded from the cost of service.

- Employee expenses that do not meet accounting guidelines as recoverable from customers are eliminated;

- Discretionary pay is eliminated from the cost of service.

- A portion of aviation expenses associated with the corporate aircraft are eliminated.

- Regulatory commission expenses associated with the Commission administration fees are annualized at the most current level.

- 50% of investor relations expenses are eliminated;

- Cost allocation between regulated and non-regulated business activities is based on the Cost Allocation and Assignment Manual and the Fully Distributed Cost Study filed in this rate case as sponsored by Company witness Mr. Ross Baumgarten.

D. <u>Depreciation and Amortization Expense</u>

- Adjustments to depreciation and amortization expense are made to correspond with adjustments made to plant and accumulated depreciation, or to exclude amounts not included in the cost of service calculation.

- Include amortization of the previously approved regulatory asset for the deferral of Damage Prevention Expenses.

- Include amortization of the previously approved regulatory asset for the deferral of property taxes.

- Include amortization of the previously approved regulatory asset for the deferral of Pension Expenses.

- Include amortization of the previously approved regulatory asset for the environmental remediation costs at the Boulder and Denver manufactured gas plan sites.

- Depreciation expense are annualized at the year-end level when a year-end rate base methodology is used.

E. <u>Taxes Other Than Income Taxes</u>

- Adjust property taxes for changes to property taxes that are expected to occur in the Test Year.

- Eliminated property taxes associated with Front Range Pipeline.

- Adjustments to payroll taxes are made to correspond with the labor adjustments made to O&M expense.

F. <u>Income Taxes</u>

- Current federal and state income taxes are calculated as follows: taxable income less synchronized interest expense, temporary additions/deductions are added, and permanent tax differences are added, then state and federal income taxes are applied.

- Federal and State income tax rates reflect current rates.

- Adjustments to current and deferred income tax expense are made to correspond with adjustments made to plant or to exclude amounts not included in the cost of service calculation, and to include interest on CWIP.

- Include adjustments to income taxes and deferred income taxes if the Company is in a NOL tax position.

- Income tax credits are included in total income tax expense.

G. AFUDC Offset to Earnings

- Include an offsetting adjustment to earnings for AFUDC due to CWIP being included in rate base.

- AFUDC addition to earnings is based on actual test-period expenses and is not annualized if rate base is calculated using a 13-month average; if rate base is calculated using a year-end balance, AFUDC addition to earnings is annualized at the year-end level.

H. Capital Structure

- Capital structure is based on 13-month average balances.

- Short-term debt is included in the capital structure when CWIP is included in rate base.

- Adjustments are made to the capital structure to eliminate the following items: 1) notes payable/receivable with subsidiaries; 2) investment in subsidiaries; 3) subsidiary retained earnings; 4) net non-utility plant; 5) other investments at cost; 6) other funds; and 7) other comprehensive income ("OCI").

- The cost of debt is calculated using the par value method and corresponds with the debt balances in the capital structure, and includes bond premiums or discounts, underwriting expenses, other expenses of issue, and amortization of the long-term credit facility.

I. Jurisdictional Allocation Factors and Direct Assignments

- The allocation between the Gas Department retail and wholesale jurisdictions is performed on a line-by-line basis for both rate base and earnings, and based on the methodology last approved by the Commission.

I have prepared Attachment APF-9 to summarize the regulatory principles and adjustments included in the CTY and 2021 HTY cost of service studies presented in this rate case, including identifying the Company witnesses that support those adjustments.

Q. ARE ANY REGULATORY AMORTIZATIONS APPROVED BY THE COMMISSION IN THE 2020 GAS COMBINED RATE CASE INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS RATE CASE?

A. Yes, there were several regulatory amortizations approved in the 2020 Gas Combined Rate Case that are included in the cost of service studies presented in this case. The majority of the regulatory amortizations approved in the 2020 Gas Combined Rate Case have three (3) year amortization periods, beginning with the effective date of rates in that proceeding, November 1, 2020, and will expire in October 2023. The regulatory amortizations from the 2020 Gas Combined Rate Case that have three (3) year amortization periods include:

- Property Tax expenses;
- Pension expenses;
- Damage Prevention expenses;
- Denver and Boulder Manufactured Gas Plant ("MGP") expenses; and
- Rate Case expenses.

For those regulatory amortizations with three (3) year amortization periods that expire in October 2023, the Company proposes to eliminate any amortization expense in the CTY and add any unamortized amounts to the regulatory asset balances included in this case, and amortize the remaining amount over a new period proposed in this case, as discussed in additional detail later in my Direct Testimony.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE TREATMENT OF ANY OF ITS COSTS OR REVENUES IN THIS PROCEEDING FROM WHAT WAS APPROVED IN THE 2020 GAS COMBINED RATE CASE?

A. Yes. The 2020 Gas Combined Rate Case was resolved via a comprehensive and unopposed negotiated settlement. The Company is therefore proposing several changes in the treatment of its costs in this proceeding from what was approved in the 2020 Gas Combined Rate Case. First, the Company is proposing to change the treatment of the prepaid pension asset and the other regulatory assets and liabilities in rate base related to employee benefits, including: Financial Accounting Standard No. 106, Accounting for Postretirement Benefits Other than Pensions (“FAS 106”);[3] Financial Accounting Standard No. 112, Accounting for Postemployment Benefits (“FAS 112”);[4] and non-qualified pension. The Company proposes to earn a full return at the WACC on the balance of over/under funding on all pension and other postemployment benefits, net of regulatory amortizations, consistent with the decision of the Denver County District Court and the Commission on this matter in Proceeding No. 17AL-0363G (the Company’s 2017 Gas Phase I rate case). The change in the treatment of the prepaid pension asset and the other employee benefit regulatory assets and liabilities in rate base is

[3] FAS 106 focuses principally on postretirement health care benefits, referred to as Retiree Medical.

[4] Postemployment benefits are all types of benefits provided to former or inactive employees, their beneficiaries, and covered dependents. Those benefits include, but are not limited to, salary continuation, supplemental unemployment benefits, severance benefits, disability-related benefits (including workers' compensation), job training and counseling, and continuation of benefits such as health care benefits and life insurance coverage.

explained in more detail in the Direct Testimony of Company witness Mr. Schrubbe.

Second, as I discuss later in my Direct Testimony, the Company proposes to include the unamortized balances of regulatory assets and liabilities in rate base and earn a full return at the WACC. These regulatory assets and liabilities include:

- Rate Case expenses;
- Pension expenses;
- Property Tax expense;
- Damage Prevention expenses;
- Manufactured Gas Plants ("MGP") Expenses;
- Colorado State Income Tax rate change.

Third, the Company is proposing to recover the amount of Annual Incentive Pay ("AIP") at target in this case, not the actual amounts paid, nor is the Company proposing to limit the recovery further. In addition, the Company is proposing to include the portion of executive Long-Term Incentive ("LTI") that is associated with both the time-based component and the environmental component. Company witness Mr. Knoll discusses the amount of AIP and LTI requested in this case.

Finally, as discussed by Company witness Mr. Johnson, the Company is proposing to calculate the cost of long-term debt using the 13-month average, as opposed to a point in time at the end of the Test Year.

V. RATE BASE

A. Rate Base Methodology

Q. CAN YOU PROVIDE ADDITIONAL DETAIL REGARDING THE METHOD OF DETERMINING RATE BASE THE COMPANY IS PROPOSING IN THIS PROCEEDING?

A. Yes. The CTY rate base was calculated using a 13-month average balance methodology, except for non-plant related ADIT, and Cash Working Capital. The non-plant related ADIT balances were calculated using a BOY/EOY average. Cash Working Capital was calculated based on the test period operating expenses multiplied by a cash working capital factor premised on a lead-lag study, which is discussed in more detail in the following section of my testimony.

Q. WHAT METHOD OF DETERMINING RATE BASE DID THE COMPANY USE FOR THE INFORMATIONAL 2021 HTY?

A. The 2021 HTY cost of service rate base is calculated using a year-end balance methodology for all items except for the following: (1) materials and supplies inventory balances and non-plant rate base items are calculated using a 13-month average balance methodology; (2) pension and employment benefit-related assets are calculated using a 13-month average balance methodology; and (3) Cash Working Capital is calculated using the same lead-lag factors as was used in the CTY. Each of these items is discussed later in my Direct Testimony.

Q. PLEASE DESCRIBE THE BASIS FOR THE GROSS PLANT, PHFU, CWIP, AND OTHER PLANT-RELATED ITEMS THAT ARE INCLUDED IN THE COST OF SERVICE STUDIES FILED IN THIS RATE CASE.

A. The projected capital expenditures and forecasted in-service dates, along with other relevant information, were used in the development of the plant-related information included in the CTY cost of service. Company witness Ms. Wold discusses how the projected capital expenditures, plus other information, are used to derive the monthly gross plant, PHFU and CWIP balances. In addition, several other plant-related items were then derived from this information, including accumulated reserve for depreciation and amortization, ADIT, depreciation and amortization expense, additions and deductions for current income taxes, deferred tax expense, and AFUDC. The plant in-service balances, and plant-related items included in the 2021 HTY cost of service are based on the Company's actual books and records at June 30, 2021.

Q. PLEASE DESCRIBE HOW THE INFORMATION PRESENTED BY MS. WOLD CORRESPONDS TO THE RATE BASE BALANCES PRESENTED IN ATTACHMENT APF-1.

A. The plant and accumulated reserve balances presented on Attachment APF-1, Schedule 100 correspond with the balances presented by Company witness Ms. Wold on Attachments LJW-1 and LJW-2. Company witness Ms. Wold presents the calculation of the 13-month average balances for plant in service and accumulated reserve for depreciation and amortization on Attachment LJW-3.

Q. PLEASE DISCUSS THE BASIS FOR THE ALLOCATION OF COMMON PLANT THAT IS INCLUDED IN THE GAS DEPARTMENT RATE BASE PRESENTED IN THIS RATE CASE.

A. Annually, the Company prepares a study to determine the amount of Common Plant that should be assigned to the electric, gas, thermal energy and non-utility operations. Allocation factors are calculated from the study, which are then applied to the Common Plant balances included in rate base. The 2020 allocation factors were used in the cost of service studies presented in this rate case.

Q. HOW WAS CWIP TREATED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS RATE CASE?

A. CWIP is included in rate base to correspond to the inclusion of short-term debt in the capital structure, as presented by Company witness Mr. Johnson, consistent with the Commission order in the Company's 2019 Electric Phase I rate case (Proceeding No. 19AL-0268E, "2019 Electric Phase I"). The Company has included CWIP in rate base in this case based on the amount of accumulated capital expenditures plus AFUDC related to capital projects in progress, but not yet in-service, as of December 31, 2022. The Commission has a long-standing regulatory practice that when CWIP is included in rate base, there is an AFUDC offset to earnings, going back to at least Commission Decision No. 78811, dated October 4, 1971, in Application No. 24900. The AFUDC offset to earnings is based on the CWIP included in the Test Year.

Q. PLEASE DESCRIBE THE AFUDC OFFSET TO EARNINGS IN THIS CASE?

A. Historically, the Commission has a long-standing ratemaking policy that if CWIP is included in rate base, then an AFUDC offset to earnings is required. As previously discussed, the Company has included CWIP in the CTY in this case, and therefore has included an AFUDC offset to earnings, as shown on Attachment APF-1, Schedule 201. In addition, when year-end rate base is used, as in the 2021 HTY, AFUDC is annualized at the year-end level, as of June 30, 2021, to match the year-end CWIP balance. The adjustment to annualize AFUDC is shown on Attachment APF-2, Schedule 225.

Q. PLEASE DESCRIBE THE BASIS FOR THE BALANCES ASSOCIATED WITH MATERIALS AND SUPPLIES, CUSTOMER DEPOSITS, AND CUSTOMER ADVANCES FOR CONSTRUCTION INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS RATE CASE.

A. The balances used in the CTY for materials and supplies (Attachment APF-1, Schedule 133, customer deposits (Attachment APF-1, Schedule 230), and customer advances for construction (Attachment APF-1, Schedule 110) were all based on the actual 13-month average balances during the test period ending June 30, 2021, as a proxy for the CTY. The balances used in the 2021 HTY cost of service are shown on Attachment APF-2, Schedules 133, 230 and 110, and are all based on the actual 13-month average balances during the test period, consistent with Commission precedent.

Q. PLEASE DESCRIBE THE BASIS FOR THE ADIT BALANCES INCLUDED IN RATE BASE IN THIS RATE CASE.

A. The ADIT balances included in rate base consists of both plant and non-plant related items booked to FERC Accounts 281, 282, 283, and 190. Also, the ADIT balances include the impact of implementing the TCJA effective January 1, 2018. As previously mentioned, the plant-related ADIT balance in the CTY is presented using a 13-month average, and the non-plant ADIT balance is presented using a BOY/EOY average. In addition, the ADIT balances in the CTY are prorated consistent with IRS guidelines and incorporate the effects of bonus depreciation as applicable. The ADIT balance in the 2021 HTY is at the year-end level.

The plant-related ADIT balance is primarily due to the book-tax timing difference relating to depreciation. The book plant-related ADIT balances are detailed on Attachment APF-1, Schedule 101. The non-plant ADIT balance is primarily due to the book-tax timing differences relating to pensions and benefits and other non-depreciation related items, as discussed by Company witness Ms. Koch. The Company has detailed the ADIT balance by each non-plant income tax addition/deduction (also known as “Schedule M items”) and has functionalized the plant-related ADIT items. This level of detail allows the Company to accurately assign the ADIT balances to the correct jurisdiction. The details of the non-plant ADIT balances are presented on Attachment APF-1, Schedule 115. The Company has also correspondingly presented the deferred income tax expense and additions/deductions to current income for both plant and non-plant related items consistent with the ADIT balances.

B. Year-End Rate Base Methodology for HTY

Q. PLEASE PROVIDE BACKGROUND ON THE USE OF YEAR-END RATE BASE IN AN HTY BEFORE THE COMMISSION.

A. The Commission first adopted the use of year-end rate base in setting rates for Public Service's gas and electric services in 1974, Decision No. 85724, Investigation and Suspension ("I&S") Docket No. 868. In every Public Service rate case for nearly three decades following that decision, the Commission continuously reaffirmed its policy of using year-end rate base for setting base rates for Public Service.

In Proceeding No. 02S-315EG ("2002 Rate Case"), however, the Commission approved a Settlement Agreement in which the settling parties agreed to use a 13-month average rate base in developing the settled rates. The 2002 Rate Case was unique because it was a combination gas, electric, and steam case and the Company's first electric rate case for nearly ten years since Proceeding No. 93S-001EG, which included several years of performance-based rate regulation resulting from the Company's merger with Southwestern Public Service Company. For the Company's Gas business, however, the Commission had continued to approve the use of year-end rate base, after a full hearing on the merits, in each of the Company's previous three gas-only rate cases prior to the 2002 Rate Case, in Proceeding Nos. 96S-290G, 98S-518G and 02S-422G.

Since the 2002 Rate Case Settlement, the majority of separate gas and electric rate cases filed by Public Service have settled, including the 2014 Rate Case. As is typical under rate case settlement agreements, the settling parties expressly agree that the provisions resolving issues in the determination of revenue requirements have no precedential effect in the Company's next rate case. It was not until the 2012 Gas Rate Case that the Commission, again after a full hearing on the merits, approved the use of year-end rate base for the HTY cost of service approved in that case. The Commission, in Decision No. C13-1568, in determining the rate base methodology, noted that "[i]n the past, the Commission has based its selection on the circumstances of each specific case." In the 2012 Gas Rate Case, the Commission considered whether the ROE was being reduced, and the Commission relied upon this factor in selecting year-end rate base.

Beginning with the fully litigated 2015 Gas Phase I Rate Case, Proceeding No. 15AL-0135G ("2015 Gas Phase I") and continuing with the 2017 Gas Phase I Rate Case, Proceeding No. 17AL-0363G ("2017 Gas Phase I"), the Commission ordered that rate base be calculated using a 13-month average. In the 2015 Gas Phase I, the Commission made an exception to the 13-month average with the net investment in the Cherokee pipeline, which was calculated using year-end rate base, because the asset was placed in service in October 2014 such that only one-quarter of the Company's investment in this asset would be included in rate base and earn a return if the 13-month average was used.[5]

In the 2019 Electric Phase I, the Commission ordered a rate base calculated using the historical year-end December 31, 2018, plus a 13-month average of the capital additions through August 31, 2019 (the end of the current test year in that

[5] The Commission upheld the Administrative Law Jude's recommendation to adopt a 2014 Historical Test Year in the 2015 Gas Phase I, Decision No. C16-0123, adopted January 27, 2016.

proceeding). In the Company's 2020 Gas Combined Rate Case, also a fully settled case, the Commission approved a rate base calculated using the year-end September 30, 2019, plus a known and measurable post-test year capital adjustment to the revenue requirement associated with the Tungsten to Blackhawk capital project investment as of April 30, 2020.

Q. WHAT DOES ALL OF THE HISTORY REGARDING THE COMMISSION-APPROVED RATE BASE METHODOLOGY INDICATE TO YOU?

A. There is obviously a long history with this Commission regarding the rate base methodology used for setting base rates for Public Service. Generally, the use of a year-end rate base was the predominant methodology for decades. More recently, there are instances where the Commission has approved a 13-month average rate base. However, there are also instances where the use of the year-end methodology continues to be used and approved.

Q. WHY IS IT APPROPRIATE TO USE YEAR-END RATE BASE IN DETERMINING THE REVENUE REQUIREMENT FOR THE HTY FILED IN THIS RATE CASE?

A. As was mentioned earlier, the main goal when developing a cost of service study is to present costs that are representative of those expected to be incurred during the time rates from the rate case will be in effect. In other words, the costs included in the cost of service are representative of the cost of ongoing operations. This main goal then informs the rate base methodology that is used depending on whether the test year is a future test year or a historic test year.

In a future test year, the time period that is used to measure the cost to provide service coincides with the time the rates are in effect. In that case it is appropriate to use a 13-month average rate base methodology because, as plant is added to the system, not all rate base will be in service during the Rate Year. As an example, consider a piece of equipment that is placed into service in the last month of a future test year, and the rate year coincides with the test year. It would be inappropriate to charge customers the full value of that piece of equipment since they only got the benefit of that equipment for one month. In the case of a historic test year though, the test year and rate year do not coincide. The rate year occurs after the test year.

In a historical test year, the 13-month average methodology is inappropriate because regardless of what month in the test year plant is placed into service, customers are getting the full benefit of the plant during the rate year. Going back to the example above, customers are getting the full benefit of the equipment placed in service in the last month of the test year because it is in service for all months of the rate year. As such, the full cost of the equipment should be included in the rates charged during the rate year, which is what a year end rate base methodology accomplishes. Where an HTY is used to set rates, a year-end rate base more closely reflects the rate base of the Company when rates are actually in effect. As discussed by several of the Company's witnesses, the Company is making significant investments related to its Gas business. By using year-end rate base for the HTY, customers are charged the full cost of the assets for which they are getting the full benefits. Public Service also begins to recover some of these significant investments during the HTY, but not all.

As described above, the CTY is proposed to capture these significant investments, and to include rate base balances that more closely match the time when rates are in effect. The 13-month average balance method for valuing rate base was therefore used in the CTY. At this point, base rates from this case are expected to be effective in November 2022, which is much closer to the rate base balances used in the 2022 CTY (i.e., mid-year 2022) than the year-end balances used in the 2021 HTY, which are as of June 30, 2021. The Company's rate base balances presented in the 2021 HTY are not representative of the rate base level when rates are effective.

Finally, the Company does not agree that year-end rate base with an HTY is only appropriate where "extraordinary conditions" exist, as was first suggested in the 2015 Gas Phase I Proceeding No. 15AL-0135G, and the long-standing use of year-end rate base for HTYs by the Commission before that case supports the use of year-end rate base.

Q. IF THE COMMISSION CONTINUED TO USE THE NEWER "EXTRAORDINARY CIRCUMSTANCES" STANDARD, WOULD PUBLIC SERVICE MEET THE STANDARD?

A. Yes. Setting aside the disagreement with "extraordinary circumstances," the Commission explicitly noted that earnings attrition would serve as evidence of "extraordinary conditions" that would support the use of year-end rate base. As shown in the Table APF-D-4 below, the Company has not earned its authorized return on equity over the last several years, as reported in its Annual Report to the Commission (also known as the Appendix A). The Company implemented new base rates from the 2020 Electric Phase I in April 2021. As previously mentioned, the 2020 Gas Combined Rate Case was based on a rate base methodology of year-end September 2019 balances, plus an adjustment for the Blackhawk-Tungsten project as of April 30, 2020. The Company still earned substantially under its authorized return on equity.

Table APF-D-4

	2015	*2016*	*2017*	*2018*	*2019*	*2020*
Earned ROE[6]	6.04%	7.34%	6.64%	8.49%	6.81%	8.78%
Authorized ROE	9.50%	9.50%	9.50%	9.35%	9.35%	9.20%

Company witnesses Ms. Trammell and Mr. Berman discusses the reasons why our opportunity to earn our authorized return on equity is diminished. With the growth in capital expenditures in 2022 necessary to serve customers, discussed by several Company witnesses in this rate case, setting rates based on a 2021 HTY and using a 13-month average rate base methodology will likely result in the Company being in an under-earning position because it will not have a reasonable opportunity to recover its costs of service in a timely manner. Therefore, the year-end rate base methodology should be used for developing the HTY revenue requirement.

[6] The source of the numbers is Public Service's Annual Report to the Commission.

C. Transfer of Costs into Base Rates from Rider Mechanisms

Q. PLEASE SUMMARIZE WHAT COSTS THE COMPANY PROPOSES TO TRANSFER INTO BASE RATES THAT WERE PREVIOUSLY RECOVERED FROM CUSTOMERS THROUGH ANOTHER MECHANISM.

A. The Company is proposing to transfer the costs formerly recovered in the PSIA into base rates in this case.

Q. PLEASE DISCUSS THE COSTS FORMERLY IN THE PSIA INCLUDED IN THIS RATE CASE.

A. I discussed earlier in my testimony, as part of the settlement in the PSIA Extension Filing, the 2021 PSIA revenue requirement was converted to a GRSA-P that is being rolled into base rates in this case. The GRSA-P being rolled into base rates in this case contains the forecasted costs for all PSIA projects placed into service through 2021.

Q. IS THE REVENUE REQUIREMENT INCLUDED IN THE GRSA-P AND PROPOSED FOR INCLUSION IN BASE RATES IN THIS PROCEEDING BASED ON ACTUAL PSIA COSTS?

A. No. The revenue requirement currently in the GRSA-P is based on the Company's November 1, 2020 filing of a forecast of the 2021 PSIA rider revenue requirement in Proceeding No. 20AL-0503, plus the true-up of 2020 PSIA costs. The only difference between the revenue requirement in the 2021 PSIA rider and the GRSA-P is that the 2021 PSIA included the true-up for the 2019 PSIA rider, whereas the GRSA-P includes the true up for the 2020 PSIA rider.

Q. WILL THE COSTS IN THE GRSA-P BE TRUED UP TO ACTUAL?

A. Yes. As agreed in the PSIA Settlement, the 2021 PSIA revenue requirement in the GRSA-P will be trued up to actual costs.

Q. HOW DOES THE COMPANY PLAN TO FULLY REFLECT THE 2020 PSIA TRUE UP IN RATES GIVEN THE NOVEMBER 1, 2022 RATE EFFECTIVE DATE IN THIS CASE?

A. When the rates from this case are implemented on November 1, 2022, the GRSA-P will not be set to zero. Rather, the GRSA-P will continue to contain the 2020 PSIA rider true up but the 2021 GRSA-P revenue requirement will be transferred to base rates. The GRSA-P will continue to be charged to customers; however, since the 2020 PSIA true up was a refund, the GRSA-P will be a credit on customers' bills starting November 1, 2022.

Q. HOW DOES THE COMPANY PROPOSE TO PROVIDE THE 2021 PSIA TRUE UP TO CUSTOMERS?

A. The Company plans to keep the GRSA-P in place in 2023 to provide the 2021 PSIA rider true up and the GRSA-P true up to customers. On April 1, 2022, the Company will be filing the actual 2021 PSIA revenue requirement with the Commission. This revenue requirement true up, along with the associated revenue true up, will then replace the 2020 PSIA true up in the GRSA-P for 2023. Since the GRSA-P that became effective on January 1, 2022 includes the same revenue requirement as the 2021 PSIA rider, the 2021 PSIA rider true up will also be truing up the 2022 GRSA-P revenue requirement.

Q. WHAT REVENUE REQUIREMENT RELATED TO PSIA COSTS HAVE YOU CALCULATED?

A. I have calculated the portion of the 2022 CTY revenue requirement related to pipeline safety and integrity for Mr. Wishart for use in his class allocation model. That includes all projects previously authorized by the Commission in the 2021 PSIA rider plus additional pipeline safety and integrity projects for 2022. I also note that the Company is not requesting recovery of any PSIA costs deferred in 2022 in this proceeding; those costs will remain in the deferral until the next rate case. As I mentioned previously, the deferral will end with the implementation of rates in this case, so recovery of 2022 PSIA projects will occur through base rates for the last two months of 2022.

Q. PLEASE EXPLAIN IN MORE DETAIL HOW THE PSIA DATA MR. WISHART USES IS SOMEWHAT DIFFERENT FROM THE AMOUNT INCLUDED IN THE GRSA-P.

A. The PSIA revenue requirement used in Mr. Wishart's model is the revenue requirement for PSIA-qualifying projects forecasted to be placed in service through 2022. This revenue requirement includes the costs of the projects in the GRSA-P plus the costs of projects that would have been included in the PSIA in 2022 had the rider continued. As Company witness Mr. Wishart fully describes in his Direct Testimony, the Company is proposing to change the allocation of PSIA costs in the class cost of service. In order to accomplish this allocation, Mr. Wishart required the cost of PSIA qualifying projects to be included in the CTY revenue requirement. The revenue requirement for all PSIA qualifying projects in the CTY is $131,811,378.

D. Rate Base Adjustments

Q. IN THIS PROCEEDING, HAS THE COMPANY MADE ADJUSTMENTS TO ITS PLANT IN-SERVICE BALANCES OTHER THAN THOSE APPROVED BY THE COMMISSION IN PRIOR RATE CASES?

A. Yes. Adjustments were made to reclassify a common general project related to the Advanced Grid Intelligence and Security ("AGIS") projects to move it out of Gas Common General plant in-service and move it to the Electric Department.

Q. PLEASE DESCRIBE THE ADJUSTMENT REMOVING THE INVESTMENT ASSOCIATED WITH AGIS PROJECTS FROM THE COST OF SERVICE STUDY PRESENTED IN THIS RATE CASE.

A. In general, the Field Area Network component of the AGIS projects is classified as a common general asset. This is the appropriate classification, because this component will benefit Public Service's electric and gas customers. However, the benefit to the Gas Department and gas customers will not occur when this asset is initially put in service. Therefore, the Company added 100 percent of this investment to the Electric Department cost of service study and has removed 100 percent of this investment from the Gas Department cost of service study presented in this rate case. Adjustments were made to Gas Common General plant in-service and accumulated reserve for depreciation. This approach is consistent with the adjustment made in the 2020 Gas Combined Rate Case, where zero percent of these costs were included in the Gas Department rate base. The adjustments to eliminate the AGIS projects are shown on Attachment APF-1, Schedule 137.

Q. WILL THE COMPANY EVER RECLASSIFY THE PLANT-RELATED COST OF AGIS ITEMS TO ALLOCATE A PORTION OF COSTS TO THE GAS DEPARTMENT?

A. Yes, if and when the Field Area Network ("FAN") component of the AGIS initiative is used by the Gas Department, we may reclassify it as a common general asset and seek recovery at that time. However, we are not making that request in this rate case.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO OTHER RATE BASE BALANCES THAT FOLLOW PREVIOUSLY ESTABLISHED RATEMAKING PRINCIPLES?

A. Consistent with prior Commission decisions, an adjustment was made to eliminate a portion of the materials and supplies inventory balance allocated to construction-related projects. This adjustment is shown on Attachment APF-1, Schedule 133.

E. <u>Regulatory Assets and Liabilities</u>

Q. PLEASE DESCRIBE THE BASIS FOR THE REGULATORY ASSETS AND LIABILITIES INCLUDED IN RATE BASE .

A. As previously discussed, the Company has incurred costs associated with MGP, property taxes, pension expense, rate case expenses, and damage prevention work that have been deferred as regulatory assets, as approved by the Commission in prior rate cases. The Company is requesting to amortize these costs in this rate case in the manner I describe later in my Direct Testimony and earn a return on the unamortized balance in rate base. The unamortized balances of these regulatory assets and liabilities have been included in rate base in the Test Year. The regulatory assets included in rate base are shown on Attachment APF-1, Schedule 123.

Q. WHY IS RATE BASE TREATMENT OF THE REGULATORY ASSETS APPROPRIATE?

A. The Commission's approval to defer these items creates a regulatory asset that is then amortized off as an expense over several years. Accordingly, where a regulatory asset is created, the Company pays for the service at the time the costs are incurred but these costs are not recovered from customers. Rather, the costs are deferred in the regulatory asset, which is created by the Commission's approval to defer the costs. These costs remain in the regulatory asset, without any carrying costs, until they are brought forward for recovery in a subsequent rate proceeding. Including the unamortized portion of the regulatory asset in rate base provides a return until the cost is recovered in the period amortized to compensate investors for financing these assets. A return at the authorized WACC is appropriate because it represents the components of the carrying costs of these assets, i.e., the Company's weighted average debt and equity. These regulatory assets must be financed, no differently than investments in plant.

Q. PLEASE DESCRIBE THE BASIS FOR THE PREPAID PENSION ASSET BALANCE INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS CASE.

A. As discussed by Company witness Mr. Schrubbe, the Prepaid Pension Asset is included in rate base in the CTY and the 2021 HTY presented in this rate case. The Company is presenting the Prepaid Pension Asset as the gross balance. The related

ADIT associated with the Prepaid Pension Asset is included in the ADIT balances, as discussed later in my Direct Testimony. This presentation is different than in prior gas rate cases, when the Company presented the net Prepaid Pension Asset, net of ADIT. The Company is proposing to include the 13-month average of the Prepaid Pension Asset in rate base and to earn a full return on the balance. The basis for the Prepaid Pension Asset balance is discussed more fully by Company witness Mr. Schrubbe and is shown on Attachments APF-1 and APF-2, Schedule 112.

Q. PLEASE DESCRIBE THE RETIREE MEDICAL BALANCES INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS RATE CASE.

A. The retiree medical balance associated with FAS 106 is included in rate base in the cost of service studies presented in this case. The Company is proposing to include the 13-month average retiree medical balance in rate base and to earn a full return on the balance. The Commission approved this same adjustment in the 2017 Gas Phase I and 2019 Electric Phase I. The basis for the retiree medical balance is discussed more fully by Company witness Mr. Schrubbe and are shown on Attachments APF-1 and APF-2, Schedules 114.

Q. PLEASE DESCRIBE THE POST EMPLOYMENT BENEFIT AND NON-QUALIFIED PENSION LIABILITY BALANCES INCLUDED IN THE COST OF SERVICE STUDIES PRESENTED IN THIS RATE CASE.

A. As previously mentioned, the Company is requesting approval to include the 13-month average balance of the Regulatory Liabilities associated with the Accounting for Postemployment Benefits, FAS 112, and the non-qualified pension in rate base in this rate case, consistent with including the Prepaid Pension Asset and the retiree medical asset in rate base. The basis for the FAS 112 and the non-qualified pension liability balances are discussed more fully by Company witness Mr. Schrubbe and are as shown on Attachments APF-1 and APF-2, Schedules 111 and 112.

F. Tax Normalization and ADIT

Q. FROM A RATEMAKING PERSPECTIVE, HOW DOES THE COMPANY ACCOUNT FOR INCOME TAXES?

A. The Company uses the tax normalization method to account for income taxes. Tax normalization refers to the practice of providing deferred taxes on all book/tax timing differences. Timing differences are transactions that impact book income and taxable income in different periods. This issue arises because taxes are not always required to be paid by a utility at the same time the tax obligation is incurred. In contrast, "flow-through" is the accounting method which, for ratemaking purposes, provides for income tax expense payable currently to be included as cost of service income tax expense for the period, and deferred income taxes are not recorded.

The classic example of a timing difference is related to depreciation. Book depreciation is recorded based on a straight-line basis. Current taxes are reduced by the value of the accelerated depreciation deduction multiplied by the tax rate. Accelerated depreciation is also known as tax depreciation. The difference between the accelerated deduction used for tax and the straight-line depreciation used for book multiplied by the tax rate is recorded as Deferred Income Tax expense. This Deferred Income Tax expense represents the tax effect of this accelerated depreciation compared to book accounting and is added to the ADIT balance. For the purpose of setting customer rates, in the cost of service study, customer rates are charged for both the current income tax expense and the deferred income tax expense. However, the ADIT balance is applied as a reduction to rate base, which gives customers credit and a reduction in rates. The reduction in rates reflects the Company's use of income taxes that have been collected from customers that are not due and payable in the Company's current taxes.

Q. HAS THIS COMMISSION APPROVED THE USE OF TAX NORMALIZATION FOR RATEMAKING PURPOSES?

A. Yes. The Company has used tax normalization associated with depreciation for setting customers' rates since 1977; however, it was not until 1993 that the Company went to full tax normalization on all timing differences. The Company's first request to use tax normalization for ratemaking purposes was in a 1975 rate case, I&S Docket No. 935. In Decision No. 87474, dated September 12, 1975, the Commission did not allow the Company to change from flow-through accounting to normalizing timing differences arising from accelerated depreciation. In its next rate case, I&S Docket No. 1116, the Company again requested approval to normalize timing differences arising from accelerated depreciation. In Decision No. 91581, dated November 1, 1977 the Commission approved tax normalization arising from accelerated depreciation. The Commission stated:

> We find that normalization assigns proper costs to both present and future customers on a basis of equality. Under flow through, by contrast, present ratepayers pay less than the straight line cost of depreciation and future ratepayers pay more than the straight line cost of depreciation. Normalization equalizes the burden between

present and future ratepayers and, accordingly, is more equitable to both.

In the 1993 Rate Case, Proceeding No. 93S-001EG, the Company requested to use full tax normalization as the method of accounting for income taxes going-forward. In Decision No. C93-1346, adopted October 14, 1993, the Commission approved full tax normalization and allowed the Company to provide for deferred taxes on all timing differences, and allowed the Company to recover a “catch-up” provision for additional deferred taxes which would have accrued had full normalization been used during past periods of time. In addition, the normalization method of accounting is provided for as “comprehensive inter-period income tax allocation” in General Instruction 18 of the FERC Uniform System of Accounts, 18 Code of Federal, Regulations, Part 101, and has been adopted by the Commission for all gas utilities in Colorado.

Q. WHAT IS BONUS TAX DEPRECIATION?

A. Bonus tax depreciation is the result of provisions in federal tax laws that allow the Company to deduct a percentage of qualifying capital investments in the first year an investment is placed in-service. For example, if the percentage allowed for bonus depreciation in the first year is 50 percent, then 50 percent of the qualifying capital investment is depreciated for tax purposes in the first year that the underlying asset is in service. The remaining 50 percent is then depreciated for tax purposes using existing accelerated depreciation schedules. Both the bonus tax depreciation deductions and the existing accelerated depreciation deductions are normalized for accounting and ratemaking purposes.

The Consolidated Appropriations Act of 2016 provided a phase-out of bonus tax depreciation with bonus tax depreciation of 50 percent on eligible assets placed into service in 2015, 2016, and 2017, bonus tax depreciation of 40 percent on eligible assets placed into service in 2018, and bonus tax depreciation of 30 percent on eligible assets placed into service in 2019. With the enactment of the TCJA, utilities were no longer eligible for bonus tax depreciation. Therefore, no bonus depreciation on additions for 2018 and forward has been factored into the calculation of ADIT.

Q. HAS THE COMPANY'S USE OF ACCELERATED AND BONUS DEPRECIATION PROVIDED SUBSTANTIAL BENEFITS TO CUSTOMERS?

A. Yes. Customers benefit from reductions to rate base that flow from the application of both accelerated and bonus depreciation. Income tax normalization accounting has led to substantial reductions in the Company's rate base due to the offsets from ADIT, and this reduced rate base in turn drives lower required earnings.

Q. HAS TAX NORMALIZATION BECOME MORE COMPLEX AS A RESULT OF BONUS TAX DEPRECIATION?

A. Yes. The Company must determine if the bonus tax depreciation results in more tax deductions than the Company can currently use. In other words, the Company must calculate if there are more deductions than net income, which results in a tax NOL. The Company has made these calculations for the CTY presented in this rate case. As shown on Attachment APF-1, Schedule 104, the Company is not in an NOL position in the CTY. However, the Gas Department does have an accumulated deferred tax asset balance due to NOLs in prior years. This NOL is fully utilized in the 2021 HTY as shown on Attachment APF-2, Schedule 104 so there is not any NOL carryforward included in the CTY.

Q. PLEASE DESCRIBE THE BASIS FOR THE ADIT BALANCES INCLUDED IN RATE BASE IN THIS RATE CASE.

A. The ADIT balance included in rate base consists of both plant and non-plant related items booked to FERC Accounts 281, 282, 283, and 190. The plant-related ADIT balance is primarily due to the book-tax timing difference relating to depreciation. The book plant-related ADIT balances are detailed on Attachment DAB-1, Schedule 101. The non-plant ADIT balance is primarily due to the book-tax timing differences relating to pensions and benefits and other non-depreciation related items, as discussed by Company witness Ms. Koch. The Company has detailed the ADIT balance by each non-plant income tax addition/deduction (also known as "Schedule M items") and has functionalized the plant-related ADIT items. This level of detail allows the Company to accurately assign the ADIT balances to the correct jurisdiction. The details of the non-plant ADIT balances are presented on Attachment DAB-1, Schedule 115. The Company has also correspondingly presented the deferred income tax expense and additions/deductions to current income taxes for both plant- and non-plant-related items consistent with the ADIT balances.

Q. PLEASE DESCRIBE THE OTHER IMPACTS OF THE TCJA ON THE AMOUNT OF ADIT IN RATE BASE THAT IS PRESENTED IN THIS RATE CASE.

A. Upon implementing the TCJA on January 1, 2018, the Company revalued its accumulated deferred tax assets and liabilities at the 21 percent federal corporate income tax rate and recorded as a regulatory asset or liability the difference between: (1) the revalued ADIT and (2) the ADIT recorded on the Company's books. These regulatory assets and liabilities contain the "excess ADIT" or "deficient ADIT" that will be collected from or returned to customers over time. For purposes of calculating rate base, the unamortized excess/deficient ADIT is included in rate base because it has not yet been recovered from or returned to customers.

As approved in the 2017 Gas Phase I and 2020 Combined Gas Rate Case, the following amortization periods of the excess/deficient balances apply:

- Plant-related excess/deficient ADIT is being returned to customers based on the Average Rate Assumption Method ("ARAM");
- The majority of non-plant ADIT was used to offset the prepaid pension asset in the 2017 Gas Phase I. The small amount of non-plant ADIT included in this case is the result of a tax return true up from 2019. This true up amount was included in the 2020 Gas Combined Rate Case with a 3 year amortization.

I have included an annual amount of amortization of the excess/deficient ADIT in the income tax calculation as I will describe later in my Direct Testimony. The annual amount of amortization of excess/deficient ADIT is shown for plant-related ADIT is included in the ADIT balances on Attachments APF-1 and APF-2, Schedule 101, and for non-plant ADIT on Attachments APF-1 and APF-2, Schedule 115.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO THE ADIT BALANCE INCLUDED IN RATE BASE.

A. There are several adjustments to the ADIT balance included in rate base in the cost of service studies presented in this rate case. First, there are several adjustments related to the plant adjustments as previously discussed. Second, there is an adjustment to the ADIT balance for the interest on the CWIP balance, and a corresponding adjustment to deferred income tax expenses. Third, adjustments have been made to eliminate ADIT balances that are related to items not included in the cost of service. For example, we have eliminated the ADIT balances associated with unbilled revenue, deferred gas costs associated with the GCA, Investment Tax Credits ("ITCs"), Financial Interpretation Number 48 "Accounting for Uncertainty in Income Taxes" ("FIN 48"), Financial Accounting Standard 109 ("FAS 109"), other comprehensive income ("OCI"), and any deferred tax assets associated with tax credits that have previously been provided to customers. The effect of these adjustments is to present ADIT in this rate case consistent with the underlying rate base items. Fourth, an adjustment was made to ADIT to account for the adjustments to pension, retiree medical, and FAS 112 expenses . Finally, an adjustment was made to the CTY to prorate the forecasted ADIT balances in compliance with IRS regulations. When using a CTY, a proration for the change in ADIT is required instead of the 13-month averaging method to avoid a potential violation of tax normalization rules. Details of the adjustments to ADIT balances are shown on Attachments APF-1 and APF-2, Schedule 115.

Q. HAS THE COMPANY INCLUDED ANY OTHER NEW RATE BASE ITEMS IN THE COST OF SERVICE PRESENTED IN THIS RATE CASE?

A. No.

G. <u>Cash Working Capital</u>

Q. PLEASE DESCRIBE CASH WORKING CAPITAL INCLUDED IN RATE BASE.

A. Cash working capital is the amount of investor-supplied capital necessary to finance cost of service expenses between the time the expenditures are required to provide the service to customers and the time cash is received for that service. To determine the allowance of cash working capital, the Commission has traditionally accepted the use of a lead-lag study.

Q. HAS THE COMPANY CALCULATED CASH WORKING CAPITAL IN THIS RATE CASE IN THE SAME MANNER AS IN PRIOR CASES?

A. Yes.

Q. DID THE COMPANY PERFORM A LEAD-LAG STUDY TO DERIVE THE CASH WORKING CAPITAL AMOUNT IN RATE BASE IN THIS RATE CASE?

A. Yes. The Company prepared a lead-lag study based on the 12 months ending June 30, 2021, which was used for the CTY and the 2021 HTY presented in this rate case. The lead-lag study is presented in two Attachments: (1) Attachment APF-10 is a summary of the lead-lag study for all components; and (2) Attachment APF-11 is the detail supporting the study.

Q. PLEASE DESCRIBE A LEAD-LAG STUDY.

A. A lead-lag study is a method used to measure the amount of working capital required to finance a utility's day-to-day operations. There are two parts in a lead-lag study. First, the expense lead must be calculated. An extensive and detailed study of the payment practices for each cash expense is made by measuring the period of time from when the Company receives goods or services ("the service period") and the date the expense is paid. Statistical sampling can be used to determine the expense lead. Once the expenses to be reviewed (census group or sample) have been determined, each invoice is reviewed to determine the service period. The service period's mid-point date is calculated. Using the check date as the payment date, the mid-point is subtracted from the payment date, resulting in the number of lead days. Second, the revenue lag must be calculated. The revenue lag is the time between the mid-point of the service period to the date when the Company receives payment from its customer. Depending on the number of customers, statistical sampling can be used to determine the revenue lag.

The expense lead is then subtracted from the revenue lag to determine the number of days until the Company is compensated for its expense payout. This net number of days is converted to an annual number by dividing by 365 days, which is referred to as the cash working capital factor. The cash working capital factor is multiplied by the corresponding test period expense items and then added to rate base. Cash working capital factors can be positive or negative, depending upon whether the expense lead is shorter or longer than the revenue lag.

Q. WHAT STATISTICAL SAMPLING METHODOLOGY DID THE COMPANY USE IN THE LEAD-LAG STUDY PERFORMED IN THIS RATE CASE?

A. The Company used the same statistical sampling method to calculate the lead-lag study in this rate case as was used in the electric rate case in Proceeding No. 06S-234EG, which both Staff and the Colorado Office of Consumer Counsel ("OCC") agreed would be used in future studies.

<u>Revenue lag parameters</u>

- Confidence level: 95 percent
- Precision: 5 percent
- Proxy mean and variance: mean and variance from the 2017 electric lead-lag study as a starting point for the sample size calculation.
- For sampled data sets: any accounts drawn with records for fewer than eleven months will be discarded and a new account drawn from the sample.
- For census or population data sets: all accounts will be used, regardless of the number of records within each account.
- Sample size: consistent with the preceding two parameters, an increase in sample size of no less than 50 percent is required in order to achieve the confidence and precision requirement as stated above, to compensate for incomplete data, incomplete records, and possible distortion in sample size due to use of mean and variance from the 2017 electric lead-lag study as a proxy mean and variance in this study.
- Sampling: draw without replacement.

Expense lead parameters

- Confidence level: 90 percent
- Precision: 10 percent
- Proxy mean and variance: mean and variance from the 2017 electric lead-lag study for coal, gas for other production, purchased power, and other non-labor O&M expense as a starting point for sample size calculation.
- Sample size: consistent with the preceding two parameters, an increase in sample size of no less than 20 percent is required in order to achieve confidence and precision requirement as stated above, to compensate for incomplete data, incomplete records, and possible distortion in sample size due to use of mean and variance results from the most recent lead-lag study information as a proxy mean and variance in this study.
- Stratified sampling/probability proportional to size ("PPS") sampling: acceptable.
- Sampling: draw without replacement.

Q. WHAT PROCESS DOES THE COMPANY FOLLOW WHEN PREPARING A LEAD-LAG STUDY FOR A RATE CASE FILING?

A. The process used to prepare a lead-lag study for a rate case filing is presented in Attachment APF-11.

Q. WHAT CASH EXPENSE ITEMS ARE INCLUDED IN THE EXPENSE LEAD CALCULATION?

A. The following cash expense items have historically been included in the expense lead calculation, and were included in the study prepared for this rate case:

- Natural gas purchased for resale;
- Labor O&M expense;
- Non-Labor O&M expense;
- XES charges booked to O&M expense;
- Incentive pay;
- Paid time off;
- Taxes other than income taxes (e.g., property tax and payroll taxes);
- State income taxes;
- Federal income taxes;
- Franchise fees paid; and
- Sales taxes paid.

Q. DID THE COMPANY INCLUDE INTEREST ON LONG-TERM DEBT IN THE EXPENSE LEAD CALCULATION?

A. No. Interest on long-term debt is not included in the lead-lag study. The Commission has determined in several previous Public Service rate cases that interest on long-term debt should not be included as a component in the cash working capital allowance, including the 2020 Gas Combined Rate case.[7]

Q. BRIEFLY EXPLAIN THE PROCEDURES USED TO DETERMINE THE EXPENSE LEAD.

A. The Company used statistical sampling to determine the expense lead for the non-labor O&M cash working capital expense category. The expense population for this category was limited to invoices pertaining to either the gas or common utility, and excluded thermal and electric utility invoices. One hundred percent of the invoices and payments were reviewed and service dates gathered for the Gas for Resale, O&M Labor, and the various tax cash working capital expense categories. The expense lead is the average number of days from the time of service to the date the Company remits payment for the service to the vendor. The expense lead for each invoice is determined by taking the sum of the following periods:

1) The service period, based on the mid-point of each invoice's service period;
2) The payment period, based on the number of days it takes for the Company to remit payment to the vendor from the mid-point date of each invoice's service period; and
3) A half day is added to bring the payment date to noon of that day. The expense lead days are weighted by the amount of the invoices.

[7] In the recent 2019 Electric Phase I and the 2020 Gas Combined Rate Case, Proceeding No. 20AL-0049G, long-term debt interest was not included in cash working capital. No parties opposed this treatment.

Q. HOW DID THE COMPANY CALCULATE THE CASH WORKING CAPITAL ASSOCIATED WITH THE COSTS OF GAS PURCHASED FOR RESALE COSTS?

A. The Company multiplied the applicable net lead-lag factors by the per book HTY gas purchased for resale expense amount. Currently, the Gas Department has no gas costs in base rates, as all gas costs are recovered through the GCA. Therefore, using per book expense is most representative for calculating a cash working capital amount.

Q. PLEASE DESCRIBE HOW THE EXPENSE LEAD WAS CALCULATED FOR THE CASH WORKING CAPITAL ITEM RELATING TO THE XES CHARGES TO PUBLIC SERVICE.

A. The Company has calculated the cash working capital expense lead for billings from XES to Public Service using the same methodology that has been used in its last several rate cases. XES provides administrative, accounting and legal services to Public Service and other Xcel Energy subsidiaries. The Company pays XES on approximately the 23rd day of the month following the month in which the services were rendered. The expense lead is calculated by adding the service period (the mid-point of each month's service period) to the payment period (the number of days it takes for the Company to remit payment to XES).

Q. PLEASE DESCRIBE THE CASH WORKING CAPITAL ALLOWANCE THAT IS ADDED TO RATE BASE TO REIMBURSE XES FOR FINANCING THE PUBLIC SERVICE CHARGES.

A. Consistent with the methodology that has been used in its last several rate cases, the Company has calculated a cash working capital factor that is applied to the XES charges to account for the financing costs incurred by XES before they are paid for the services rendered. The revenue lag is the number of days it takes for Public Service to pay for services rendered. The expense lead is the same as those used by Public Service, since both companies have the same accounts payable payment practices.

Q. BRIEFLY EXPLAIN THE PROCEDURES USED TO DETERMINE THE REVENUE LAG.

A. The revenue lag was calculated using data from the Company's customer billing system. The Company used statistical sampling for the customers billed under the RG and CSG rate schedules due to the large number of customers, and used 100 percent sampling for all other rate schedules. The revenue lag was calculated for each invoice. The revenue lag is the average number of days from the time of service to the date the Company receives payment from the customer. The revenue lag is determined by taking the sum of the following periods:

1) The meter-reading period, based on the mid-point of each month's service period;

2) The collection lag, based on the number of days it takes for the customers to pay their bills from the mid-point date of the service period; and

3) An additional half day is added to account for the posting of the customer receipts to the Company's bank account. An average lag day value for each rate schedule was calculated and weighted with the percent of total revenue.

For residential customers, a 30-day limit on lag days was instituted in order to exclude the effects of late payments.

Q. WHAT ARE THE RESULTING LEAD-LAG FACTORS THE COMPANY HAS CALCULATED FOR USE IN DETERMINING CASH WORKING CAPITAL IN THIS RATE CASE?

A. The resulting lead-lag factors are presented on Attachment APF-11. These cash working capital factors were then weighted by the applicable test period costs to calculate Cash Working Capital, as presented on Attachments APF-1 and APF-2, Schedule 103.

VI. REVENUE

A. Base Revenue

Q. PLEASE DESCRIBE HOW PRESENT BASE RATE REVENUE FOR THE CTY WAS DEVELOPED FOR THIS CASE.

A. Company witness Ms. Jannell Marks presents the Sales Forecast (customers and consumption) that was used to develop Retail Base Revenue. The base rate revenue used in the cost of service was calculated using the test period number of customers and therm sales, by rate schedule, from the customer and sales forecast that Ms. Marks is sponsoring. The residential and commercial gas lighting billing units (mantle fixtures) and the firm, interruptible, and transportation service demand capacity billing units were all based on historical levels.

The billing units were then multiplied by the settled Phase II base rates, approved in Proceeding No. 19AL-0309G. The derivation of present base rate revenue is shown on Confidential Attachment APF-1A. Retail present base rate revenue for the 2022 CTY is $610,512,984.

Q. PLEASE DESCRIBE HOW PRESENT BASE RATE REVENUE FOR THE 2021 HTY WAS DEVELOPED FOR THIS RATE CASE.

A. As I have previously indicated, the HTY is being filed solely for informational, comparative purposes. The present base rate revenue used in the 2021 HTY cost of service was calculated using the amount the test period number of customers, sales and billing demand by rate schedule. The Company made two adjustments to the test period billing units. First, as discussed in the Direct Testimony of Ms. Marks, the Company has normalized the energy sales and demand based on the weather normalization approved in the 2020 Gas Combined Rate Case, a 10-year average including the test year period. Second, the Company made an adjustment to annualize customers at the year-end level consistent with using year-end rate base.

The resulting billing units after applying these adjustments were then multiplied by current tariffed base rates. The current S&F rate includes an amount for the GAP. Those revenues are not included in base rate revenue and have been recorded as a regulatory liability to fund that program.

Q. PLEASE DESCRIBE THE COMPANY'S ADJUSTMENT TO ANNUALIZE CUSTOMERS AT THE YEAR-END LEVEL FOR THE 2021 HTY.

A. The Company is presenting the 2021 HTY using year-end rate base and annualized depreciation expense. The annualization adjustment to the 2021 HTY base revenue reflects the projected revenue of new residential, commercial & industrial, and transportation customers that have been added to the Company's gas system that were not on the system during all of the year ended June 30, 2021, but who are expected to be served after the 2021 HTY. This adjustment results in the addition of $3,333,204 of revenue to the 2021 HTY and thus reduces the deficiency by the same amount, as shown on Attachment APF-2A_C and Attachment APF-2A.

Q. PLEASE DESCRIBE THE CALCULATION OF THE ADJUSTMENT TO ANNUALIZE CUSTOMER REVENUE.

A. First, we calculated the change in customers from the beginning of the 2021 HTY to the end of the 2021 HTY. Results of this calculation shows that residential customer counts have grown by 7,925 customers, commercial & industrial customer counts have grown by 259 and transportation customer counts are expected to grow by 3 customers .

Next, we calculated the revenue adjustment necessary to annualize the revenues of these new customers. Public Service assumed that the base revenue for each additional customer was equal to the average base revenue per customer during the entire 2021 HTY. This approach resulted in total adjusted base rate revenue increase of $3,333,204 of which $2,358,652 was for residential customers, $964,347 for commercial & industrial customers and $10,205 for transportation customers.

Q. HOW DOES THE YEAR-END CUSTOMER ANNUALIZATION ADJUSTMENT BENEFIT CUSTOMERS?

A. The adjustment to annualize customers at the year-end level increases the 2021 HTY revenue, as noted above, and reduces the overall revenue deficiency. The resulting level of base revenue is more representative of when rates will be in effect from this case. This adjustment is also consistent with the year-end rate base methodology in this case. If a 13-month average rate base methodology is employed, no adjustment should be made to annualize customers at the year-end level.

B. Other Revenue Adjustments

Q. PLEASE DESCRIBE THE OTHER REVENUES THAT ARE INCLUDED AS A REDUCTION TO THE CTY COST OF SERVICE STUDY PRESENTED IN THIS RATE CASE.

A. The following other revenues accounts are included in the CTY presented in this rate case, including: FERC Account 487, Late Payment Revenue; FERC Account 488, Miscellaneous Service Revenue; FERC Account 490, Production Extraction Revenue; FERC Account 493, Rent from Gas Property, and FERC Account 495, Other Gas Revenue. The Company used the 2022 budgeted other revenue for the CTY cost of service and the actual other revenue for the 12 months ended June 30, 2021 for the 2021 HTY cost of service.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO OTHER REVENUE CONSISTENT WITH PREVIOUS RATE CASES?

A. Several adjustments were made to other revenue, which are similar to those made in previous rate cases, including the following:

- Elimination of other revenue amounts not included in retail base rates (i.e., rate refunds, DSM incentives, and deferred PSIA costs);
- Elimination of residential late payment revenues; and
- Elimination of other revenue amounts recorded in the cost of service that are not certain going forward or are not recoverable from retail customers (i.e., bad debt concessions, and gas transportation penalties);

The adjustments to other revenue are shown on Attachments APF-1 and APF-2, Schedule 211.

Q. PLEASE DESCRIBE THE COMPANY'S TREATMENT OF RESIDENTIAL LATE PAYMENT REVENUE.

A. The Company has eliminated the residential late payment revenue billed to customers in the cost of service studies presented in this case, as shown on Attachments APF-1 And APF-2, Schedule 211. The Company proposes to eliminate this revenue credit and continue the donation to Energy Outreach Colorado, consistent with the treatment of residential late payment revenue the Commission approved in the Company's last electric rate case.

Q. DID YOU MAKE ANY NEW ADJUSTMENTS TO OTHER REVENUE IN THIS CASE?

A. Yes. As discussed by Company witness Mr. N. Mason Harrison, the Company is proposing to increase the rates it charges under its Charges for Rendering Services Tariff relating to instituting new service. The revenues billed for instituting new service are recorded in FERC Account 488, Miscellaneous Service Revenue. The new proposed rates will increase the revenue credits reflected in the cost of service. The adjustment to reflect the new proposed rates for instituting new service is shown on Attachments APF-1 and APF-2, Schedule 211.

VII. EXPENSES

Q. PLEASE DISCUSS GENERALLY THE O&M EXPENSES AND OTHER INCOME STATEMENT ITEMS INCLUDED IN THE CTY.

A. Public Service's CTY in this rate case ending on December 31, 2022, is based on historical O&M costs for the 12 months ending June 30, 2021. As previously mentioned, when using an HTY, the Commission has allowed known and measurable adjustments one year past the end of the test year. Consistent with this principle, the Company made pro forma adjustments in the 2021 HTY for known and measurable O&M changes through June 30, 2022 to arrive at the fully adjusted 2021 HTY. The fully adjusted 2021 HTY O&M expenses are then adjusted for forecasted changes in specific areas, as a reasonable proxy for 2022 forecasted O&M for the CTY. In the sections below, I discuss in more detail the expenses and expense adjustments included in the CTY.

Q. PLEASE DISCUSS THE O&M EXPENSES AND OTHER INCOME STATEMENT ITEMS INCLUED IN THE 2021 HTY.

A. The 2021 HTY is based on actual O&M expenses with certain known and measurable adjustments through June 30, 2022 as noted above. In the sections below, I discuss in more detail the expenses and expense adjustments included in the 2021 HTY. The 2021 HTY itself is presented solely for informational, comparative purposes.

A. <u>Labor and Labor-Related Expenses</u>

Q. PLEASE DISCUSS THE ADJUSTMENTS TO INCLUDE WAGE INCREASES IN THE CTY PRESENTED IN THIS RATE CASE.

A. As addressed earlier in my testimony, the Company started with the actual labor O&M expenses for the 12 months ended June 30, 2021 and adjusted to the CTY level. Specifically, we took actual labor expense amounts for the twelve months ending June 30, 2021 and made adjustments to better reflect labor O&M for the period rates will be in effect.

As discussed by Company witness Mr. Knoll, non-bargaining unit employee wage increases are effective March each year. An adjustment is needed to reflect the average increase of 3.00 percent effective March 2021 for the entire period July 2020 through June 2021 ("2020 adjusted labor"). Added to the 2020 adjusted labor is an adjustment to reflect the average increase of 3.00 percent for the wage increase effective March 2021 for the period July 2021 through June 2022 ("2021 adjusted labor"). Finally, we added a 3.0 percent increase to the 2021 adjusted labor for the wage increase effective March 2022 for the period July 2022 through December 2022.

For bargaining unit employees, as discussed by Company witness Mr. Knoll, wage increases are effective June each year. Like the adjustments made for the non-bargaining wage increases, I have made an adjustment to reflect the bargaining unit wage increase of 2.80 percent effective June 2020, plus an adjustment for the wage increase of 2.80 percent effective June 2021. Finally, we made an adjustment to add a 2.80 percent increase to the 2021 labor for the wage increase effective June 2022. I have calculated an average percentage increase to apply to the per book labor amounts to reflect the increases discussed above, as shown below in Table APF-D-5:

Table APF-D-5

CTY	Number of months to Escalate	Annual Rate	Rate/Month	Compound per Year	Compound Rate Total
Non-Bargaining					
Jul 2020-Jun 2021	8	3.00%	2.00%		2.00%
Jul 2021-Jun 2022	12	3.00%	3.00%	0.06%	3.06%
Jul 2022-Dec 2022	6	3.00%	1.50%	0.05%	1.55%
Total Non-Bargaining					**6.61%**
Bargaining Unit					
Jul 2020-Jun 2021	11	2.80%	2.57%		2.57%
Jul 2021-Jun 2022	12	2.80%	2.80%	0.07%	2.87%
Jul 2022-Dec 2022	6	2.80%	1.40%	0.04%	1.44%
Total Bargaining Unit					**6.88%**

For the non-bargaining unit labor, the total percentage increase is 6.61 percent over the two and a half years, and for the bargaining unit labor, the total percentage increase is 6.88 percent over the two and a half years, as shown on Attachment APF-1, Schedule 248. In addition, Taxes Other Than Income Taxes was adjusted for the related payroll taxes from these wage increases.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO INCLUDE WAGE INCREASES IN THE 2021 HTY.

A. For the 2021 HTY, the adjusted labor O&M expense was adjusted for known and measurable cost increases that the Company has paid or is expected to pay through June 30, 2022, a full year after the end of the 2021 HTY, consistent with past Commission recognition of making known and measurable adjustments. I applied the same wage increases as previously discussed for non-bargaining and bargaining unit labor through 2022. I have calculated an average percentage increase to apply to the per book labor amounts to reflect the increases as shown below in Table APF-D-6:

Table APF-D-6

2021 HTY	Number of months to Escalate	Annual Rate	Rate/Month	Compound per Year	Compound Rate Total
Non-Bargaining					
Jul 2020-Jun 2021	8	3.00%	2.00%		2.00%
Jul 2021-Jun 2022	12	3.00%	3.00%	0.06%	3.06%
Total Non-Bargaining					**5.06%**
Bargaining Unit					
Jul 2020-Jun 2021	11	2.80%	2.57%		2.57%
Jul 2021-Jun 2022	12	2.80%	2.80%	0.07%	2.87%
Total Bargaining Unit					**5.44%**

For the non-bargaining unit labor, the total percentage increase over the two years is 5.06 percent, and for the bargaining unit labor, the total percentage increase is 5.44 percent over the two years, as shown on Attachment APF-2, Schedule 248. In addition, Taxes Other Than Income Taxes was adjusted for the related payroll taxes from these wage increases.

Q. DID THE COMPANY CONSIDER PRODUCTIVITY GAINS WHEN MAKING THE WAGE ADJUSTMENTS TO THE CTY AND 2021 HTY?

A. Yes. The Company prepared a productivity study consistent with the productivity study filed and approved by the Commission in the 2020 Combined Gas Phase Rate Case, which was modeled after the productivity study approved in the

Company's 1993 rate case, in Decision No. C93-1346, adopted October 14, 1993, in Proceeding No. 93S-001EG.[8] The productivity study is a measure of the average of compound growth rates of output per unit of labor from 2011 through 2020, as shown in Attachment APF-12.

Q. PLEASE DESCRIBE THE METHODOLOGY USED TO DEVELOP THE LABOR PRODUCTIVITY INFORMATION PROVIDED IN ATTACHMENT APF-14.

A. The general definition of labor productivity is the ratio of output to input. It is the relationship between the quantity and value of goods and services produced (output) and the quantity of labor required (the input). The output used was gas sales, normalized for weather. The input used was total gas labor costs as reported in the Company's FERC Form No. 1, plus gas employee benefits expense. The result is negative productivity, due to sales declining over the 10-year period of time that was used for this analysis. Consequently, there is no productivity offset to the out-of-period wage adjustment based on 10 years of information using the methodology approved by the Commission.

[8] The Company filed to include an out-of-period wage adjustment with a productivity offset in two subsequent gas rate cases in Proceeding No. 96S-290G ("1996 Rate Case") and Proceeding No. 98S-518G ("1998 Rate Case"). In the 1996 Rate Case, the Commission did not approve the Company's productivity factor, or the productivity factor advocated by the OCC. *See* Decision No. C97-118, adopted January 27, 1997. In the 1998 Rate Case, the Commission rejected the Company's productivity factors, accepted a productivity factor that removed the out-of-period wage adjustment in total. *See* Decision No. C99-579, adopted May 29, 1999.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO THE ANNUAL EMPLOYEE INCENTIVE COMPENSATION THAT THE COMPANY HAS INCLUDED IN THE COST OF SERVICE STUDY PRESENTED IN THIS RATE CASE.

A. The Company makes employee incentive payments above base salaries so long as certain minimum earnings performance targets are met and other pre-established key performance indicators are met or exceeded, referred to as the AIP. I made two adjustments to incentive pay in the cost of service studies presented in this rate case, consistent with the testimony of Mr. Michael Knoll.

First, I started with the per book incentive pay for the 12 months ended December 31, 2020, and made an adjustment to limit incentive pay to 100 percent of target for both Public Service and XES employees. Second, I made an adjustment for the 2021 non-bargaining unit wage, to increase incentive pay by 2.00 percent to reflect incentive pay at target, at the June 2021 level of costs, as shown on Attachment APF-2, Schedule 247. Finally, I made an adjustment for the 2021 non-bargaining unit, to increase the incentive pay by another 3.06 percent to reflect incentive pay at target, at the June 2022 level of costs as shown on Attachment APF-1, Schedule 247. The incentive amounts that have been removed from the cost of service studies presented in this rate case are actual costs that have been paid to employees by the Company pursuant to the compensation plans described by Company witness Mr. Knoll.

In addition, Taxes Other Than Income Taxes was adjusted for the related payroll taxes, and the Cash Working Capital Allowance related to incentive pay reflects the adjusted Test Year levels.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE DISCRETIONARY INCENTIVE PAY.

A. Consistent with prior rate cases, the Company has excluded discretionary incentive pay from the cost of service studies presented in this case. As the name implies, discretionary incentive pay is not always paid to employees each year, it is discretionary. Therefore, these costs have been excluded from this case, as shown on Attachments APF-1 and APF-2, Schedule 278. In addition, as with the other adjustments to employee labor expenses, adjustments were made to Taxes Other Than Income Taxes for the related payroll taxes.

Q. PLEASE DISCUSS THE ADJUSTMENT TO LONG-TERM INCENTIVE COMPENSATION.

A. The Company has excluded the long-term portion of the executives and non-executive management employees' incentive compensation from the cost of service studies presented in this rate case, net of the portion that is attributable to environmental goals and the time-based component, as discussed by Company witness Mr. Knoll. Adjustments have been made to eliminate these costs from FERC Account 920, Administrative and General Salaries, in the CTY and the 2021 HTY. Specifically, adjustments were made to the CTY to eliminate all the long-term incentive compensation in the amount of $4,228,075, as shown on Attachment APF-, Schedule 239. Then an adjustment was made to include the portion of long-term incentive compensation that is attributable to the time-based component, as shown on Attachment APF-1, Schedule 241. In addition, as discussed by Company witness Mr. Knoll, the Company is requesting recovery of the environmental goals of long-term incentive compensation, as shown on Attachments APF-1 and APF-2, Schedule 240. The result is a net elimination of $2,912,682 in costs. In addition, as with the other adjustments to employee labor expenses, adjustments were made to Taxes Other Than Income Taxes for the related payroll taxes and the Cash Working Capital Allowance factor was adjusted. Similar adjustments were made to the 2021 HTY, as shown on Attachment APF-2, Schedules 240 and 241.

Q. WHAT ACCOUNTS IN THE COST OF SERVICE STUDY ARE SUBJECT TO THIS APPROACH TO ADDRESSING LABOR AND LABOR-RELATED EXPENSES?

A. The list below identifies adjustments made to include wage increases for the bargaining unit employees and non-bargaining unit employees. These adjustments are shown on Attachments APF-1 and APF-2, Schedule 248.

- Other gas supply O&M expense;
- Underground storage O&M expense;
- Production operations O&M expense;
- Transmission O&M expense;
- Distribution O&M expense;
- Customer operations expense; and
- Administrative and general ("A&G") expense.

B. Cost of Gas Purchased for Resale

Q. PLEASE DISCUSS THE ADJUSTMENTS TO FUEL AND PURCHASED POWER COSTS.

A. The cost of gas purchased for resale was removed from base rates in a previous Phase II gas rate case, Proceeding No. 99S-609G. These costs are now included in the GCA. Therefore, the costs of gas purchased for resale costs are set to zero in the cost of service study presented in this rate case.

C. Other Gas Supply And Underground Storage O&M Expense

Q. WHAT ADJUSTMENTS WERE MADE TO OTHER GAS SUPPLY O&M EXPENSES?

A. An adjustment was made to reclassify labor expenses recorded in FERC Account 807, Well Expenses – Purchased Gas as an O&M expense.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE LABOR EXPENSES FROM THE PURCHASED GAS ACCOUNT TO O&M EXPENSES.

A. The Company recorded labor expenses in FERC Account 807, which is a cost of gas purchased for resale expense account that would normally be eliminated because these costs are recovered through the GCA. However, labor expense costs are not recovered through the GCA, so these costs needed to be reclassified as Other Gas Supply expenses and recovered in base rates. The adjustment is shown on Attachments APF-1 and APF-2, Schedule 201.

D. Gas Extraction Operations

Q. DID YOU MAKE ANY ADJUSTMENTS TO GAS EXTRACTION OPERATIONS EXPENSES?

A. Yes. I eliminated the costs associated with managing the Company's mineral rights. The costs are not associated with gas mineral assets. They are related to the mineral rights held by the Electric Department but were inadvertently booked to a gas FERC account. The adjustment is shown on Attachments APF-1 and APF-2, Schedule 282.

E. Transmission O&M Expense Adjustments

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO TRANSMISSION O&M EXPENSE?

A. Adjustments were made to:

1) Eliminate the costs associated with the Front Range Pipeline; and
2) Include known and measurable expenses related to integrity management activities, as discussed in more detail by Company witness Ms. Gilliland.

Q. PLEASE DISCUSS THE FRONT RANGE PIPELINE ADJUSTMENTS .

A. In Decision No. C98-556, mailed June 4, 1998, in Proceeding No. 97A-622G, the Commission approved Public Service's application for a Certificate of Public Convenience and Necessity to construct the Front Range Pipeline, subject to conditions. As one condition, the Commission required that service over the Front Range Pipeline be provided on a separate, stand-alone basis instead of being accorded "rolled-in" rate treatment with Public Service's other services. In accordance with that determination, all costs associated with the Front Range

Pipeline are excluded from base rate revenue requirements. The Company made three adjustments to the Gas Department cost of service study associated with the Front Range Pipeline, including:

1) Eliminating the Test Year lease payments (FERC Account 860);
2) Eliminating O&M expenses (FERC Account 863); and
3) Eliminating property taxes (FERC Account 408).

All of these adjustments are shown on Attachments APF-1 and APF 2, Schedule 242. Through these three adjustments, the Company has excluded all costs associated with the Front Range Pipeline consistent with Decision No. C98-556.

Q. HOW DOES THE COST OF SERVICE STUDY REFLECT KNOWN AND MEASURABLE EXPENSE ADJUSTMENTS RELATED TO INTEGRITY MANAGEMENT ACTIVITIES?

A. A known and measurable adjustment was included in the cost of service to reflect costs associated with integrity management activities the Company expects to incur during the Test Year as discussed in more detail by Company witness Ms. Lauren Gilliland. The adjustment is shown on Attachments APF-1 and APF-2, Schedule 256.

F. Distribution O&M Expense Adjustments:

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO DISTRIBUTION O&M?

A. Adjustments were made to:

1) Include costs associated with the proposed change to the Company's Rendering Services Tariff relating to instituting new service as described by Mr. Harrison;

2) Include costs associated with the Damage Prevention program described by Company witness Ms. Gilliland; and

3) Include known and measurable expenses related to an out of period adjustment related to a software license discussed by Ms. Gilliland.

Q. PLEASE DESCRIBE THE ADJUSTMENT RELATED TO THE CHANGE IN THE RENDERING SERVICES TARIFF.

A. Mr. Harrison describes the adjustment but I increased distribution O&M to account for the change in the tariff. This adjustment is shown on Attachments APF-1 and APF-2 Schedule 1-249.

Q. PLEASE DESCRIBE THE PROPOSAL TO DEFER O&M COSTS ASSOCIATED WITH THE DAMAGE PREVENTION PROGRAM.

A. Ms. Gilliland testifies that the Company is proposing to continue deferral of O&M costs associated with the Damage Prevention program that are greater than or less than the amount in base rates, beginning with the rates effective from this rate case. During the HTY, the Company recorded credits to FERC Account 874 to reduce O&M expenses to the level of Damage Prevention approved in the Company's 2020 Gas Combined Rate Case. However, the Company spent more in Damage Prevention O&M expenses than the level set in the Company's 2020 Gas Combined Rate Case. An adjustment was made to the HTY to eliminate the credits, thereby reflecting the HTY level of Damage Prevention costs in this rate case. The Company has included $23,065,855 in Damage Prevention O&M expense in the HTY and CTY, as shown on Attachment LG-3 to Ms. Gilliland's Direct Testimony. The Company will address the recovery of any regulatory asset/liability that might arise after this rate case in its next gas rate case proceeding. I discuss the Company's amortization proposal related to the deferral of these costs from the Company's 2020 Gas Combined Rate Case later in my Direct Testimony.

Q. HOW DOES THE COST OF SERVICE STUDY REFLECT KNOWN AND MEASURABLE EXPENSE ADJUSTMENTS RELATED TO OUT OF PERIOD EXPENSES.

A. A known and measurable adjustment was made to Distribution O&M expense to reflect an out of period expense related to a software license the Company incurred, as discussed in more detail by Company witness Ms. Gilliland. The adjustment is shown on Attachment APF-1, Schedule 257.

G. <u>Customer Operations Expense Adjustments:</u>

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO CUSTOMER OPERATIONS EXPENSES?

A. Adjustments were made to:

1) Include interest expense on customer deposits; and
2) Eliminate the Gas DSM expenses.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE INTEREST EXPENSE ON CUSTOMER DEPOSITS.

A. As I previously discussed, the Company includes customer deposits as a reduction to rate base and is also allowed to include the related interest as an addition to Customer Operations expense. The customer deposit interest rate used in this rate case is 0.08 percent, which is the Commission approved rate effective January

1, 2022, as approved in Decision No. C21-0676, Proceeding No. 21M-0506G. The adjustment is shown on Attachments APF-1 and APF-2, Schedule 230.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE THE GAS DSM COSTS FROM THE COST OF SERVICE.

A. All costs associated with the Company's gas DSM program have been excluded from the cost of service in this case, since these costs are currently recovered through the gas DSMCA. An adjustment has been made to eliminate the amount of gas DSM costs booked in the Test Year from Customer Operations expense, FERC Account 908, as shown on Attachments APF-1 and APF-2, Schedule 222.

H. <u>Administrative and General Expense Adjustments:</u>

Q. WHAT ADJUSTMENTS HAVE YOU MADE TO A&G EXPENSES?

A. Adjustments were made to:

1) Eliminate a majority of the Company's aviation expenses;
2) Eliminate certain employee expenses;
3) Adjust the level of pension and benefits expenses;
4) Eliminate the pension expense amount that was deferred in the HTY above the pension expense baseline;
5) Adjust active healthcare expense for claims incurred-but-not-reported;
6) Adjust retiree medical expenses to zero out the negative expenses;
7) Adjust the regulatory Commission expense for the Commission's current level of assessment fees;
8) Eliminate the amortization of rate case expenses from the 2020 Gas Combined Rate Case;
9) Include the incremental costs for preparing and litigating this rate case and other cases that have been deferred;

10) Eliminate 50 percent of Investor Relations expenses; and

11) Eliminate certain advertising expenses.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE CERTAIN AVIATION EXPENSES ASSOCIATED WITH THE CORPORATE AIRCRAFT.

A. The Company is proposing to recover 8.55 percent of the costs associated with the corporate aircraft in base rates. An adjustment was made to eliminate 91.45 percent of the corporate aircraft costs totaling ($301,189) and shown on Attachment APF-1, Schedule 224. The adjustment to eliminate a majority of corporate aircraft costs is based on a study of the Company's corporate aircraft usage between Xcel Energy's corporate headquarters in Minneapolis, Minnesota and the other Xcel Energy Operating Company headquarters in Denver, Colorado and Amarillo, Texas. The corporate aircraft costs were compared to equivalent commercial aircraft costs to determine the percentage eliminated. Some aviation expenses are recorded as labor expenses in the Company accounting system. Therefore, as with the other adjustments to employee labor expenses, adjustments also were made to Taxes Other Than Income Taxes for the related payroll taxes. A similar adjustment was made to the 2021 HTY as shown on Attachment APF-2, Schedule 224.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE CERTAIN EMPLOYEE EXPENSES.

A. In prior rate cases, the Company had reviewed actual test year accounting transactions to identify any costs that did not meet travel policy guidelines, and then made adjustments to remove a portion of employee expenses that were incorrectly recorded to operating accounts. Due to limited employee travel in 2020 and 2021 because of COVID-19, the Company has not reviewed the actual HTY accounting transactions in this case. However, the Company is still proposing to make an adjustment to employee expenses to eliminate a portion of costs that do not meet travel policy guidelines. The Company proposes to use the same percentages of employee expenses that were eliminated in the 2020 Gas Combined Rate Case, by employee expense category applied to the 2021 HTY employee expenses. The adjustments are shown on Attachments APF-1 and APF-2, Schedule 227.

Q. PLEASE DISCUSS THE LEVEL OF PENSION AND BENEFITS EXPENSE INCLUDED IN THE 2022 CTY.

A. As discussed by Company witness Mr. Schrubbe, the qualified pension and non-qualified pension expense, active healthcare expense and other employee benefit expenses at the 2022 level are included in the CTY presented in this rate case, and the 2021 level of expense is included in the 2021 HTY. The pension and benefits adjustments are shown on Attachments APF-1 and APF-2, Schedule 233. Included in the adjustments to pension and benefits expense is an adjustment to zero out the negative retiree medical expenses in the 2021 HTY. This is consistent with prior rate cases. As discussed by Ms. Marci McKoane, the Company is proposing to continue to use a pension expense tracker, in which the retail pension costs in the CTY will set the level of pension expenses for the deferral. The amount of the CTY retail pension expenses are $5,226,897, are shown below in Table APF-D-7.

Table APF-D-7

	Total Electric	Retail Allocator	CPUC Amount
Qualified Pension	$4,966,723	99.97%	$4,965,233
Non-Qualified Pension	$261,743	99.97%	$261,664
Total	$5,228,466		$5,226,897

Pension expenses incurred beginning with the effective date of rates in this rate case, expected November 1, 2022 that are greater or lower than the CTY level will be deferred in a regulatory asset/liability account, and any regulatory asset/liability would be recovered in a future rate case.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO PENSION AND BENEFITS EXPENSE ASSOCIATED WITH AMORTIZATION OF THE QUALIFIED AND NON-QUALIFIED PENSION EXPENSES APPROVED IN THE 2020 GAS PHASE I.

A. In the 2020 Combined Gas Rate Case, the Commission authorized the Company to amortize the regulatory assets associated with the qualified and non-qualified pension expenses over three (3) years beginning with the effective date of rates, November 1, 2020. The amortization of the qualified and non-qualified pension expenses is included in A&G expense, FERC Account 926, Employee Pension and Benefits expense. As discussed later in my Direct Testimony, at the effective date of rates from this case, expected November 1, 2022, this regulatory asset will not be fully amortized. To ensure the Company does not recover more than authorized, the Company proposes to eliminate the amortization expense recorded in 2020 and 2021 and amortize the unamortized balances at November 1, 2022 over a new amortization period equal to 36 months. The adjustments to eliminate the amortization expense recorded in 2020 and 2021 are shown on Attachments APF-1 and APF-2, Schedule 279.

Q. PLEASE DISCUSS THE ADJUSTMENT TO PENSION AND BENEFITS EXPENSE TO ELIMINATE THE AMOUNT DEFERRED IN THE 2021 HTY ABOVE THE PENSION EXPENSE BASELINE ESTABLISHED IN THE 2020 COMBINED GAS RATE CASE.

A. An adjustment was made to eliminate the pension expense amount that was deferred in the 2021 HTY above the pension expense baseline established in the 2020 Gas Combined Rate Case, in order to reflect the current level of pension expense in this rate case, as discussed by Company witness Mr. Schrubbe. In addition, the Company is proposing to amortize the deferred pension expenses in this rate case as discussed later in my Direct Testimony. The adjustment to eliminate the pension expense that was deferred is shown on Attachments APF-1 and APF-2, Schedule 279.

Q. PLEASE DISCUSS THE ADJUSTMENT RELATED TO ACTIVE HEALTHCARE CLAIMS INCURRED-BUT-NOT-REPORTED.

A. As discussed by Company witness Mr. Schrubbe, the actual amount booked in the 2021 HTY for active healthcare expense is an estimate. Claims that are incurred in the 2021 HTY but not reported until after the books close should be adjusted. This adjustment in the amount of $780,463 is a decrease to FERC Account 926, Employee Pensions and Benefits expense as shown on Attachments APF-1 and APF-2, Schedule 228.

Q. PLEASE DISCUSS THE ADJUSTMENT TO EMPLOYEE PENSION AND BENEFIT EXPENSES RELATED TO RETIREE MEDICAL EXPENSES.

A. As discussed by Mr. Schrubbe, the Company recorded negative retiree medical expenses in the HTY. The Company is proposing an adjustment similar to what was approved in the 2020 Gas Combined Rate Case, to zero out the negative expense, in other words increase expense, and lower the prepaid balance, as shown on Attachments APF-1 and APF-2, Schedule 233.

Q. PLEASE DISCUSS THE ADJUSTMENT RELATED TO THE ADMINISTRATION FEES PAID TO THE COMMISSION.

A. The Company made an adjustment to FERC Account 928, Regulatory Commission Expense to reflect the expected Commission Administration Fees allocated to the Gas Department for fiscal year July 1, 2021 through June 30, 2022. The adjustments are shown on Attachments APF-1 and APF-2, Schedule 229. As discussed by Company witness Ms. McKoane, the Company is proposing a tracker in this case, in which the Commission regulatory fees allocated to the Gas Department in the CTY will set the level of expenses for the deferral. The Commission regulatory fees allocated to the Gas Department in the CTY are $3,913,433. Commission regulatory fees allocated to the Gas Department incurred beginning with the effective date of rates in this rate case, expected November 1, 2022 that are greater or lower than the CTY level will be deferred in a regulatory asset/liability account, and any regulatory asset/liability would be recovered in a future rate case.

Q. PLEASE DISCUSS THE ADJUSTMENT TO REGULATORY COMMISSION EXPENSES TO ELIMINATE THE AMORTIZATION OF 2020 GAS COMBINED RATE CASE EXPENSES.

A. In the 2020 Gas Combined Rate Case, the Commission approved an amortization of rate case expenses over three (3) years beginning with the effective date of rates from that case, November 1, 2020. An adjustment was made to FERC Account 928, Regulatory Commission expense, to eliminate the amortization of the 2020 Gas Combined Rate Case expenses recorded in the 2021 HTY. This adjustment ensures the Company will not over recover the 2020 Gas Combined Rate Case regulatory expenses by continuing to include this amortization in base rates. As discussed below, the Company is proposing to recover the unamortized amount over a new amortization period in this case. The adjustment is shown on Attachments APF-1 and APF-2, Schedule 279.

Q. IS THE COMPANY PROPOSING TO RECOVER THE UNAMORTIZED RATE CASE EXPENSES FROM THE 2020 GAS COMBINED RATE CASE?

A. Yes. As previously mentioned, the rate case expenses from the 2020 Gas Combined Rate Case are being amortized over a three (3) year amortization period that expires in October 2023, after the effective date of rates from this case. The Company proposes to add the unamortized amounts (from November 1, 2022 through October 2023) to the regulatory asset balances included in this case and amortize the remaining amount over a new period proposed in this case. The Company proposes to amortize these remaining amounts over three (3) years, consistent with the other regulatory amortizations proposed in this case. However, if the Commission were to adopt an HTY for this proceeding the Company would request an 18-month deferral as proposed by Ms. McKoane.

Q. PLEASE DESCRIBE THE ADJUSTMENT FOR COSTS EXPECTED TO BE INCURRED FOR THIS PROCEEDING.

A. As discussed by Company witness Ms. McKoane, Public Service has estimated the cost to file and process this case. The Company is proposing to amortize the total of these costs over three years, effective with the base rates in this rate case. In general, the amortization period should reflect the amount of time the Company expects between rate cases. If there are any unamortized balances, before the rates from the next gas rate case are effective, the Company will amortize the remaining amount over a new period in the next case. The adjustments to Regulatory Commission expense for rate case expenses are shown on Attachments APF-1 and APF-2, Schedule 238.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INVESTOR RELATIONS EXPENSES.

A. Consistent with the Commission's order in the 2020 Gas Combined Rate Case, the Company has eliminated 50 percent of the investor relations expenses in this rate case. The adjustments to A&G expenses are shown on Attachments APF-1 and APF-2, Schedule 268. Adjustments have also been made to payroll tax expenses related to the labor adjustments.

Q. WHAT ADVERTISING COSTS WERE ELIMINATED?

A. Consistent with prior Commission rulings, advertising expenses related to brand or promotional advertising booked in FERC Account 930.1, A&G General

Advertising expense, in the amount of $688,148 have been eliminated, as shown on Attachments APF-1 and APF-2, Schedule 237.

I. Depreciation Expense Adjustments

Q. PLEASE DISCUSS THE BASIS FOR THE DEPRECIATION EXPENSE PRESENTED IN THIS CASE.

A. The unadjusted depreciation and amortization expense presented in the CTY is based on the 2022 forecasted plant balances using the depreciation and amortization rates approved in the 2020 Gas Combined Rate Case. As discussed by Company witness Ms. Wold, an adjustment was made to common plant in the CTY to reflect the 2022 forecasted plant balances using the depreciation and amortization rate for common plant proposed in Docket No. 21AL-0317E.

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO DEPRECIATION EXPENSE.

A. As I noted earlier in my Direct Testimony, several adjustments to depreciation expense have been made in the cost of service studies presented in this rate case:

1) Adjust depreciation expenses related to the plant adjustments as previously discussed, e.g., AGIS (Attachments APF-1 and APF-2, Schedules 137);
2) Include the results of new common plant depreciation rates as proposed in 21AL-0317E; and
3) Annualize the year-end depreciation expense at the year-end June 2021 level in the 2021 HTY.

Q. PLEASE DISCUSS THE ADJUSTMENT FOR THE NEW DEPRECIATION RATES.

A. Company witnesses Mr. Watson and Ms. Wold sponsor the new depreciation study and associated depreciation rates, respectively. Consistent with her testimony, I have incorporated the annual impact of the changes in common plant depreciation rates to depreciation expense in the CTY and 2021 HTY presented in this rate case, shown on Attachments APF-1 and APF-2, Schedule 232. The Company will implement the change in Common General and Common Intangible depreciation rates with the effective date of rates from this rate case, to match when revenue begins to be collected for these expenses.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ANNUALIZE THE YEAR-END DEPRECIATION EXPENSE IN THE HTY COST OF SERVICE.

A. The Company has included an adjustment to the 2021 HTY to reflect the June 30, 2021 level of depreciation expense based on the June 2021 year-end plant balances. This adjustment is a known and measurable adjustment that will occur within one year of the test year and is consistent with prior Commission precedent. The adjustment is shown on Attachments APF-2, Schedule 226.

J. <u>Amortization Expense Adjustments</u>

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO AMORTIZATION EXPENSE.

A. Several adjustments to amortization expense have been made in the CTY and the 2021 HTY cost of service studies presented in this rate case. Adjustments were made to:

1) Eliminate the amortizations approved in the 2020 Gas Combined Rate Case and amortize any unamortized balances;

2) Eliminate any amounts that were deferred in the 2021 HTY above the expense baselines approved in the 2020 Gas Combined Rate Case;

3) Include amortizations of existing regulatory assets that have accrued since the 2020 Gas Combined Rate Case; and

4) Include new amortizations.

Q. DOES THE COMPANY PROPOSE ANY AMORTIZATION OF THE REGULATORY ASSETS APPROVED IN PRIOR PROCEEDINGS FOR PURPOSES OF THIS RATE CASE?

A. Yes. The Company is proposing to amortize regulatory assets approved in the 2020 Gas Combined Rate Case for deferred MGP expenses, property taxes, pension expenses, and Damage Prevention program expenses, as discussed in detail below. The amortization period for these deferred balances is specific to the test year that is approved. If the Commission approves the CTY, a 36-month period beginning with the effective date of rates from this proceeding is used. If, however, the Commission approves an HTY then the amortization period is 18 months.

Q. PLEASE EXPLAIN HOW YOU DETERMINED THE AMORTIZATION PERIODS.

A. Company witness Ms. McKoane provides the policy rationale for our approach to the amortization periods but generally speaking, the amortization periods were chosen to be representative of the expected time between rate cases. Rates based on the CTY will allow the Company to stay out of a rate case for a longer time whereas rates based on the HTY will require the Company to file another rate case much sooner due to the substantial amount of capital expected to be placed into service in the coming years.

Q. PLEASE DESCRIBE THE AMORTIZATION OF ENVIRONMENTAL INVESTIGATION, REMEDIATION, AND LITIGATION COSTS AT THE BOULDER SITE.

A. As discussed in more detail by Ms. McKoane in her Direct Testimony, in Decision No. R11-1311, mailed December 2, 2011, in Proceeding No. 11A-646G, the

Commission approved the Company's request to defer environmental investigation-, remediation-, and litigation-related costs associated with the MGP site located in Boulder. In Decision No. C13-0064 in Proceeding No. 12AL-1268G, the Commission authorized the Company to amortize the deferred balance as of December 31, 2012, for a total of $93,174 over an amortization period of two years, which expired August 9, 2015. The Company continued to defer subsequent costs along with any related credits from January 1, 2013, through December 31, 2014. By Decision No. C16-0123 in Proceeding No. 15AL-0135G, the Commission authorized the Company to amortize the deferred balance as of December 2014 of $419,802, over a 26-month period beginning November 1, 2015, and ending December 31, 2017. The Company continued to defer subsequent costs from January 1, 2015, through December 31, 2016. By Decision No. C18-1158 in the 2017 Gas Phase I, the Commission authorized the Company to amortize the deferred balance as of December 2016 of $50,838, over a 27-month period beginning January 1, 2018, and ending March 31, 2020. Finally in Decision No. R20-0673 in the 2020 Gas Combined Rate Case, the Commission authorized the Company to amortize the deferred balances of $3,007,040 as of September 30, 2019. The deferred balance as of October 31, 2022 is $1,002,347, as shown on Attachment APF-1, Schedule 123. The Company proposes to amortize the deferred balance over 36 months in the CTY and 18 months in the HTY, as previously discussed.

Q. WILL THE COMPANY CONTINUE THE DEFERRED ACCOUNTING AND AMORTIZATION TREATMENT APPROVED IN THE PAST FOR THE ENVIRONMENTAL CLEAN-UP COSTS AT THE BOULDER SITE?

A. No. Remediation at the Boulder site is complete so the Company is proposing to simply amortize the remaining unamortized balance as of the effective date of rates in this case.

Q. PLEASE DESCRIBE THE AMORTIZATION OF ENVIRONMENTAL INVESTIGATION AND REMEDIATION COSTS AT OR ORIGINATING FROM THE RICE YARDS SITE.

A. As discussed in more detail by Ms. McKoane in her Direct Testimony, in Decision No. R17-0705, mailed August 24, 2017, in Proceeding No. 17A-0435G, the Commission approved the Company's request to defer investigating, litigating, and remediating possible environmental contamination at or originating from the Rice Yards site and the Crown Tar Works site in Denver. The deferred balance related to the settlement of the City and County of Denver's claims at September 30, 2019, was $1,322,229. In Decision R20-0673 in the Company's 2020 Gas Combined Rate Case, the Commission authorized the amortization of this amount over 36 months. In this case, I have included a deferred balance of $7,525,503 as shown on Attachment APF-1, Schedule 123. This balance is made up of the remaining unamortized balance authorized in the 2020 Gas Combined Rate Case and additional remediation costs the Company is requesting for recovery as described by Ms. McKoane The Company proposes to amortize this deferred balance over 36 months in the CTY and 18 months in the HTY, as previously discussed.

Q. WILL THE COMPANY CONTINUE THE DEFERRED ACCOUNTING TREATMENT APPROVED IN THE PAST FOR THE ENVIRONMENTAL INVESTIGATION, REMEDIATION, AND LITIGATION COSTS RELATED TO THE RICE YARDS AND CROWN TAR WORK SITES?

A. Yes. Investigating, litigating, and remediating possible environmental contamination at the Rice Yards site and the Crown Tar Works site in Denver are not complete and therefore the Company will leave the regulatory asset on the books and continue deferral. Any additional deferred costs at the time of the next gas rate case will be brought forward to amortize at that time.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO ELIMINATE ANY AMOUNTS THAT WERE DEFERRED IN THE 2021 HTY ABOVE THE BASELINE LEVELS APPROVED IN THE 2020 GAS COMBINED RATE CASE.

A. In the 2020 Gas Combined Rate Case, the Commission approved a certain baseline level of costs in base rates associated with property tax expense, qualified and non-qualified pension expense, and damage prevention costs. The Company has been deferring costs above the baseline level since the effective date of rates from the 2020 Gas Combined Rate Case and is asking for recovery of these deferred balances in this case, as I discuss later in my Direct Testimony. However, to reset the level of these costs to actual amounts, and not the baseline levels from the 2020 Gas Combined Rate Case, the Company made adjustments in this case to eliminate any amounts that were deferred in the 2021 HTY above the baseline levels, as shown on Attachments APF-1 and APF-2, Schedule 279.

Q. PLEASE DISCUSS THE AMORTIZATIONS OF EXISTING REGULATORY ASSETS THAT HAVE BEEN DEFERRING COSTS ABOVE THE BASELINE LEVELS SINCE THE 2020 GAS COMBINED RATE CASE.

A. The Company has been deferring costs above the baseline levels since the effective date of rates in the 2020 Gas Combined Rate Case and will continue deferring until the effective date of rates in this case, expected November 1, 2022. The Company has included the actual deferred balances for those costs that have a tracker through June 30, 2021 and is proposing to amortize these balances in this case over 36 months in the CTY and 18 months in the HTY.

Q. PLEASE DISCUSS THE DEFERRED PROPERTY TAX AMORTIZATION.

A. As approved by the Commission in the 2020 Gas Combined Rate Case, the Company has deferred property taxes since the last rate case. The Company has recorded a regulatory asset for the difference in the retail property taxes included in base rates in the 2020 Gas Combined Rate Case and the actual incurred retail property taxes beginning with the effective date of rates, November 1, 2020. The deferral from the last rate case will continue until new rates are approved in this current case. The level of retail property taxes included in base rates in the 2020 Gas Combined Rate Case was $53,681,524. The Company is proposing to amortize the deferred retail property tax deferred balance through June 30, 2021 over 36 months in the CTY and 18 months in the HTY. The amortization of the property tax deferred balance through June 30, 2021 is shown on Attachments APF-1 and APF-2, Schedule 238.

Q. PLEASE DISCUSS THE QUALIFIED AND NON-QUALIFIED PENSION EXPENSE AMORTIZATION.

A. As approved by the Commission in the 2020 Gas Combined Rate Case, the Company has deferred pension expenses since the last rate case. The Company has recorded a regulatory liability account for the difference in retail pension expense included in base rates from the 2020 Gas Combined Rate Case and the actual pension expenses. The actual retail pension expenses have been lower than the amount in base rates, resulting in a regulatory liability. The deferral from the 2020 Gas Combined Rate Case will continue until new rates are approved in this current case. The level of retail pension expenses included in base rates in the 2020 Gas Combined Rate Case was as follows:

Non-Qualified Pension Expense	$157,857
Qualified Pension Expense	$8,230,556

The Company is proposing to amortize the actual deferred retail pension expense deferred balance through June 30, 2021 over 36 months in the CTY and 18 months in the HTY. The amortization of the pension expense deferred balance through June 30, 2021 is shown on Attachments APF-1 and APF-2, Schedule 238.

Q. PLEASE DISCUSS THE DAMAGE PREVENTION PROGRAM AMORTIZATION.

A. As discussed by Company witness Ms. Gilliland and noted above in my testimony, and as approved by the Commission in the 2020 Gas Combined Rate Case, the Company has deferred Damage Prevention expense since the last rate case. The Company has recorded a regulatory asset for the difference in the Damage Prevention expense included in base rates in the 2020 Gas Combined Rate Case and the actual incurred expenses beginning November 1, 2020. The deferral from the last rate case will continue until new rates are approved in this current case. The Company is proposing to amortize the actual Damage Prevention deferred balance of $8,434,345 through June 30, 2021. This balance is made up of the unamortized balance of the damage prevention amortization from the 2020 Gas Combined Rate Case and new deferred balances through June 30, 2021. The amortization of the Damage Prevention deferred balance is shown on Attachments APF-1 and APF-2, Schedule 123.

Q. PLEASE SUMMARIZE ANY NEW AMORTIZATIONS OF REGULATORY ASSETS OR LIABILITIES PROPOSED IN THIS CASE.

A. As discussed by Company witness Ms. Koch, the Colorado State Income Tax rate changed from 4.63 percent to 4.55 percent, effective January 1, 2020.[9] The Company is proposing in this case to return to customers the difference in Colorado State Income taxes from the amount included in current base rates from the 2020 Gas Combined Rate Case and a recalculated level of expense using the new Colorado State Income tax rate. This approach of returning to customers the impact of changes in tax rates is comparable to how the Company treated the change in the Federal Income Tax rate change several years ago (TCJA). The amount to be returned to customers was calculated from January 1, 2020 through the effective date of rates in this case, expected November 1, 2022, plus any excess deferred income taxes. This difference is a credit (reduction to the cost of

[9] Colorado Proposition 116.

service) and is being amortized over 36 months in the CTY and 18 months in the HTY, as shown on Attachments APF-1 and APF-2, Schedule 238.

Q. PLEASE SUMMARIZE ALL OF THE PROPOSED NON-PLANT AMORTIZATIONS INCLUDED IN THIS RATE CASE.

A. Please see Table APF-D-8 below, which shows the non-plant amortizations included in the CTY.

Table APF-D-8

		Amortization		
Description	**Deferred Balance**	**Time Period**	**Start Date**	**2022 CTY**
Boulder MGP	$1,002,347	36 Months	11/1/2022	$334,116
Damage Prevention	$8,434,345	36 Months	11/1/2022	$2,811,448
Property Tax	$13,196,319	36 Months	11/1/2022	$4,398,773
Rate Case Expenses	$2,823,469	36 Months	11/1/2022	$941,156
Qualified and Non-Qualified Pension Expense	$(616,759)	36 Months	11/1/2022	$(205,586)
Denver MGP	$7,525,503	36 Months	11/1/2022	$2,508,501
Colorado State Income Tax Rate Change	$(104,867)	36 Months	11/1/2022	$(34,956)
Total				**$10,753,452**

(1) Deferred Balances presented include unamortized balances from the 2020 Gas Combined Rate Case.

Q. PLEASE SUMMARIZE THE EXPENSE LEVELS INCLUDED IN THIS RATE CASE THAT WILL BE USED AS THE BASIS FOR DEFERRAL BEGINNING WITH THE EFFECTIVE DATE OF RATES FROM THIS RATE CASE.

A. Please see Table APF-D-9 below.

Table APF-D-9

Description	2022 CTY
Property Tax	$ 64,311,789
Non-Qualified Pension	$ 261,743
Qualified Pension	$ 4,966,723
Damage Prevention	$ 23,065,855
Gas CPUC Administration Fees	$ 3,913,433

The amounts presented in this table are the retail level of expenses in the CTY in this rate case.

K. Taxes Other Than Income Taxes Adjustments

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO PAYROLL TAX EXPENSE.

A. Adjustments were made to eliminate the payroll taxes associated with all the labor adjustments, as previously discussed. These adjustments are shown on the following schedules:

1) Employee wage increases and incentive compensation (Attachments APF-1 and APF-2, Schedules 247 and 248;
2) Discretionary Incentive Pay (Attachments APF-1 and APF-2, Schedule 278;
3) Long term incentive compensation (Attachments APF-1 and APF-2, Schedules 239, 240, and 241);
4) Aviation labor (Attachments APF-1 and APF-2, Schedule 224); and
5) Investor Relations labor (Attachments APF-1 and APF-2, Schedule 268).

Q. PLEASE DISCUSS THE PRESENTATION OF PROPERTY TAX EXPENSE IN THE CTY.

A. As discussed by Company witness Ms. Koch, the Company is requesting the estimated 2022 level of property tax expense in this case. Ms. Koch addresses the property taxes on a total Company basis. That information is then allocated to the electric, gas, thermal energy, and non-utility departments based on our gross plant balances. The gas property taxes are then allocated to the retail jurisdiction based on retail plant in service allocation factor. In addition, as discussed by Company witness Ms. McKoane, the Company is proposing to continue the property tax expense tracker. If property tax expenses incurred after the effective date of rates in this case, expected November 1, 2022, are greater or less than the level included in this rate case, the difference will be deferred in a regulatory asset/liability account, and the regulatory asset/liability would be brought forward for recovery in a future rate case.

Q. PLEASE DISCUSS THE ADJUSTMENT TO PROPERTY TAX EXPENSE PRESENTED IN THE 2021 HTY.

A. The Company started with the actual property tax expense for the 12 months ended June 30, 2021, and then made one adjustment for the property tax expenses included in the 2021 HTY. An adjustment was made to eliminate the property taxes associated with the Front Range pipeline.

L. <u>Income Tax Expense Adjustments</u>

Q. HOW IS THE INCOME TAX EXPENSE CALCULATED FOR THE COST OF SERVICE STUDY PRESENTED IN THIS RATE CASE?

A. Taxable income is determined by calculating taxable income, after which synchronized interest expense is deducted, taxable temporary additions/deductions (these are also known as “Schedule M items”) were added, and permanent tax differences are added, to arrive at taxable income. In the cost of service study presented in this rate case, the Schedule M items, permanent tax differences, and deferred income tax expense related to plant are detailed on Attachments APF-1 and APF-2, Schedule 200. The Schedule M items, permanent tax differences, and deferred income tax expense related to non-plant are detailed on Attachments APF-1 and APF-2, Schedule 115. The state and federal income tax rates are then applied to taxable income to arrive at current income tax expense. The federal income tax rate reflects the 21 percent rate effective January 1, 2018 with the enactment of the TCJA. The state income tax rate reflects the 4.55 percent rate effective January 1, 2020. Deferred income tax expense, the amortization of investment tax credits, and tax credits are added to arrive at total tax expense. The taxable additions/deductions and the deferred income taxes are being presented in this rate case at the same level of detail, in order to properly allocate to the retail jurisdiction. In the cost of service study, the deferred income taxes and tax credits related to non-plant are detailed on Attachments APF-1 and APF- 2, Schedule 115.

Q. IS THE COMPANY'S APPROACH TO CALCULATING INCOME TAXES THE SAME AS IN PRIOR RATE CASES?

A. Yes.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO INCOME TAX EXPENSE.

A. The adjustments to current federal and state income tax expense and deferred income tax expense include:

1) The plant adjustments as previously discussed, e.g AGIS. (Attachment APF-1, Schedules 137);
2) The elimination of accounts that are not included in the cost of service study (Attachments APF-1 and APF-2, Schedule 115); and,
3) Deferred tax expense includes an annual amount of amortization of the excess ADIT as a result of implementing the TCJA (Attachments APF-1 and APF-2, Schedule 115).

Q. IS THE COMPANY IN A NET OPERATING LOSS TAX POSITION IN THE 2020 HTY?

A. No. As previously discussed, the Company is not in a NOL tax position in the CTY or the 2021 HTY. The Company has enough taxable income in 2022 and 2021 to use all of the income tax addition/deductions. Furthermore, the Company is also able to utilize all of the NOL Carryforward from prior years in the HTY. As a result, there is not an NOL carryforward in the CTY. However, with any changes in the final Commission-ordered revenue deficiency from the filed revenue deficiency, the NOL calculation will need to be recalculated. If there is a NOL, an adjustment will have to be made to include a Schedule M adjustment in the current income tax calculation to offset the negative taxable income. This Schedule M will then be multiplied by the composite tax rate, and an adjustment will be made to deferred income tax expense and ADIT. The NOL calculation is presented on Attachments APF-1 and APF-2, Schedule 104.

VIII. <u>AFUDC OFFSET TO EARNINGS</u>

Q. IS THE COMPANY INCLUDING AN ADJUSTMENT TO INCLUDE AFUDC AS AN OFFSET TO EARNINGS IN THIS RATE CASE?

A. Yes. The Commission has a long-standing ratemaking policy that if CWIP is included in rate base, then an AFUDC offset to earnings is required. When year-end rate base is used, as in the HTY, AFUDC is annualized at the year-end level, as of June 30, 2021, to match the year-end CWIP balance. The adjustment to annualize AFUDC is shown on Attachment DAB-1, Schedules 225 and 236. An AFUDC offset is also included in the CTY but there is no annualization adjustment since CWIP is included in rate base at a 13 month average level.

IX. JURISDICTIONAL ALLOCATION

Q. PLEASE DESCRIBE THE BASIS OF THE RETAIL JURISDICTIONAL ALLOCATORS USED IN THIS RATE CASE.

A. The retail jurisdictional allocations used in this rate case are either a “fundamental” allocator or a “derived” allocator. Fundamental allocators include the system production demand, system transmission demand, system distribution demand, and annual energy that are determined from test year loads and sales. Derived allocators are determined within the cost of service study, as the resulting percentage of the total of other allocated cost items. For example, the total plant allocator would be the percentage of the total plant assigned to each jurisdiction, where each of the various components of plant would have been allocated using a different fundamental allocator.

Q. WHAT RETAIL JURISDICTIONAL ALLOCATION FACTORS DID YOU USE IN THE COST OF SERVICE STUDY PRESENTED IN THIS RATE CASE?

A. The jurisdictional allocation factors are presented on Attachments APF-1 and APF-2, Schedule 300. The derivation of the labor allocation factors is presented on Attachments APF-1 and APF-2, Schedule 300. The jurisdictional allocation factors for the HTY and CTY were developed using the Dth throughput and peak day loads for both the retail and wholesale customers .

Q. IS THE COMPANY PROPOSING TO CHANGE THE ALLOCATION OF COSTS TO THE RETAIL JURISDICTION IN THIS RATE CASE?

A. No.

X. CAPITAL STRUCTURE

Q. WHAT IS THE BASIS FOR THE CAPITAL STRUCTURE USED IN THE CTY?

A. The long-term debt, short-term debt, and equity balances included in the CTY capital structure are based on the 13-month average December 31, 2022 balances. The capital structure is shown on Attachment APF-1, Schedule 002, as sponsored by Company witness Mr. Paul A. Johnson.

Q. WHAT IS THE BASIS FOR THE CAPITAL STRUCTURE USED FOR THE 2021 HTY?

A. The long-term debt, short-term debt and equity balances included in the 2020 HTY capital structure are based on the 13-month average June 30, 2021 balances. The capital structure is shown on Attachment APF-2, Schedule 002, as sponsored by Company witness Mr. Johnson.

Q. DID THE COMPANY MAKE ANY ADJUSTMENTS TO THE CAPITAL STRUCTURES PRESENTED IN THIS RATE CASE?

A. Yes. These adjustments to the balances are reflected in Attachments APF-1 and APF-2, Schedule 002.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO COMMON EQUITY.

A. Adjustments to common equity were made to eliminate the effect of subsidiaries, net non-utility plant, other investments, other funds, and other comprehensive income. These adjustments are consistent with those approved by the Commission in previous Company rate cases.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO DEBT.

A. Adjustments to debt were made to eliminate the effect of subsidiaries, specifically, eliminating any notes receivable from subsidiaries or notes payable to subsidiaries. Company witness Mr. Johnson discusses the calculation of long-term debt and short-term debt in his Direct Testimony.

Q. HOW WAS THE COST OF DEBT CALCULATED IN THIS RATE CASE?

A. As discussed by Mr. Johnson, the Company calculated the cost of long-term debt based on a yield-to-maturity calculation where interest costs plus all related issuance costs are divided by the 13-month average principal amount of the bonds. The cost of short-term debt is calculated using debt costs, including interest on commercial paper and credit facility fees, divided by the 13-month average amount of the short-term debt outstanding.

XI. REVENUE REQUIREMENT AND REVENUE DEFICIENCY

Q. WHAT IS THE OVERALL RETAIL REVENUE REQUIREMENT FOR THE CTY?

A. The overall retail revenue requirement for the CTY is $825,150,684.

Q. WHAT IS THE REVENUE DEFICIENCY INDICATED BY THE CTY COST OF SERVICE STUDY?

A. The revenue deficiency is calculated by comparing the overall retail revenue requirements to the present base revenues. The resulting CTY revenue deficiency is $214,637,700, as shown on Attachment APF-1, Schedule 001.

Q. WHAT IS THE OVERALL REVENUE REQUIREMENT AND DEFICIENCY INDICATED FOR THE 2021 HTY COST OF SERVICE?

A. The overall retail revenue requirement for the informational 2021 HTY is $791,965,811 and the revenue deficiency is $173,444,456, as shown on Attachment APF-2, Schedule 001.

Q. DOES THIS CONCLUDE YOU DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Arthur P. Freitas

I graduated from Marquette University with a Bachelor's degree in Business Administration in 1994. I worked for Boston Gas Company from 1998 through 2000 as a rate analyst. In 2000, I began working for a consulting group, La Capra Associates. While at La Capra Associates, I gained a broad range of experience and expertise that encompassed utility functions from system planning through retail ratemaking. I performed analyses on a range of topics that included retail cost allocation and rate design, electricity market design and analysis, power market forecasting, and integrated resource planning. I have significant experience involving the regulatory process. I have participated in the regulatory process on behalf of both regulated utilities and other interested stakeholders in multiple states. The issues explored include cost allocation and retail rate design, integrated resource planning, resource acquisition, transmission system expansion, and renewable energy policy. During the course of my involvement in numerous regulatory proceedings, I have drafted and reviewed pre-filed testimony, developed and responded to discovery, and conducted analyses on issues relevant to the proceeding to support the testimony of expert witnesses. In 2011, I joined XES as Principal Rate Analyst and was promoted to Manager of Revenue Analysis for Public Service's affiliate Company Southwestern Public Service Company ("SPS"). I assumed my current role as Manager of Revenue Analysis for Public Service in April 2020.

I submitted pre-filed testimony before the Colorado Public Utilities Commission on the revenue requirement calculation in Proceeding Nos. 20A-0204E and 20A-0300E. I have also testified before the New Mexico Public Regulation Commission in Case No. 17-

00255-UT on SPS's cost of service and on transmission costs. I also submitted pre-filed testimony on those same issues in Case Nos. 19-00170-UT, 15-00139-UT, and 15-00296-UT. In Case No. 17-00044-UT I submitted testimony on the revenue requirement calculations in an application for a Certificate of Convenience and Necessity to construct two wind projects. I testified before the Public Utility Commission of Texas ("PUCT") in Docket No. 43695, a rate case filed in 2014, regarding expenses incurred and revenues received from the Southwest Power Pool and other utilities under the applicable Open Access Transmission Tariff. In addition, I submitted pre-filed testimony in PUCT Docket Nos. 49831, 47527 and 45524, both of which were base rate cases. I also submitted pre-filed testimony to the PUCT in Docket Nos. 42042 and 42004 regarding transmission-related costs incurred under tariffs approved by the Federal Energy Regulatory Commission. In Docket No. 46936, I submitted testimony on the revenue requirement calculations in the companion application in Texas for a Certificate of Convenience and Necessity to construct two wind projects. I have also submitted pre-filed testimony on cost of service and formula rate mechanisms before the FERC in Docket Nos. ER19-404, ER19-675, and ER20-277. Finally, I have testified before the Massachusetts Department of Public Utilities on behalf of Blackstone Gas Company, and I have submitted pre-filed testimony to the New Hampshire Public Utilities Commission on behalf of the Office of Consumer Advocate.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * *

IN THE MATTER OF ADVICE NO. 993-GAS OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 6-GAS TARIFF TO INCREASE JURISDICTIONAL BASE RATE REVENUES, IMPLEMENT NEW BASE RATES FOR ALL GAS RATE SCHEDULES, AND MAKE OTHER PROPOSED TARIFF CHANGES EFFECTIVE FEBRUARY 24, 2022	) **PROCEEDING NO. 22AL-______G**

AFFIDAVIT OF ARTHUR P. FREITAS
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Arthur P. Freitas, 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 21st day of January, 2022.

Arthur P. Freitas
Manager, Revenue Analysis

Subscribed and sworn to before me this 21st day of January, 2022.

MARY K PARKER
NOTARY PUBLIC - STATE OF COLORADO
NOTARY ID 20214033166
MY COMMISSION EXPIRES AUG 19, 2025

Mary K Parker
Notary Public

My Commission expires 8-19-2025