BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE NO. 1797-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8-ELECTRIC TARIFF TO IMPLEMENT RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**) PROCEEDING NO. 19AL-______E**

DIRECT TESTIMONY AND ATTACHMENTS OF DEBORAH A. BLAIR

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

May 20, 2019

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

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
2002 Rate Case	Proceeding No. 02S-315EG
2014 Rate Case	Proceeding No. 14AL-0660E
2016 Depreciation Case	Proceeding No. 16A-0231E
AGIS CPCN Projects	Proceeding No. 16A-0588E
ADIT	Accumulated Deferred Income Tax
AFUDC	Allowance for Funds Used During Construction
AGIS	Advanced Grid Intelligence and Security
AIP	Annual Incentive Pay
AMI	Advanced Metering Infrastructure
A&G	Administrative and general
CACJA	Clean Air-Clean Jobs Act
Commission	Colorado Public Utilities Commission
CPCN	Certificate of Public Certification and Necessity
CRS	Customer Resource System
CWIP	Construction Work in Progress
Depreciation Case	Proceeding No. 16A-0231E
DSM	Demand-Side Management
DSMCA	Demand-Side Management Cost Adjustment
ECA	Electric Commodity Adjustment
EOC	Energy Outreach Colorado
EZITC	Enterprise Zone Investment Tax Credits

Acronym/Defined Term	Meaning
FAN	Field Area Network
FIN 48	Financial Interpretation 48, “Accounting for Uncertainty in Income Taxes”
FERC	Federal Energy Regulatory Commission
GRSA	General Rate Schedule Adjustment
HTY	Historical Test Year
ICT	Innovative Clean Technology
ISOC	Interruptible Service Option Credit
ITC	Investment Tax Credits
IVVO	Integrated Volt-Var Optimization
I&S	Investigation and suspension
JDA	Joint Dispatch Agreement
MPB	Mountain Pine Beetle
NCEC	New Century Energy Communications, Inc.
NOL	Net Operating Loss
OATT	Open Access Transmission Tariff
OCC	Office of Consumer Counsel
OCI	Other comprehensive income
O&M	Operations and Maintenance
PCCA	Purchased Capacity Cost Adjustment
PHFU	Plant Held for Future Use
PPS	Probability Proportional to Size
PTC	Production Tax Credits
PTP	Point-to-Point

Acronym/Defined Term	**Meaning**
Public Service or the Company	Public Service Company of Colorado
RESA	Renewable Energy Standard Adjustment
RIS	Rate Information System
RDA	Revenue Decoupling Adjustment
RD-TDR	Residential demand – time differentiated rate
RE-TOU	Residential time of use
ROE	Return on Equity
RORB	Return on Rate Base
Schedule M items	Taxable addition/deductions
SCR	Selective Catalytic Reduction
TCA	Transmission Cost Adjustment
TCJA	Tax and Jobs Act 2017
WACC	Weighted average cost of capital
Xcel Energy	Xcel Energy Inc.
XES or Services Company	Xcel Energy Services Inc.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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RE: IN THE MATTER OF ADVICE NO.	**)**
1797-ELECTRIC OF PUBLIC SERVICE	**)**
COMPANY OF COLORADO TO REVISE	**)**
ITS COLORADO P.U.C. NO. 8-	**) PROCEEDING NO. 19AL-______E**
ELECTRIC TARIFF TO IMPLEMENT	**)**
RATE CHANGES EFFECTIVE ON	**)**
THIRTY-DAYS' NOTICE.	**)**

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

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Deborah A. Blair. My business address is 1800 Larimer Street, Denver, Colorado 80202.

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

A. I am employed by Xcel Energy Services Inc. ("XES") as Director, 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 Director, Revenue Analysis, I am responsible for determining the overall revenue levels required by Public Service and Southwestern Public Service Company, another Xcel Energy regulated utility subsidiary. 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 testimony is to present the Electric Department's revenue requirement study, also known as the cost of service study, which supports the required increase in base rate revenues the Company is requesting in this rate review. As discussed by Company witness Ms. Brooke A. Trammell, the Company is proposing to utilize a Historical Test Year ("HTY") in this rate review, with pro forma adjustments for known and measurable changes in 2019 and a request to include in rate base certain capital additions expected to close to plant in-service by December 31, 2019 (referred to as the requested "capital reach"). The HTY cost of service is the 12 months ended December 31, 2018. The overall retail revenue requirement for 2018 is $1,951,002,985. I also explain the rationale for, and effect of, many of the adjustments included in the cost of service study. The Company is proposing General Rate Schedule Adjustments ("GRSA") that will be implemented at the conclusion of this case.

Additionally, I present the amount of transmission costs included in the 2018 HTY that will be used to set the base amount used to calculate the Transmission Cost Adjustment ("TCA"), the revenue requirement associated with the Clean Air-Clean Jobs Act ("CACJA") Rider that will be included in base rates, and the revenue requirement associated with the Rush Creek Wind Project that will be included in base rates. Finally, I present the costs and revenues associated with the Joint Dispatch Agreement ("JDA").

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

A. Yes, I am sponsoring Attachments No. DAB-1 through DAB-13, which were prepared by me or under my direct supervision. The attachments are as follows:

- Attachment DAB-1 - Revenue Requirement Study for Public Service Company's Electric Department Based on the 2018 Test Year;
- Attachment DAB-2 – Functional Cost of Service for the 2018 Test Year;
- Attachment DAB-3 - Comparison of 2018 HTY versus the cost of service supporting the Company's current base rates approved in Proceeding No. 14AL-0660E;
- Attachment DAB-4 - 2018 detail of Per Book Operations and Maintenance expenses split by Service Company and native Public Service expenses;
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- Attachment DAB-7 - Lead-lag Study Summary that supports the Cash Working Capital Factors Used in the Cost of Service Study;
- Attachment DAB-8 - Detailed Lead-Lag Study Support, including CD-ROM of Revenue Lag detail;
- Attachment DAB-9 - Labor Productivity Study;
- Attachment DAB-10 - CD-ROM - Copies of Recoverable Advertisements for 12 Months Ended December 31, 2018;
- Attachment DAB-11 – Clean Air-Clean Jobs Act Costs in Base Rates;
- Attachment DAB-12 – Rush Creek Costs in Base Rates; and
- Attachment DAB-13 – Transmission Cost Adjustment Costs in Base Rates.

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

A. I recommend the Commission approve the retail electric revenue requirement for the 2018 HTY of $1,951,002,985, and the resulting GRSA factors. I recommend the Commission approve the TCA and AGIS level of costs in base rates, as well as the inclusion of CACJA Rider and Rush Creek Wind Project revenue requirements in base rates. Finally, I recommend the Commission approve the net JDA revenues.

II. TEST YEAR REVENUE DEFICIENCY

Q. PLEASE SUMMARIZE THE RESULTS OF THE REVENUE REQUIREMENT STUDY FOR THE 2018 HTY.

A. The 2018 HTY revenue requirement study shows total revenue requirement, excluding electric energy and electric purchased capacity costs collected in the Electric Commodity Adjustment ("ECA") and the Purchased Capacity Cost Adjustment ("PCCA"), and costs collected through the Demand-Side Management Cost Adjustment ("DSMCA"), of $1,951,002,985. This is based on the proposed return on equity ("ROE") of 10.35 percent, as recommended by Company witness Ms. Ann E. Bulkley, a long-term cost of debt of 4.18 percent and a capital structure of 56.46 percent equity and 43.54 percent debt, as recommended by Company witness Ms. Sara W. Soong, which results in an overall return on rate base of 7.66 percent (i.e., the Company's Weighted Average Cost of Capital ("WACC")). When compared to our present revenue (including the current negative General Rate Schedule Adjustment ("GRSA") of 4.19 percent) of $1,543,265,209, this revenue requirement results in a base rate revenue increase of $407,737,776. This base rate revenue increase includes rolling in the costs that are currently recovered in several cost recovery mechanisms that are revenue neutral in total to the Company's electric customers.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO ROLL-IN COSTS CURRENTLY RECOVERED IN SEVERAL RECOVERY MECHANISMS THAT ARE REVENUE NEUTRAL IN TOTAL TO THE COMPANY'S ELECTRIC CUSTOMERS.

A. As previously mentioned, the Company is proposing to roll-in costs that are currently recovered in several recovery mechanisms that are revenue neutral to Public Service's retail electric jurisdiction. First, as discussed by Company witness Ms. Trammell, the Company is proposing to recover the costs that are currently recovered in the CACJA Rider approved by the Commission in the Company's last electric Phase I rate case, Proceeding No. 14AL-0660E ("2014 Electric Rate Case"), in base rates and eliminate the CACJA Rider. Therefore, costs that would have historically been recovered through this mechanism are included in the revenue requirement in this rate review. Including the CACJA costs in base rates has the effect of increasing the base rate revenue deficiency by an estimated $78.7 million.

Second, the base rate increase also includes the shift of $40 million of transmission costs that would otherwise be recovered through the TCA effective with rates from this rate review, based on the 2018 HTY level of these costs. The Company is proposing to roll-in costs associated with the TCA into base rates in this rate review, but, as with the CACJA costs, this is revenue neutral and does not reflect an overall increase in rates to our customers. This revenue neutral change is the result of shifting the recovery of certain costs from a rate rider to recovery through base rates.

Third, similar to the CACJA Rider and the TCA, the Company is proposing to roll-into base rates the recovery of costs that are currently recovered through the ECA associated with Rush Creek Wind Project, as approved by the Commission in Proceeding No. 16A-0117E. I would note the Federal Production Tax Credits ("PTCs") and Capital Cost Sharing associated with the Rush Creek Wind Project will continue to flow through to customers through the ECA. Including the Rush Creek Wind Project revenue requirements currently recovered through the ECA in base rates has the effect of increasing the base rate revenue deficiency by an estimated $130.7 million.

Finally, the base rate increase includes the impacts of the Tax Cuts and Jobs Act of 2017 ("TCJA") that were implemented January 1, 2018, which is a reduction to the Company's costs. Currently, customers' rates have been reduced to reflect the impact of the TCJA from January 1, 2018 through December 31, 2019, as approved by the Commission in Proceeding No. 18M-0074EG.[1] I present a more detailed discussion of the TCJA impacts later in my Direct Testimony.

The roll-in of the CACJA Rider, TCA, and Rush Creek Wind Project, net of the impacts of the TCJA into base rates is revenue neutral and does not reflect an

[1] The total impact of the TCJA in current base rates from the 2014 Electric Rate Case was $101.2 million. In the TCJA Revised Settlement approved by the Commission in Proceeding 18M-0074EG, customers rates were reduced by $42.4 million in 2018 and $67.5 million in 2019, with the remaining TCJA savings being applied to the Legacy Pre-Paid Pension Asset.

increase in rates to our customers. I present the impact of the roll-in of the CACJA Rider, TCA and Rush Creek Wind Project later in my Direct Testimony. Excluding the effects of the inclusion of the CACJA Rider, TCA, and Rush Creek Wind Project costs, net of the TCJA impacts, the Company is seeking a net increase in revenues of $158,314,011.

Q. PLEASE DESCRIBE HOW THE COST RECOVERY MECHANISMS WILL BE REVENUE NEUTRAL TO CUSTOMERS EFFECTIVE WITH BASE RATES FROM THIS RATE REVIEW.

A. On November 1, 2019, the Company will file to implement its annual TCA rider to recover the incremental costs in plant in-service and Construction Work In Progress ("CWIP") balances since the last rate case, effective January 1, 2020. The plant in-service balances included in the annual TCA rider are included in the rate base balances in the 2018 HTY. Therefore, effective with the base rates from this rate review, the Company will reduce the TCA rider to remove these costs that are included in base rates from this rate review. Going forward, the TCA rider will continue to recover the incremental costs in plant in-service and CWIP balances measured from the balances included in the 2018 Test Year, plus any prior period true-ups. I provide the level of costs that the TCA rider will be measured from later in my testimony.

Also, in November 2019, the Company will file the CACJA Rider for rates effective January 1, 2020 ("2020 CACJA Rider"). The plant in-service balances, plant-related costs, and variable non-fuel operating and maintenance expenses included in the 2020 CACJA Rider are included in the 2018 HTY. Therefore, effective with the base rates from this rate review, the Company will reduce the CACJA Rider to remove these costs that are included in base rates from this rate review. Going forward, the CACJA will be zeroed out except for any prior period true-ups. I provide the level of costs in the 2018 HTY associated with CACJA Rider later in my testimony.

Finally, in December 2019, the Company will file the ECA for rates effective January 1, 2020 ("2020 ECA"). The portion of the 2020 ECA that is recovering the Rush Creek Wind Project revenue requirement is included in the 2018 HTY. The Federal Production Tax Credits and the Capital Cost Sharing will continue to be recovered through the ECA. Therefore, effective with base rates from this rate review, the Company will reduce the ECA to remove the costs that are included in base rates in this rate review. Going forward, the portion of the ECA related to the recovery of the Rush Creek Wind Project will be zeroed out, except for any prior period true-ups. I provide the level of costs in the 2018 HTY associated with the Rush Creek Wind Project later in my testimony.

Q. AFTER TAKING INTO CONSIDERATION THE SHIFT OF CACJA, TCA, AND RUSH CREEK COSTS, NET OF THE IMPACT OF TCJA INTO BASE RATES, WHAT IS THE RESULTING NET INCREASE IN BASE REVENUES THE COMPANY IS REQUESTING IN THIS RATE REVIEW?

A. The Company is requesting a net $158.3 million base rate increase in this rate review from the level of base rate revenues approved in the 2014 Rate Case, as shown in Table DAB-D-1 below:

Table DAB-D-1

Revenue Requirements per 2018 Test Year Cost of Service	$ 1,951,002,985
Less: Revenues Under Present Base Rates	$ 1,610,815,905
Less: Present GRSA Revenue (-4.19%)	$ (67,550,696)
Total Base Rate Increase Requested	$ 407,737,776
Less: Shift in Costs from CACJA to Base Rates	$ 78,719,151
Less: Shift in Transmission Costs from TCA to Base Rates	$ 40,027,376
Less: Shift in Costs from ECA for Rush Creek to Base Rates	$ 130,677,238
Net Increase	$ 158,314,011

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

A. As discussed by Ms. Trammell, the Company has included the costs of the Advanced Grid Intelligence and Security ("AGIS") projects in this rate review, including those specific projects approved by the Colorado Public Utilities Commission ("Commission") in Proceeding No. 16A-0588E ("AGIS CPCN"). In addition, the Company is requesting to include Wildfire Mitigation costs and certain capital additions that are expected to be in-service before December 31, 2019. The other drivers of the net increase in base rates the Company is requesting in this rate review are an increase in depreciation rates as approved in the 2016 Depreciation Case and the elimination of the amortizations of deferrals from prior rate cases.

In this case, the Company is eliminating the amortization expense associated with deferrals from the 2014 Electric Rate Case. Specifically, the amortizations of deferrals from the 2014 Electric Rate Case are related to property taxes deferred during 2012 through 2014, and the Legacy Prepaid Pension Asset.[2] The property tax regulatory asset balance was completely amortized at the end of December 31, 2017. However, in compliance with the 2014 Electric Rate Case Settlement, the Company has continued to record amortization expense and credit the property tax tracker regulatory asset balance until base rates are implemented in the next rate review. The Legacy Prepaid Pension Asset amortization is ending in July 2019 with the regulatory asset fully amortized. The Company will continue to record amortization expense and credit the Prepaid Pension Asset until the effective date of rates from this rate review, requested January 1, 2020. Both of these amortizations are being recovered in current base rate revenue, and once final rates are approved in this case, the amortization expense and reductions

[2] The 2014 Electric Rate Case Settlement defines Public Service's contributions to its pension plans recorded as a regulatory asset through December 31, 2014, as a "Legacy Pre-Paid Pension Asset."

(credits) to the regulatory assets will end. The revenue deficiency presented in this case is lower than it would have been absent removing these amortizations.

The remaining net increase in base rates is due to an increase in rate base driven by increases in net plant, increases in depreciation expense and property tax, offset by an increase in base revenue driven by increased sales. Operations and Maintenance ("O&M") expenses, exclusive of AGIS, Wildfire Mitigation, CACJA Rider and the Rush Creek Wind Project are slightly decreasing. The plant additions, net of retirements since the 2014 Electric Rate Case through 2018 are provided in Table DAB-D-2 below:

Table DAB-D-2

Net Plant Additions by Function					
	2014	**2015**	**2016**	**2017**	**2018**
Hydro Production	$ 6,357,917	$ 1,291,378	$ 19,735,480	$ 1,199,239	$ 2,631,351
Other Production	$ 11,336,487	$ 569,459,393	$ 11,272,093	$ 15,509,096	$ 944,558,961
Steam Production	$ 349,865,628	$ (54,601,743)	$ 73,175,282	$ (192,254,019)	$ 12,924,798
Total Production	$ 367,560,032	$ 516,149,029	$ 104,182,855	$ (175,545,684)	$ 960,115,109
Transmission	$ 113,963,090	$ 81,567,632	$ 106,984,030	$ 77,319,580	$ 296,210,437
Distribution	$ 249,009,601	$ 200,298,866	$ 217,271,068	$ 208,242,227	$ 237,457,739
Electric General & Intangible	$ 166,747,219	$ 49,554,821	$ 59,310,095	$ (2,312,038)	$ 41,573,830
Common General & Intangible[3]	$ 73,214,215	$ 28,975,540	$ 51,518,552	$ 88,711,040	$ (8,445,944)
Total	$ 970,494,157	$ 876,545,887	$ 539,266,601	$ 196,415,124	$ 1,526,911,171

These plant additions and changes in O&M are described in more detail by the Company's Business Area witnesses: Mr. Kyle I. Williams, Ms. Connie L. Paoletti,

[3] The Common General and Common Intangible 2014 through 2018 Plant Additions are total Company numbers. The electric portion is approximately 71 percent.

Mr. Chad S. Nickell, Mr. David C. Harkness, Mr. Adam R. Dietenberger, Mr. Daniel C. Brown, and Mr. Richard R. Schrubbe. The increases in sales are discussed by Company witness Ms. Jannell E. Marks. I have prepared a comparison of the 2018 HTY cost of service as compared to the 2013 HTY as approved in the 2014 Electric Rate Case, in Attachment DAB-3.

III. COST OF SERVICE STUDY

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

A. As I previously stated, Public Service is filing a calendar 2018 Historical Test Year for the cost of service presented in this rate review.

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 12-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. A number of rate case principles established in previous cases are used to calculate the cost of service study. To the extent that the cost of service study presented in this rate review departs from principles applied in previous cases, I discuss the changes below or such proposed changes are addressed by Company witnesses Ms. Trammell. The revenue requirement 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 RATE REVIEW?

A. The starting point in developing the 2018 HTY cost of service is the Company's books and records. The Company uses the FERC System of Accounts[4] as the basis for the book numbers in the cost of service. The per book plant balances presented in the 2018 HTY are in the roll forward schedules supported by Company witness Ms. Laurie J. Wold. The 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 presented in this rate review:

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 present base revenues, based on current rates applied to actual test period 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.

[4] 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.

The cost of service study presented in this rate review for calendar year 2018 is shown on Attachment DAB-1. For ease of reference, I have included an Index of Schedules at the beginning of this Attachment. The Schedules generally follow this order:

- Schedule 1 – Revenue Requirement
- Schedule 2 – General Rate Schedule Adjustment
- Schedule 3 – Capital Structure
- Schedules 100 through 199 – Rate Base and Support for Rate Base Adjustments
- Schedules 200 through 299 – Income Statement and Support for Income Statement Attachments
- Schedules 300 through 399 – Jurisdictional and Functional Allocation Factors

Q. HAS THERE BEEN ANY CHANGE IN THE COST OF SERVICE MODEL USED BY THE COMPANY IN THIS RATE REVIEW FROM PRIOR ELECTRIC CASES?

A. Yes. The Company converted its cost of service model from an Excel® spreadsheet model to a new software system, the Rate Information System ("RIS"), a system developed by Utilities International. The revenue requirement formula has not changed. The Company is providing an executable model in Excel® format, exported from RIS, that performs the revenue requirement calculations, plus the supporting schedules. I would note the RIS model was used for the cost of service presented in the Company's recently completed gas rate case, Proceeding No. 17AL-0363G and the recently filed Steam rate case, Proceeding No. 19AL 0063ST.

Q. IS THERE ANY ADDITIONAL INFORMATION YOU ARE PRESENTING IN THIS RATE REVIEW TO SUPPORT THE PER BOOK DATA PRESENTED IN ATTACHMENT DAB-1?

A. Yes. I am providing additional supporting information in this rate review for the O&M expenses split by Service Company and native Public Service expenses, shown in Attachment DAB-4. I am also providing in Attachment DAB-5, an Excel® spreadsheet (provided as a CD-ROM) that includes the detailed 2018 actual O&M data used as inputs to the HTY. The data presented in Attachment DAB-5, 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 2018 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, fuel and purchased power costs collected through the ECA and PCCA 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 for out-of-period amounts that are recorded in the HTY that are applicable to prior period are eliminated, or if amounts are applicable to the HTY that were recorded after the HTY, would be 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. 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 REVIEW?

A. I have incorporated the following adjustments and regulatory principles, as previously established by the Commission in previous rate cases, into 2018 HTY revenue requirements study presented in Attachment DAB-1.

<u>Rate Base</u>

- Rate Base is calculated using a year-end balance methodology except for Cash Working Capital, and other non-plant rate base items;
- The inventory balances for the coal, oil and natural gas used to generate the electricity we deliver to our customers are calculated using the average of the 12 monthly average balances during the test year;
- 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 ADIT balances are calculated using the year-end balances and 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 year-end balances to match the method of measuring rate base;

- Pre-Funded Allowance for Funds Used During Construction ("Pre-Funded AFUDC") associated with the Comanche project that was included in rate base in prior rate cases earning a current return is included in rate base;
- Pre-Funded AFUDC associated with the transmission assets recovered through the TCA and earning a current return is included in rate base;
- Excess AFUDC associated with the CACJA projects, resulting in the difference between the FERC AFUDC rate and the Company's Return on Rate Base ("RORB"), is included as an increase to rate base;
- Intangible Plant in Service is functionalized;
- Common plant is allocated to the electric 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 AFUDC addition to earnings based on the year-end balance. The Company annualized the AFUDC addition to earnings;
- An adjustment is made to eliminate contractor retentions from CWIP;
- ADIT and Deferred Income Tax expense are adjusted for the interest on CWIP;
- An adjustment is made to eliminate from plant in-service 50 percent of the investment in specific distribution substations serving Holy Cross Rural Electric Association;
- An adjustment is made to eliminate from plant in-service the amount of cost associated with the Pawnee turbine blade project that exceeded the Commission-ordered expenditure cap;
- An adjustment is made to eliminate from plant in-service the amount of costs associated with the Ponnequin wind project, as this asset is recovered through the RESA;
- Capital lease assets are not included in rate base;

- The acquisition premium associated with the acquisition of the Calpine assets, is recorded in the following FERC Accounts are included in rate base: Account 114 – Acquisition Adjustment, Account 115 – Accumulated Amortization of Acquisition Adjustment, and Account 407-Amortization of Acquisition Adjustment;

- Plant Held for Future Use ("PHFU") is included in rate base;

- Southeast Water Rights are eliminated from future use plant, and an adjustment to miscellaneous service revenue for the debt recovery of the asset is included;

- Regulatory assets associated with the early retirements and cost of removal of the Arapahoe Units 1 through 4, Cameo Units 1 and 2, Cherokee Units 1 through 4, Valmont Unit 5, Zuni Units 1 and 2, Craig Unit 1 and Comanche Units 1 and 2 are included in rate base (note that the early retirements of Arapahoe, Cameo and Zuni were first addressed in the 2009 Rate Case (Proceeding No. 09AL-299E), the early retirements of Cherokee and Valmont were approved in the proceeding to implement the Clean Air - Clean Jobs Act (Proceeding No. 10M-245E), the early retirement of Craig was approved in 2016 Depreciation Rate Case (Proceeding No. 16A-0231E), and the early retirement of Comanche Units 1 and 2 were approved in the Accelerated Depreciation/RESA Reduction Case (Proceeding No. 17A-0797E);

- 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 electric fuel and purchased power costs, 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;

- The Pre-Paid Pension Asset balance and related ADIT is included in rate base;

- The retiree medical balance associated with Financial Accounting Standard 106, "Employers' Accounting for Postretirement Benefits Other than Pensions", is included in rate base;

- Deductions from rate base include customer deposits, and customer advances for construction;

Revenue

- Retail base rate revenue does not include revenues expected to be billed through various recovery mechanisms: ECA, PCCA, DSMCA, TCA, Interruptible Service Option Credit ("ISOC"), CACJA, and Renewable Energy Standard Adjustment ("RESA"). Any costs or incentives recovered through these recovery mechanisms are eliminated from the cost of service;

- The revenues 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;

- Electric demand and energy sales are normalized for weather;

- Adjustments are made to Other Electric Revenue to exclude revenues related to residential late payments, rate refunds, Quality of Service Plan bill credits, Demand-Side Management ("DSM") incentives, Joint Operating Agreement revenues, wholesale related transmission and ancillary service revenues, unbilled transmission revenues, ISOC, deferred fuel revenues, Hybrid Renewable Energy Credits, Medical Exemption revenue, customer data report revenue, and discounts given to certain contract customers under C.R.S. §40-3-104.3(2)(a);

- Residential late payment revenues are excluded from the cost of service calculation, as these revenues are donated to Energy Outreach Colorado;

- Include an adjustment to other Electric Revenue for the partial rate recovery of the Southeast Water Rights;

Fuel, Purchased Power and O&M Expenses

- Fuel expenses, purchased power energy and demand expenses, and purchased wheeling expenses are eliminated from the determination of revenue requirements;

- Reclassify Fuel Handling and Transportation expenses recorded in fuel accounts that are recovered in base rates;

- Labor expenses recorded in FERC Account 501 and 547 are reclassified from fuel expenses to Production O&M expense;

- Include adjustments to O&M expense for known and measurable changes occurring both in the test period (in-period adjustments), and outside the test period (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 period;

- O&M expense that are not recovered through base rates, but rather recovered through other recovery mechanisms are eliminated;

- O&M expense associated with incremental wholesale sales are not included in the cost of service;

- Margins associated with the Company's trading activities that are returned to customers through the ECA mechanism are eliminated;

- 50 percent of the retail jurisdiction portion of O&M expenses associated with the Company's energy trading activities are excluded from the cost of service study;

- Amortization of the acquisition costs associated with the Company's investment in the Blue Spruce Energy Center and the Rocky Mountain Energy Center generating stations (jointly, the "Calpine Facilities") is included in Production O&M expense. The acquisition costs are being amortized over 10 years beginning in January 1, 2011;

- Include merit increases for bargaining unit and non-bargaining unit employees that occurred during the test period and within one year after the end of the test period, 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 included in base rates at the level of $89,263,631 as set in the 2009 Rate Case;

- 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;

- Executive long-term incentive pay, net of the portion that is attributable to environmental goals is excluded from the cost of service;

- Discretionary pay is excluded from the cost of service;

- Amounts paid to employees for their Annual Incentive Pay ("AIP") above 100 percent of target are excluded from the cost of service;

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

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

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

- Cost allocation between regulated and non-regulated business activities is based on the Cost Allocation and Assignment Manual and the Fully Distributed Cost Allocation Study filed in this rate review as sponsored by Company witness Ms. Melissa L. Schmidt;

Depreciation and Amortization Expense

- 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 Pre-Funded AFUDC associated with Comanche 3 and TCA CWIP included in rate base without an AFUDC offset to earnings;

- Include amortization of Excess AFUDC associated with CACJA projects;

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

- Property taxes incurred in 2015 through 2019 that were above the level of property taxes included in the base rates from the 2014 Electric Rate Case have been deferred, and are being amortized over five years effective with rates from this rate review;

- Adjust property taxes for changes to property taxes that are expected to occur one year following the test period;

- Adjust property taxes allocated to the electric department based on the plant balances on the plant balances from the prior calendar year;

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

<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;

- 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 and the amortization of Investment Tax Credits are included in total income tax expense;

- Federal Production Tax Credits are eliminated from the income tax calculation;

<u>AFUDC Offset to Earnings</u>

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

- Annualizing the AFUDC addition to earnings because rate base was calculated using year-end balances;

Gains on the Disposition of Emission Credits

- Gains on the disposition of emission credits due to the Department of Energy auction are included as a credit to the cost of service;

Capital Structure

- Capital structure is based on actual book year-end balances;

- 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;

- 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;

Jurisdictional Allocation Factors and Direct Assignments

- The allocation between the retail and wholesale jurisdictions is performed on a line-by-line basis for both rate base and earnings based on either a fundamental allocator or a derived allocator. The fundamental allocators are either demand or energy related. The demand fundamental allocation factors are calculated based on the calendar year 12 Coincident-Peak method; and

- Direct assignment of any costs of service item to either retail or the wholesale jurisdiction is identified.

I have prepared Attachment DAB-6 that summarizes the regulatory principles and adjustments included in the HTY cost of service study presented in this rate review, including identifying the Company witnesses that support those adjustments.

Q. WERE THERE ANY REGULATORY AMORTIZATIONS APPROVED BY THE COMMISSION IN THE 2014 ELECTRIC RATE CASE THAT ARE NOT INCLUDED IN THE COST OF SERVICE STUDY PRESENTED IN THIS RATE REVIEW?

A. Yes, there were several regulatory amortizations approved in the 2014 Electric Rate Case that expired on December 31, 2017. Also, one additional Commission-approved amortization from prior rate cases has also expired. The regulatory amortizations from the 2014 Electric Rate Case that expired on December 31, 2017 include:

- Rate Case expenses from the 2014 Electric Rate case;
- Vegetation management costs related to the Mountain Pine Beetle ("MPB") infestation incurred from January 1, 2013 through December 31, 2014 above or below the $6 million in base rates; and
- Property Tax expenses deferred during 2012 through 2014 that were calculated in accordance with the Settlement Agreement entered into in the 2011 Rate Case.

The other regulatory amortization approved by the Commission in prior proceedings that have also expired is the gain on sale of steel rail cars. In Proceeding No. 06S-034EG (the "2006 Rate Case"), the Commission approved the amortization of a gain on the sale of steel railcars, net of actual one-time 2006 costs over 10 years, which expired December 31, 2016. As discussed later in my Direct Testimony, the amortizations that have expired have not been included in the HTY in this rate review.

Q. ARE THERE ANY REGULATORY PRINCIPLES OR ADJUSTMENTS THAT WERE IN THE SETTLEMENT AGREEMENT APPROVED BY THE COMMISSION IN THE 2014 ELECTRIC RATE CASE THAT HAVE NOT BEEN INCLUDED IN THIS RATE REVIEW THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. First, the Company agreed to two principles related to the Metro Ash Disposal Site, located in Bennett, Colorado. In the event that Public Service sells this property in the future, Public Service will be entitled to retain 100 percent of any net proceeds or losses realized from such sale, and Public Service will not include the property as plant held for future use ("PHFU") in any future electric rate cases. In 2015, the Company transferred this asset from Account 105, PHFU, to Account 121, Non-Utility Property, and has not included this asset in rate base in the 2018 HTY in this rate review.

Second, in the 2014 Electric Rate Case, the Company had included the lease expense associated with the Dark Fiber assets in the filed cost of service. Prior to 2018, the Company had leased these Dark Fiber assets from an affiliate New Century Energy Communications, Inc. ("NCEC"), as approved by the Commission in Proceeding No. 98A-262EG. In late 2017, these assets were transferred from NCEC to Public Service, ending the lease. Therefore, there are no lease expenses included in the 2018 HTY in this rate review.

Third, an adjustment was made in the 2014 Electric Rate Case to eliminate the Ponnequin wind farm from the Test Year, as these assets were recovered through the RESA and ECA. The Ponnequin wind farm was retired on the books at the end of 2015. Therefore, there is no adjustment to plant in-service and plant-related costs needed in this rate review.

Finally, as discussed by Company witness Ms. Trammell, there were three adjustments identified in the 2014 Rate Case Settlement Agreement that the Company committed to making in its 2017 Rate Case. The Company is not making these adjustments in this rate review: 1) capping AIP at 15 percent; 2) adjusting pension expense for AIP above target; and 3) managing the equity component of the capital structure to be lower than 56 percent. These commitments were met in the 2017 Rate Case.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE TREATMENT OF ANY OF ITS COSTS OR REVENUES IN THIS PROCEEDING FROM THE WAY IT HAS TREATED SUCH COSTS IN THE COST OF SERVICE PREPARED FOR PRIOR RATE CASES?

A. Yes. First, the 2018 HTY presented in this rate review includes changes to the treatment of the prepaid pension asset in rate base and requests that other regulatory assets and liabilities be included in rate base related to employee benefits, including; Financial Accounting Standard No. 112, Accounting for Postemployment Benefits ("FAS 112")[5], and non-qualified pension. The Company proposes to earn a full return at the WACC on the balance of

[5] 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.

over/under funding on all pension and other postemployment benefits. There is one additional regulatory asset that has been included in rate base and earning a full return at the WACC since the 2011 Rate Case, the Regulatory Liability associated with Financial Accounting Standard No. 106, Accounting for Postretirement Benefits Other than Pensions ("FAS 106")[6]. In addition, the Prepaid Pension Asset is being presented in rate base as the gross balance, and not netting the balance with the pension-related ADIT, as has been done in prior rate cases. This is only a presentation change, as the pension-related ADIT is included with the other ADIT balances in rate base. The change in the treatment of the prepaid pension asset and including other employee benefit regulatory assets and liabilities in rate base is explained in more detail in the testimony of Company witness Mr. Schrubbe.

Second, the Company proposes to include the unamortized balances of regulatory assets in rate base and earn a full return at the WACC. These regulatory assets include:

- Rate Case expenses;
- Innovative Clean Technology projects;
- Pension expenses;
- Property Tax expense;
- AGIS CPCN costs; and
- Gain on Sale of Assets.

Third, the Company has presented the 2018 HTY using the year-end rate base methodology. To provide a better match for year-end rate base, the

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

Company proposes to increase the 2018 HTY base revenue to account for the level of customers at year-end, as discussed later in my testimony.

Fourth, as discussed by Company witness Ms. Trammell, for depreciable assets that have been included in the Company's regulated rate base, Public Service proposes that the net gains and losses be allocated between customers and the Company based on the percentage of the depreciable asset that has been depreciated, with the depreciated percentage portion of the gain or loss allocated to customers and the remainder to the Company.

Fifth, as discussed by Company witness Ms. Trammell, the Company is proposing to not share with customers the oil and gas royalty revenues.

Finally, as discussed by Company witness Ms. Soong, the Company is proposing to use the actual capital structure as of March 31, 2019, instead of the actual 2018 year-end capital structure.

Q. WHY IS THIS 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 decision to defer the costs. These costs remain in the regulatory asset, without appropriate 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 to the shareholder until the cost is recovered in the period amortized to compensate for the carrying costs of 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. HAVE THERE BEEN ANY COMMISSION DECISIONS OR APPLICATIONS FILED BY THE COMPANY SINCE THE LAST RATE CASE THAT IMPACT THE REVENUE REQUIREMENT FILED IN THIS RATE REVIEW?

A. Yes, there are several cases since the 2014 Rate Case that impact the revenue requirement filed in this rate review. First, as discussed by Company witness Mr. Jack Ihle, the Commission approved a Settlement Agreement in the Company's application to invest in two new Innovative Clean Technology ("ICT") projects, Proceeding No. 15A-0847E. The Company is proposing to amortize the deferred capital and O&M costs associated with these projects in the HTY in this rate review, and earn a full return at the WACC on the unamortized balance.

Second, as discussed by Company witness Ms. Wold, the Commission approved the Company's application for initial depreciation rates for Cherokee Electric Generating Units 5, 6 and 7, Proceeding No. 15A-0916E. However, as clarified by the Commission in its decision in that proceeding, Decision No. C15-1351, the approval of the initial depreciation rate for Cherokee Units 5, 6 and 7 was to have no precedential effect in the 2016 depreciation filing. The depreciation rates approved in the 2016 depreciation filing settlement, Proceeding No. 16A-0231E ("Depreciation Case"), are used in this rate proceeding[7]. Also, under the terms of the settlement agreement, the Company is allowed to include incremental outside consultant and legal expenses incurred by the Company in preparing and defending the 2016 Depreciation Case in the next Electric Phase I rate case.

Third, the Commission approved a Settlement in the Company's 2016 Phase II Rate Case, Proceeding No. 16AL-0048E, which included two agreements to be addressed in the next Phase I electric rate case. First, the Settling Parties agreed that the Company will assign distribution load dispatching costs to all distribution functions rather than to only distribution substations, and investigate the need for related changes. Second, the Settling Parties agreed that the Company will be able to defer its actual rate case expenses associated with the 2016 Phase II Rate Case and any additional programming and billing costs of implementing the Residential Demand-Time Differentiated Rates and Residential Energy Time-of-Use Rates , and will include these costs for recovery in the next Electric Phase I rate case. All actual expenses will be deemed eligible for recovery. The Company will defer and track the actual costs in an accounting asset without interest until they are included for recovery in the next

[7] As agreed to in the 2014 Electric Rate Case Settlement, the Company is allowed to ask for recovery of the incremental outside consultant and legal expenses incurred by the Company in preparing and defending the 2016 Depreciation Case. These expenses are included in the rate case expenses requested in this rate review.

Electric Phase I rate case. I discuss how the Company has addressed these two agreements later in my Direct Testimony.

Fourth, the Commission approved a Settlement agreement in the Company's application of its Solar*Connect program that was renamed Renewable*Connect, Proceeding No. 16A-0055E. In that Settlement Agreement, the customer charge billed to Renewable*Connect customers includes the underlying solar resource costs, the integration costs, and program administration costs. The program administration costs have been eliminated from base rates in this rate review, as discussed later in my Direct Testimony.

Fifth, the Commission approved a Settlement Agreement in the Company's application for approval of the 600 MW Rush Creek Wind Project (Proceeding No. 16A-0117E), which allows cost recovery through the ECA and RESA until such time as the Company files a base rate case following the commercial operation date of the project. The commercial operation date of the project was December 7, 2018. Therefore, as I have mentioned previously, Rush Creek is being rolled-into base rates in this rate review.

Sixth, as I noted earlier and further discussed by Company witness Ms. Wold, the Commission approved the Settlement Agreement in the Company's application for approval of revised depreciation rates for its Electric and Common Utility Plant and the amortization of regulatory assets associated with retired electric generating units in the Depreciation Case. These approved depreciation rates and the approved amortization periods for the retired generating units are the basis for the depreciation and amortization expense in the 2018 HTY filed in this rate review.

Seventh, the Commission approved the Company's application in Proceeding No. 16A-0276E to implement a JDA between Public Service, Black Hills Colorado Electric Utility Company, LP and Platte River Power Authority. In compliance with the approval, the Company is providing information in this rate review demonstrating the revenues from the management fees are in excess of the costs associated with implementing the JDA, as I discuss later in my Direct Testimony.

Eighth, the Company filed two applications requesting approval to sell land at the Barker Substation site (Proceeding No. 15A-0779E) and at the Cameo Generating Station site (Proceeding No. 16A-0459E). In both of these cases, the Commission deferred action on the recognition of the gain/loss attributable to the transaction until the next general electric rate case. Company witness Ms. Trammell provides Direct Testimony supporting the proposed treatment of the gain/loss in this rate review.

Ninth, as discussed by Company witnesses Mr. Harkness and Mr. Nickell, the Commission approved a Settlement Agreement filed in the Company's application for a Certificate of Public Convenience and Necessity ("CPCN") to build distribution grid enhancements, including advanced metering and Integrated Volt-Var Optimization ("IVVO") infrastructure, known as the Advanced Grid Intelligence and Security projects ("AGIS CPCN Projects"), Proceeding No.

16A-0588E. As discussed by Company witness Ms. Trammell, the Company has included the capital and O&M expenses associated with all the AGIS projects expected to be in service before the end of 2019. I provide additional detail on the AGIS adjustments later in my Direct Testimony.

Tenth, as discussed by Company witness Ms. Wold, the Commission approved a Settlement Agreement in the Company's application for Accelerated Depreciation/ RESA Reduction case associated with the Colorado Energy Plan, which included the early plant retirement of Comanche Units 1 and 2, Proceeding No. 17A-0797E. The Regulatory Asset and corresponding Accumulated Reserve for Depreciation were recorded on our books in 2018, and have been included in rate base in this rate review, netting to a zero impact to rate base.

Eleventh, the Commission approved a Settlement Agreement to incorporate the impacts of the TCJA in electric rates for 2018 and 2019, Proceeding No. 18M-0074EG. Along with base rate revenue reductions beginning June 1, 2018 through December 31, 2019, the Settlement Agreement allowed for the recovery of the Legacy Pre-Paid Pension Asset of $59.2 million during 2018, and $33.7 million during 2019, until new rates take effect from the Company's next filed rate case. These reductions to the Legacy Pre-Paid Pension Asset are discussed by Company witness Mr. Schrubbe, and are included in the rate base balance presented in this rate review. The impacts of the TCJA are incorporated into the Cost of Service presented in this rate review as discussed later in my Direct Testimony.

Finally, the Commission approved the Company's application authorizing the sale of street lighting facilities to the City of Golden in Proceeding No. 18A-0883A. The Company has removed these assets from rate base, eliminated related O&M expenses and revenues associated with these assets from this rate review, as discussed later in my Direct Testimony.

Q. HAS THE COMPANY MADE ANY NEW ADJUSTMENTS TO THE 2018 HTY PRESENTED IN THIS RATE REVIEW OTHER THAN THOSE APPROVED BY THE COMMISSION IN PRIOR RATE CASES?

A. Yes. The Company is proposing several new adjustments to the HTY as well as application of new regulatory principles in this rate review. First, as discussed by Company witness Ms. Trammell, the Company is proposing to adjust Gross Plant in Service and plant-related costs for certain plant additions in 2019 that are expected to be in-service before the end of 2019, including the AGIS projects. As discussed later in my Direct Testimony, the Company is not including plant additions related to transmission projects that will be recovered through the TCA or distribution projects that are revenue-producing in nature. The Company's business area witnesses support these capital additions and the expected in-service dates in their Direct Testimonies. Second, the Company is making several adjustments for costs expected to be incurred in 2019 that are not in the 2018 HTY. As discussed by Company witnesses Mr. Nickell and Ms. Paoletti, the Company is proposing capital and O&M expense adjustments for Wildfire

Mitigation. Additional details of these adjustments are provided in the sections of my Direct Testimony below addressing rate base and O&M.

IV. RATE BASE

Q. WHAT METHOD OF DETERMINING RATE BASE HAVE YOU USED?

A. The cost of service rate base for the 2018 HTY was calculated using a year-end balance methodology for all items except the following: (1) coal, oil and natural gas used for electric generation inventory balances were calculated using the average of the 12 monthly average balances; (2) materials and supplies inventory balances and non-plant rate base items were calculated using a 13-month average balance methodology; and (3) Cash Working Capital. Cash Working Capital is 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. 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 10 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 Rate Case, Proceeding No. 15AL-0135G and continuing with the 2017 Gas Rate Case, Proceeding

No. 17AL-0363G, the Commission ordered that rate base be calculated using a 13-month average. In the 2015 Gas Rate Case, 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, only one-quarter of the Company's investment in this asset would be included in rate base and earning a return if the 13-month average was used[8].

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

A. Where a 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 plant investment may be moved to plant in service throughout the year and the year-end plant balance accounts for accumulated depreciations as well as other plant impacts. As discussed by several of the Company's witnesses, the Company is making significant investments in the Electric Department. By using year-end rate base for the HTY, Public Service begins to capture some of these significant investments, but not all.

A previously mentioned, the Company is proposing in this rate review to make an adjustment to include the 2019 capital additions in rate base to capture these significant investments, and to include rate base balances that are closer to the time when rates are in effect. The Company has requested that base rates

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

from this rate review become effective January 1, 2020. The Company's rate base balances presented in this rate review are representative of the rate base level when rates are effective and is much closer than even the year-end balances used in the HTY, which are as of December 31, 2018.

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 Rate Case Proceeding No. 15AL-0135G, and the long-standing use of year-end rate base for HTYs by the Commission before that case support the use of year-end rate base. Nevertheless, setting aside this disagreement, the Commission explicitly noted that earnings attrition would serve as evidence of "extraordinary conditions" that would support the use of year-end rate base. The Company Electric Department's revenue requirements have grown on average over 1.71 percent per year since 2013 as reflected in the table below.

Table DAB-D-3

Year	Revenue Requirements[9]
2013	$1.559 B
2014	$1.590 B
2015	$1.633 B
2016	$1.679 B
2017	$1.713 B
2018	$1.698 B
6 Yr. CAGR	1.71 %

[9] Revenue Requirements numbers from Public Service's Annual Report to the Commission and does not include capital recovered through the CACJA Rider or Rush Creek recovered through the ECA.

This increase is primarily due to growth in plant additions and other plant-related costs, e.g., depreciation expense and related income tax expense, partially offset by higher ADIT due to bonus depreciation and TCJA impacts beginning in 2018. The O&M expense over this period has declined. The Company's Electric Department costs of providing service is increasing, and without revenue growth during this period (2013 – 2018), on average, the Company would have been substantially under-earning and experiencing earnings attrition.

Since the 2014 Rate Case, and the resulting decrease in base rates from that case implemented in early 2015, the Company's earned return on equity as reported in its Annual Report to the Commission (also known as the Appendix A), has declined, as compared to our currently authorized return on equity of 9.83 percent, as reflected in the table below.

Table DAB-D-4

	2015	***2016***	***2017***	***2018***
Earned ROE[10]	9.96%	9.27%	8.81%	8.75%
Authorized ROE	9.83%	9.83%	9.83%	9.83%

With the growth in capital expenditures in 2019 discussed by several Company witnesses in this rate review, setting rates based on an HTY and using a 13-month average rate base methodology will likely result in the Company being in an under-

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

earning position. Therefore, the year-end rate base methodology should be used for developing the HTY revenue requirement.

Q. ARE THERE OTHER REASONS THAT SUPPORT THE USE OF YEAR-END RATE BASE?

A. Yes. There are two other reasons the Commission should use the year-end rate base methodology to set base rates in this rate review. First, using a 13-month average rate base reaches too far into the past and year-end rate base is a better match to the period that rates will be effective. The 13-month average is essentially using a June 30, 2018 rate base level, when rates will be effective beginning January 1, 2020 – a year and a half later. The year-end rate base is a better match of current costs to current revenues, when rates are in effect, which is sometimes referred to as the "matching principle." There is a well-recognized principle of regulatory matching between investments, revenues and expenses in a test year. In a base rate case, I do not view the matching principle as applicable within the walls of the test year, i.e., between January 1, 2018 and December 31, 2018. I believe the matching principle should be viewed and applied more holistically. In this proceeding, we are requesting to set rates with an effective date of January 1, 2020. This is the date we should be looking at for purposes of matching, not the months within the walls of the test year itself. In other words, where a 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 plant investment may be moved to plant in service throughout the year and the year-end plant balance accounts for accumulated depreciations as well as other plant impacts. The rate base used for setting rates is closer in time to the effective date of the rates. By getting these two points in time as close as possible to one another, we have more closely adhered to the matching principle in the HTY rate base context.

Second, the Rush Creek Wind Project was placed in service December 7, 2018. Use of a 13-month average rate base would unfairly include Rush Creek in base rates at a level not equivalent to the level currently being recovered in the ECA. The Rush Creek Wind Project is currently being recovered in 2019 at its full gross plant level at the end of 2019. In any case, Rush Creek should be included in this rate review at the year-end 2018 level; otherwise the Company will unfairly recover a small portion of our investment in this asset if a 13-month average is approved.

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

A. The gross plant in-service, PHFU and CWIP balances included in the HTY cost of service are based on the Company's actual books and records at December 31, 2018.

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

A. The balances presented on Attachment DAB-1, Schedule 100 match the balances presented by Company witness Ms. Wold on Attachment LJW-1, which shows the calculation of the year-end balances for plant in service and accumulated reserve for depreciation and amortization.

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

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 2018 allocation factors were used in the HTY presented in this rate review.

Q. WHAT ADJUSTMENTS DID YOU MAKE TO PLANT IN-SERVICE BALANCES THAT FOLLOW PREVIOUSLY ESTABLISHED RATEMAKING PRINCIPLES?

A. Several adjustments were made to plant in-service balances to follow previously established ratemaking principles. The adjustments made to the HTY on Attachment DAB-1 include:

- functionalize the intangible plant in-service balances in order to properly allocate these costs to the correct jurisdiction;

- eliminate the investment in the Pawnee turbine blade project that exceeded the Commission-ordered expenditure cap from the plant in-service balance and plant-related cost of service items (Schedule 129); and
- eliminate 50 percent of the investment in specific distribution substations serving Holy Cross Electric Association, Inc. from the plant in-service balance and plant-related cost of service items (Schedule 125).

In addition to the plant in-service adjustments, adjustments also were made to plant-related cost of service items including, accumulated reserve for depreciation, ADIT, depreciation expense, current tax additions and deductions, and deferred income tax expense.

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

A. Yes. First, as discussed by Company witness Ms. Trammell, the Company has made adjustments to the HTY year-end gross plant in-service balances, and plant-related cost of service items to include certain 2019 projected capital additions expected to be in-service by December 31, 2019, including the AGIS and Distribution Wildfire Mitigation projects. Second, an adjustment was made for distribution assets that were in CWIP at the end of 2018 that should have been closed to plant in-service, as discussed by Company witness Ms. Wold. Third, an adjustment was made to transfer AGIS Field Area Network (“FAN”) assets recorded in Plant Held for Future Use at the end of 2018 to plant-in service. These assets are expected to be in-service in 2019. Fourth, adjustments were made to reclassify a common general project related to the AGIS projects to move it out of Common

General plant and move it to Electric General plant. Finally, adjustments were made to remove the gross plant and plant-related costs associated with the street lights that were sold to the City of Golden.

In addition, as previously mentioned, the Company is including the gross plant in-service, plant-related costs, O&M expenses and other costs associated with the CACJA and Rush Creek projects in this rate review, that were not previously included in base rates.

Q. PLEASE DISCUSS THE ADJUSTMENT TO THE 2018 YEAR-END GROSS PLANT IN-SERVICE BALANCES TO INCLUDE CERTAIN 2019 ADDITIONS EXPECTED TO BE IN-SERVICE BEFORE DECEMBER 31, 2019.

A. The Company has made adjustments to the HTY year-end gross plant in-service balances, and plant-related cost of service items to include certain 2019 projected capital additions expected to be in-service by December 31, 2019, including the AGIS and the Distribution Wildfire Mitigation (Distribution portion) projects. The Company has not included any transmission projects that are recovered through the TCA or any distribution projects that are revenue producing in nature, as the Company should generate future revenue for these distribution projects. Company witness Mr. Nickell discusses these projects in more detail in his testimony. A large portion of the 2019 projected capital additions included in this rate review were spent in 2018 and reflected in actual 2018 year-end CWIP balances. Therefore, in order to not double count projects in the plant in-service balances and the CWIP balances presented in this rate review, an adjustment was made to remove all of the 2018 year-end CWIP balances in rate base. I discuss the CWIP adjustment later in my Direct Testimony. The 2019 projected capital additions, expected in-service dates, along with other relevant information, were used in the development of adjustments, as discussed by Company witness Ms. Wold and supported by the business area Company witnesses. In addition, included in the adjustments to reflect the 2019 projected capital additions and plant-related costs, the Company has included the 2019 level of Accumulated Reserve for Depreciation and ADIT associated with the Rush Creek Wind Project and the CACJA assets, since the balance of these plant-related costs at the end of 2018 is not the expected level when rates are expected to be effective from this rate review. The adjustments made to gross plant, CWIP and other plant-related items, are shown on Attachment DAB-1, Schedules 135 (Distribution Wildfire Mitigation), 137 (AGIS), and 140 (2019 capital additions).

Q. HAS THE COMMISSION PREVIOUSLY ALLOWED ADJUSTMENTS TO PLANT IN-SERVICE BALANCES AFTER THE END OF A HTY PERIOD?

A. Yes. In the 2009 Rate Case, the Commission approved a Settlement Agreement that included forecasted incremental investments in distribution plant after the end of the 2018 HTY period. The Commission approved adding incremental investments in distribution to the 2008 HTY rate base through June 20, 2009.[11] In addition, the Commission approved several adjustments to the 2008 HTY for known changes in rate base that occurred after the end of the 2008 HTY, including

[11] 2009 Rate Case, Decision No. C09-1446, ¶51.

rate base adjustments for Comanche 3, Comanche 1 and 2 pollution control equipment, transmission upgrades for Comanche 3, and Fort St. Vrain Units 5 and 6.

Q. WHAT IS THE COMPANY'S JUSTIFICATION FOR MAKING ADJUSTMENTS TO THE HTY TO INCLUDE PLANT ADDITIONS THROUGH THE END OF 2019?

A. The Company is asking to include certain 2019 plant additions in this rate review to help reduce, but not eliminate, the regulatory lag caused by setting rates using an HTY. The adjustment is also consistent with the ratemaking principle that the purpose of a test year with *pro forma* adjustments is to develop a cost of service that is at the level of costs the utility is expected to experience when rates are effective. The adjustment the Company is proposing in this case is to include plant additions expected to be in-service before January 1, 2020. As previously discussed, the Company is requesting that rates from this rate review become effective January 1, 2020, and if the HTY is approved based on a year-end rate base methodology, new rates will be based on net plant as of the end of December 2018, and recovery will begin 12 months after the assets have been providing utility service to our customers, on the effective date of rates from this rate review, expected January 1, 2020. Using a 13-month average rate base methodology adds another six months to this lag in recovery, or 18 months. Even with the Company's adjustment to include the 2019 capital additions in this rate review, there will be capital additions in 2020 that are not captured in the rates set in this rate review.

The adjustment in this rate review is for assets that are expected to be placed in service during 2019, as discussed by several Company witnesses, and similar to the 2009 Rate Case, the Commission has allowed adjustments to an HTY for changes in rate base that occur before and after the end of an HTY period. The 2019 plant additions, net of retirements can be summarized by the following functions:

Table DAB-D-5

2019 Net Plant Additions by Function	
Hydro Production	$ 1,381,637
Other Production	$ 36,891,202
Steam Production	$ 20,923,444
Total Production	$ 59,196,283
Transmission	$ 888,433
Distribution	$ 255,358,294
Electric General & Intangible	$ 168,260,342
Common General & Intangible[12]	$ 109,277,052
Total	$ 592,980,404

In addition to the adjustments to gross plant and plant-related costs, as discussed by Company witness Ms. Naomi Koch, the Company is making an adjustment to property taxes to reflect the 2019 level of costs, as discussed later in my Direct Testimony.

[12] The Common General and Common Intangible 2019 Plant Additions are total Company numbers. The electric portion is approximately 71 percent.

Q. PLEASE DESCRIBE THE ADJUSTMENT MADE TO RECLASSIFY THE INVESTMENT ASSOCIATED WITH THE AGIS PROJECTS THAT WAS CLASSIFIED AS A COMMON GENERAL ASSET THAT HAS BEEN ADDED TO THE COST OF SERVICE STUDY PRESENTED IN THIS RATE REVIEW.

A. The FAN component of the AGIS projects is classified as a common general asset. This is the appropriate classification because this component will benefit the Public Service Electric Department and the Company's electric customers, as well as the gas side of the business and gas customers. Benefit to the gas department and gas customers will not occur when this asset is initially put in service. Therefore the Company has added 100 percent of this investment to the Electric Department cost of service study presented in this rate review. This approach is consistent with the adjustment made in the 2017 Gas Rate Case, where zero percent of these costs were included in the Gas Department rate base.

Q. WILL THE COMPANY EVER RECLASSIFY THE PLANT-RELATED COST OF SERVICE ITEMS RELATED TO THE COMMON GENERAL FUNCTION?

A. Given that the FAN will benefit electric customers at the outset, we have included this asset as being 100 percent assigned to the electric department in this rate review. However, in a future rate case for the gas side of the business, we may reclassify the FAN component of the AGIS projects as a common general asset and seek recovery at that time, if and when the FAN is used by the Gas Department.

Q. PLEASE DISCUSS THE COSTS OF THE CACJA PROJECTS INCLUDED IN THIS RATE REVIEW.

A. The Commission, in the 2014 Electric Rate Case, approved a CACJA Rider that was implemented in the Company's electric tariffs. To be eligible to be included in the CACJA Rider, a cost must be incurred and associated with a CACJA investment that either has gone into service or will go into service between August 1, 2014 and December 31, 2017. The eligible CACJA projects include: a new natural gas 2X1 Combined Cycle plant including interconnection equipment at Cherokee Station, referred to as Cherokee Units 5, 6 and 7; a selective catalytic reduction ("SCR") and particulate scrubber at Pawnee; and SCR equipment at the Hayden Station on Units 1 and 2. The gross plant in-service and plant-related costs, and the variable non-fuel O&M expenses associated with the CACJA projects were recovered through the CACJA Rider. As discussed by Company witness Ms. Trammell, it was the Company's intent to roll these costs into base rates soon after all the assets were placed in-service. All of the CACJA projects were completed and placed in-service before the end of 2017. The CACJA plant in-service balances are included in this rate review without adjustment. As previously mentioned, adjustments were made to Accumulated Reserve for Depreciation and ADIT to reflect the level of costs of the CACJA projects through 2019 in this rate review.

Q. PLEASE DISCUSS THE COSTS OF THE RUSH CREEK WIND PROJECT INCLUDED IN THIS RATE REVIEW.

A. As previously discussed, the Commission approved the Company's application to build the Rush Creek Wind Project, Proceeding No. 16A-00117E. The Rush Creek Wind Project consist of two wind development areas – Rush Creek I and Rush Creek II – that were constructed as one project with a commercial operation date of December 7, 2018, and associated transmission facilities including a 345 kV generation intertie to interconnect the Rush Creek Wind Project to the grid. The gross plant in-service and plant-related costs, and the O&M expenses associated with these assets were to be recovered through the ECA and RESA until such time as the Company files a base rate case following the commercial operation date of the project. This rate review is the next electric case after the commercial operation date, and the Company is proposing to roll the costs of the Rush Creek Wind Project into base rates in this rate review. The Company has included the year-end gross plant in-service associated with Rush Creek in this rate review. As previously mentioned, adjustments were made to Accumulated Reserve for Depreciation and ADIT to reflect the level of costs of the Rush Creek Wind Project through 2019 in this rate review. In addition, as discussed later in my Direct Testimony, the Rush Creek O&M expenses and depreciation expenses in the book amounts do not reflect a full year of costs, and have been annualized in the 2018 HTY.

Q. ARE THERE OTHER RUSH CREEK COSTS INCLUDED IN THE 2018 HTY IN THIS RATE REVIEW THAT ARE NOT CURRENTLY BEING RECOVERED IN THE ECA?

A. Yes. As identified in Proceeding No. 16A-0117E, property taxes and property insurance costs are incurred on a total Company basis. Therefore, the Company recovers these costs through base rates, as opposed to through project-specific adjustment clause mechanisms. Property taxes and property insurance associated with the Rush Creek Wind Project are not currently recovered through the ECA, and are included in the 2018 HTY in this rate review. Company witness Ms. Koch discusses the adjustment to the 2018 HTY for Rush Creek property taxes. The Rush Creek property insurance is already included in the per book property insurance expense; therefore, no additional adjustment to the per book balances was made in this rate review. In addition to property taxes and property insurance, any deferred tax asset associated with Rush Creek Federal Production PTCs are also not recovered through the ECA, and will be recovered in base rates. I will discuss the deferred tax asset associated with PTCs below.

Q. IS THERE A DEFERRED TAX ASSET INCLUDED IN RATE BASE IN THIS RATE REVIEW ASSOCIATED RUSH CREEK PTCS?

A. No. As previously mentioned, Rush Creek Wind Project will generate PTCs, which will be credited to customers through the ECA. If Public Service is in a Federal Tax NOL position, the Company will not be able to use the PTCs in the current year, which will result in a Deferred Tax Asset being generated. The Company is currently not in a NOL tax position in the 2018 HTY, therefore there is no deferred tax asset in rate base associated with the Rush Creek PTCs in this rate review. As this rate review proceeds, it should be noted that any change in the revenues, expenses or capital structure will cause the income tax calculation to be changed. and could impact the Company's NOL position. This could in turn affect the timing of the PTC Deferred Tax Asset being generated and added to rate base, and the Company will update the rate review accordingly if this is the case. In any event, before the final revenue requirements is determined in this rate review, these calculations need to be performed.

Q. PLEASE DISCUSS THE AGIS PROJECTS COST IN THE 2018 HTY.

A. As discussed by Company witnesses Mr. Nickell and Mr. Harkness, the Company has made adjustments to include AGIS in the HTY at the year-end December 2019 level. Adjustments have been made in the 2018 HTY to reach forward and include the plant in-service and plant-related costs associated with the capital expected to be in service before the end of 2019, as shown on Attachment DAB-1, Schedule 137. In addition, at the end of 2018, there is a CWIP balance associated with AGIS costs. A portion of this balance is expected to be place into service before the end of the 2019 and was included in the plant-in-service adjustment described above. It is not appropriate to include the year-end CWIP balance associated with AGIS in the HTY cost of service since these amounts are captured in the forward-looking plant in-service adjustment. Therefore, adjustments were made to the HTY to eliminate the CWIP.

Q. PLEASE DESCRIBE THE ADJUSTMENTS MADE TO THE ACCUMULATED RESERVE FOR DEPRECIATION AND AMORTIZATION BALANCE.

A. The adjustments to the accumulated reserve for depreciation and amortization are related to plant in-service adjustments that have already been discussed earlier in my testimony. With the adjustment to include the 2019 Plant Additions in this rate review, the Company has made an adjustment to the accumulated reserve for depreciation and depreciation expense that will occur during 2019 based on the Company's current depreciation rates. Also, as discussed by Company witness Ms. Wold, the Company is including the impact of the Commission-approved new depreciation rates from the 2016 Depreciation Case in this rate review. As a result, the Company has included a full year of depreciation expense resulting from these new depreciation rates in the 2018 HTY. No adjustment was made to the accumulated reserve for depreciation balance for the 2018 HTY, because the Commission has traditionally not allowed this type of forward-looking adjustment to rate base when using an HTY cost of service. The change in the depreciation rates will not be effective until 2020, with the effective date of base rates in this rate review, which is also when the accumulated reserve for depreciation balance will be changed. The adjustment to 2018 HTY cost of service depreciation expense for the proposed depreciation rates are shown on Attachment DAB-1, Schedule 232.

Q. PLEASE DESCRIBE THE REGULATORY ASSETS ASSOCIATED WITH EARLY PLANT RETIREMENTS AND UN-RECOVERED REMOVAL COSTS THAT HAVE BEEN INCLUDED IN RATE BASE IN THIS RATE REVIEW.

A. The regulatory assets included in rate base in this rate review are associated with the early plant retirements and the un-recovered removal costs associated with several generating facilities. Specifically, the regulatory assets are associated with Cameo Units 1 and 2, Arapahoe Units 1 through 4, and Zuni Units 1 and 2, which were approved in the 2009 Rate Case, the generating facilities subject to decommissioning pursuant to the Company's compliance obligations under the CACJA, in Proceeding No. 10M-245E, (Cherokee Units 1, 2, 3 and 4, and Valmont Unit 5), and Craig Unit 1 were approved in the 2016 Depreciation Rate Case, and Comanche Units 1 and 2 were approved in the AD/RR proceeding.

Q. HOW ARE THE REGULATORY ASSETS ASSOCIATED WITH THE EARLY PLANT RETIREMENTS CALCULATED?

A. The regulatory assets associated with the early plant retirements are equal to any difference between: (a) the level of depreciation expenses for recovery of plant asset costs using the remaining plant lives based on the retirement dates included in the depreciation rates approved in the 2016 Depreciation Case; and (b) the level of depreciation expense using updated or revised remaining lives associated with such plants reflecting the early retirement dates approved by the Commission. The regulatory assets are included in rate base before the plants are retired, however, there is an equivalent associated offset cost reflected in the Accumulated Reserve for Depreciation balance, meaning the net rate base impact is zero.

For most of the early plant retirement regulatory assets, once the plant is retired, the regulatory asset is included in rate base without an offset to the Accumulated Reserve for Depreciation balance, and the Company will earn a return on the unamortized balance. The regulatory asset will be amortized over seven years, consistent with the Commission approved amortization period from the 2016 Depreciation Case. The amortization expense is also included in the cost of service. The exception to this treatment is the regulatory assets associated with Comanche Units 1 and 2. The regulatory assets associated with Comanche Units 1 and 2 will be amortized in compliance with the Commission's approval of the AD/RR proceeding. The regulatory assets associated with the early plant retirements included in the HTY cost of service study are shown on Attachment DAB-1, Schedule 101.

Q. HOW ARE THE REGULATORY ASSETS ASSOCIATED WITH THE UN-RECOVERED REMOVAL COSTS CALCULATED?

A. The regulatory assets associated with the un-recovered removal costs are equal to any difference between: (a) the level of depreciation expense using the removal cost recovered through the base rates as part of the depreciation rates through the date of retirement; and (b) the actual cost of removal incurred by the Company associated with the decommissioning of the plant. The difference in the removal costs can either be a positive difference (an asset) or a negative difference (a liability). If the actual costs are higher than the removal costs included in depreciation rates, the un-recovered removal costs will be a regulatory asset. If the actual costs are lower than the removal costs included in depreciation rates, there is an over collection, and a regulatory liability will be set up. The net regulatory asset associated with the un-recovered removal costs will be amortized over seven years consistent with the early retirement regulatory asset as discussed above. The amortization expense is also included in the cost of service. The regulatory assets associated with the un-recovered removal costs included in the 2018 HTY.

Q. PLEASE DESCRIBE THE ADJUSTMENT MADE TO THE PLANT HELD FOR FUTURE USE BALANCE IN THE 2018 HTY PRESENTED IN THIS RATE REVIEW.

A. The Company made two adjustments to the Plant Held for Future Use ("PHFU") balance in the 2018 HTY. The Company is proposing to continue the current regulatory treatment of the Company's investment in water rights located in Southeastern Colorado ("Southeast Water Rights"), which requires an adjustment to remove the balance of these water rights from FERC Account 105 – PHFU. Also, adjustments were made to PHFU associated with the AGIS FAN project. In 2018, AGIS FAN project was recorded as Common General PHFU. An adjustment was made to reclassify from Common General PHFU to Electric General PHFU, which increases the PHFU balance. Second, an adjustment was made to transfer the Electric General PHFU balance to plant-in service. These assets are expected to be in-service in 2019.

Q. PLEASE DISCUSS THE CURRENT REGULATORY TREATMENT OF THE SOUTHEAST WATER RIGHTS.

A. The regulatory treatment of the Southeast Water Rights was first approved by the Commission in Proceeding No. 93S-001EG, Decision No. C93-1346, dated October 14, 1993, which allowed the Company to continue to include the Southeast Water Rights in rate base at a debt-only return. This treatment was later reaffirmed in the Settlement Agreement approved in Proceeding No. 02S-315EG and again in Paragraph 3.E. of the Settlement Agreement approved in Proceeding No. 11AL-947E. The way the Company implements this regulatory treatment is that the Southeast Water Rights are eliminated from PHFU in Rate Base as shown on Attachment DAB-1, Schedule 130. Then an adjustment is made to include in Miscellaneous Revenue the earnings on the asset using a debt-only return, the calculation is provided on Attachment DAB-1, Schedule 223. In this way, the Southeast Water Rights are treated as if they remain in rate base but earn only a debt return as agreed to in the Settlement Agreements.

Q. HOW WAS CWIP TREATED IN THE 2018 HTY PRESENTED IN THIS RATE REVIEW?

A. This Commission has a long-standing regulatory practice of including CWIP in rate base with an AFUDC offset to earnings when using an HTY. However, in this rate review, because the Company is making an adjustment to include 2019 plant additions expected to be in-service before December 31, 2019, and a large portion of the 2018 year-end CWIP balance is included in the 2019 capital adjustment, the

Company is proposing to not include CWIP in rate base and to not include an AFUDC offset to earnings. The Company has eliminated $411.5 million in CWIP from the 2018 HTY. In addition, with the elimination of CWIP in rate base, adjustments were also made to eliminate permanent tax items related to AFUDC equity in the income tax calculation.

Q. PLEASE DISCUSS THE HISTORY OF INCLUDING CWIP IN RATE BASE WITH AN AFUDC OFFSET TO EARNINGS WHEN USING A HTY.

A. The Commission has a long-standing practice of allowing a utility to include CWIP in rate base with an offset to earnings for AFUDC, going back to at least Commission Decision No. 78811, dated October 4, 1971, in Application No. 24900. This practice has been used in prior Company rate cases when a historical test year was used for developing the cost of service, and was adopted by the Commission to compensate the Company, in part, for attrition attributable to growth in plant when a historical test year is used to set rates.

Q. PLEASE DESCRIBE THE BASIS FOR THE BALANCES ASSOCIATED WITH MATERIALS AND SUPPLIES, CUSTOMER DEPOSITS, AND CUSTOMER ADVANCES FOR CONSTRUCTION INCLUDED IN THE 2018 HTY PRESENTED IN THIS RATE REVIEW.

A. The balances used in the 2018 HTY for materials and supplies (Attachment DAB-1, Schedule 133), customer deposits (Attachment DAB-1, Schedule 230), and customer advances for construction (Attachment DAB-1, Schedule 110) are all based on the actual 13-month average balances during the test period, consistent with Commission precedent.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO THE MATERIALS AND SUPPLIES BALANCE.

A. The Commission has established in previous rate cases that an adjustment should be made to the materials and supplies balance to eliminate a portion that is attributable to capital. This adjustment to the HTY cost of service study is shown on Attachment DAB-1, Schedule 133.

Q. PLEASE DESCRIBE THE BASIS FOR THE FUEL INVENTORY BALANCES INCLUDED IN THE TEST YEAR.

A. The fuel inventory balances (coal, oil and natural gas for electric generation) included in the 2018 HTY were based on the average of the actual 12 monthly average balances during the period ended December 31, 2018, as shown on Attachment DAB-1, Schedule 136. In addition, an adjustment was made to adjust the coal inventory associated with the Craig generating station, a jointly-owned generating station with Tri-State, operated by Tri-State. In early January 2019, we discovered an error in our inventory balance due to receiving information on the coal burns in MMBtus, when our inventory was reported in tons. The coal inventory balance had been built over time, by slightly overstating the monthly coal inventory burn since 2014. An adjustment was made to our weighted average cost of coal back to January 2014, resulting in adjustments to the monthly average balances during 2018, increasing the monthly average balance by approximately $4.2 million, as shown on Attachment DAB-1, Schedule 136.

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 two ICT projects, property taxes, pension expense, rate case expenses, and AGIS that have been deferred as regulatory assets. The Company is requesting to amortize these costs in this rate review, and earn a return on the unamortized balance in rate base. In addition, as discussed later in my Direct Testimony, the Company has recorded a gain on the sale of certain assets that has been deferred as a regulatory liability. The unamortized balances of these regulatory assets and liabilities have been included in rate base in the 2018 HTY. The regulatory assets and liabilities included in rate base are shown on Attachment DAB-1, Schedule 123.

Q. PLEASE DESCRIBE THE BASIS FOR THE PREPAID PENSION ASSET BALANCE INCLUDED IN THE 2018 HTY PRESENTED IN THIS RATE REVIEW.

A. As discussed by Company witness Mr. Schrubbe, the Prepaid Pension Asset is included in rate base in the 2018 HTY presented in this rate review. The Company is proposing to include the Prepaid Pension Asset in rate base and to earn a full return on the balance. 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 rate cases, when the Company presented the net Prepaid Pension Asset. The Company is also proposing to use the 2019 ending balance instead of a 13-month average balance, to capture the reductions in the balance from the TCJA Settlement and the reductions to the balance through 2019 to reflect the amortization of the Legacy Prepaid Pension Asset. The Legacy Prepaid Pension Asset as approved in the Commission's decision in the 2014 Electric Rate Case will be fully amortized in July 2019, however the Company has continued the amortization through 2019 to reduce the Prepaid Pension Asset balance presented in this rate review. The 2018 HTY does not include any amortization of the Legacy Prepaid Pension Asset beginning January 1, 2020. The Prepaid Pension Asset balance is shown on Attachment DAB-1, Schedule 134.

Q. PLEASE DESCRIBE THE RETIREE MEDICAL BALANCES INCLUDED IN THE 2018 HTY PRESENTED IN THIS RATE REVIEW.

A. The retiree medical balance associated with FAS 106, "Employers' Accounting for Postretirement Benefits Other than Pensions," is included in rate base in the 2018 HTY. The 2018 HTY balance is based on the 13-month average through December 31, 2018. The retiree medical balance has been included in rate base since the 2011 Rate Case. As discussed later in my Direct Testimony, an adjustment was made to eliminate the negative retiree medical expenses, which reduces the retiree medical balance in rate base. The Commission approved this same adjustment in the recent 2017 Gas Rate Case. The basis for the retiree medical balance, including the adjustment is discussed more fully by Company witness Mr. Schrubbe, and are shown on Attachment DAB-1, Schedules 114 and 255.

Q. PLEASE DESCRIBE THE POST EMPLOYMENT BENEFIT AND NON-QUALIFIED PENSION LIABILITY BALANCES INCLUDED IN THE 2018 HTY PRESENTED IN THIS RATE REVIEW.

A. As previously mentioned, the Company is requesting approval to include the Regulatory Liabilities associated with the Accounting for Postemployment Benefits, FAS 112, and the non-qualified pension in rate base in this rate review, 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 Attachment DAB-1, Schedules 111 and 112.

Q. 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, Investigation & Suspension ("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. The Company in its next rate case, I&S Docket No. 1116, 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 electric 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, 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 TCJA, utilities are no longer eligible for bonus tax depreciation. As discussed by Company witness Ms. Wold, from January 1, 2018 forward, no bonus depreciation on additions for 2018 and forward has been factored into the calculation of ADIT. I discuss other impacts of the TCJA on ADIT and other components of the cost of service later in my Direct Testimony.

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 HTY presented in this rate review. As shown on Attachment DAB-1, Schedule 104, the Company is not in a NOL position in the HTY. In addition, the Electric Department does not have an accumulated deferred tax asset balance carryforward from prior years.

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

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 IMPACTS OF THE TCJA ON THE AMOUNT OF ADIT IN RATE BASE THAT IS PRESENTED IN THIS RATE REVIEW.

A. As described in more detail by Company witnesses Ms. Wold and Ms. Koch, the TCJA impacts the amount of ADIT in rate base. First, the Company has revalued its accumulated deferred tax assets and liabilities at the 21 percent federal corporate income tax rate and has 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" that will be collected from or returned to customers over time. For purposes of calculating rate base, the excess ADIT is included in rate base because it has not yet been recovered from or returned to customers.

In addition, I have included an annual amount of amortization of the excess ADIT in the income tax calculation as I will describe later in my Direct Testimony. Specifically, I have reduced the excess ADIT in rate base by the amount of annual amortization included in income tax expense. I have done this for both plant-related excess ADIT and non-plant-related excess ADIT that is in rate base. The annual amount of amortization of excess ADIT is shown for plant-related ADIT on Attachment DAB-1, Schedule 126 and for non-plant ADIT on Attachment DAB-1, Schedule 127. The adjustment to reduce excess ADIT has the net effect of slightly increasing rate base.

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 study presented in this rate review. First, there are several adjustments related to the plant adjustments as previously discussed, including the adjustments related to the plant expected to be in-service in 2019. Second, adjustments were also made to reflect the 2019 level of ADIT associated with the Rush Creek Wind Project and the CAJCA projects. 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 electric costs associated with the ECA, 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 review consistent with the underlying rate base items. Details of the adjustments to ADIT balances are shown on Attachment DAB-1, Schedule 115.

Q. ARE THERE ANY ADJUSTMENTS TO ADIT FROM PRIOR RATE CASES THAT ARE NO LONGER APPLICABLE?

A. Yes. In prior rate cases, the Company had included an adjustment to ADIT to include one half (1/2) of the unamortized pre-1971 ITC. This amortization ended in 2016. Therefore, the Company has not included this adjustment to ADIT in the 2018 HTY in this rate review. In addition, as previously discussed, the Company is eliminating CWIP from rate base in this rate review. Therefore, there is no adjustment to the ADIT balance for the interest on the CWIP balance. In prior rate cases, when CWIP is included in rate base in which AFUDC is calculated, there was an adjustment to ADIT for interest on CWIP.

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

A. No.

V. TCJA IMPACTS

Q. PLEASE IDENTIFY THE AREAS IN THE COST OF SERVICE STUDY THAT ARE AFFECTED AS A RESULT OF THE TCJA.

A. The areas of the cost of service study that are affected as a result of including the impacts of the TCJA in the HTY 2018 are rate base and income tax expense.

Q. PLEASE DESCRIBE THE IMPACT TO RATE BASE OF THE TCJA.

A. As previously discussed, the TCJA impacts the ADIT balances presented in this rate review. The TCJA was implemented effective January 1, 2018. The Company has revalued its accumulated deferred tax assets and liabilities at the 21 percent federal corporate income tax rate and has 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” that will be collected from or returned to customers over time. For purposes of calculating rate base, the excess ADIT is included in rate base because it has not yet been recovered from or returned to customers. Due to the TCJA Settlement, the Company has returned two years of the excess ADIT amortization from customers through December 31, 2019. In addition, the Company is including one year of the amortization of the excess ADIT in this rate review in deferred tax expense. Therefore, the excess ADIT balance included in rate base reflects the balance at December 31, 2020.

Q. ARE THERE OTHER EFFECTS ON RATE BASE AS A RESULT OF THE TCJA?

A. Yes. As a result of the changes to federal corporate income tax expense, the cash working capital amounts in rate base are impacted. The amount of cash working capital in the cost of service changes automatically when the dollar amounts of the components of the calculation change.

Q. ARE THERE OTHER RATE BASE ITEMS THAT ARE AFFECTED BY THE TCJA THAT HAVE NOT BEEN INCLUDED IN THE COST OF SERVICE STUDY FILED IN THIS RATE REVIEW?

A. Yes. As discussed by Company witness Ms. Koch, the TCJA changed the NOL deductions that will impact the NOL deferred tax asset in rate base. The NOL deduction is limited to 80 percent of taxable income for losses arising in tax years beginning after December 31, 2017. This is not applicable to this rate review given the Company is not in a NOL tax position in the 2018 HTY.

Q. PLEASE DESCRIBE THE EFFECT OF THE TCJA ON INCOME TAX EXPENSE.

A. The vast majority of the impact of the TCJA to the 2018 HTY revenue requirements occurred in the income tax calculation. First, the federal corporate income tax rate was changed from 35 percent to 21 percent. This change affects the calculation of Public Service's current tax expense, as well as the composite tax rate and the tax gross up factor. Second, I have eliminated the Section 199 Manufacturing Deduction that was eliminated effective January 1, 2018. The

Section 199 Manufacturing Deduction previously reduced the revenue requirement in prior rate cases. This change increases current income tax expense. Third, the deferred tax expense includes an annual amount of amortization of the excess ADIT. Ms. Wold and Ms. Koch discuss the effects of the TCJA on deferred tax expense and the amortization of excess ADIT in more detail. Overall, these changes reduce the net amount of income tax expense included in the revenue requirement.

Q. ARE THERE OTHER EFFECTS OF THE TCJA ON INCOME TAX EXPENSE THAT HAVE NOT BEEN INCLUDED IN THE COST OF SERVICE STUDY FILED IN THIS TCJA DIRECT TESTIMONY?

A. Yes. As discussed by Company witness Ms. Koch, the TCJA changed the deductibility of meals and entertainment expense, lobbying expense, and executive compensation effective January 1, 2018. The majority of executive compensation and all of lobbying are eliminated for electric ratemaking purposes, so this change has little impact on our cost of service study, and the meals and entertainment change will likely increase the revenue requirements, and the effect will be relatively minor. Therefore, I did not incorporate these changes in the cost of service study filed.

VI. CASH WORKING CAPITAL

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 REVIEW IN THE SAME MANNER AS IN PRIOR CASES?

A. Yes.

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

A. Yes. The Company prepared a lead-lag study based on the 12 months ending September 30, 2018, which was used for all the 2018 HTY presented in this rate review. The lead-lag study is presented in two Attachments: (1) Attachment DAB-7 is a summary of the lead-lag study for all components; and (2) Attachment DAB-8 is the detail supporting the study. Attachment DAB-8 is voluminous and being provided as a CD-ROM.

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 REVIEW?

A. The Company used the same statistical sampling method to calculate the lead-lag study in this rate review 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.

Revenue lag parameters

- 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 DAB-7.

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 review:

- Electric coal for steam production;
- Natural gas for other power generation;
- Oil for electric generation;

- Electric purchased power;
- 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 most recent 2014 Rate Case and the 2015 Gas Rate Case[13].

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

A. The Company used statistical sampling to determine the expense lead for the coal for steam production, natural gas for other power generation, purchased power, and non-labor O&M cash working capital expense categories. One hundred

[13] In the recent 2017 Gas Rate Case, long-term debt interest was not included in cash working capital. No parties opposed this treatment.

percent of the invoices and payments were reviewed and service dates gathered for the oil for electric generation, 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.

Q. HOW DID THE COMPANY CALCULATE THE CASH WORKING CAPITAL ASSOCIATED WITH THE FUEL, PURCHASED ENERGY AND PURCHASED CAPACITY COSTS?

A. The Company multiplied the applicable net lead-lag factors by the per-book test period fuel, purchased energy and purchased capacity expenses, instead of the pro forma amounts. Currently, the electric department has no fuel or purchased energy in base rates, as all electric energy costs are recovered through the ECA. Similarly, all purchased capacity costs are recovered through the PCCA. Therefore, using per-book expense is most representative for calculating a cash working capital amount. The following cash working capital items were calculated in this manner:

coal for steam production; natural gas for other power generation, oil for generation, and electric purchased power.

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 rate schedules with a large number of customers, and used 100 percent sampling for the customers under rate schedules which generally had less than 1,000 customers. 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 REVIEW?

A. The resulting lead-lag factors are presented on Attachment DAB-7. These cash working capital factors were then weighted by the applicable test period costs to calculate Cash Working Capital, as presented on Attachment DAB-1, Schedule 103.

VII. LABOR AND LABOR-RELATED EXPENSES

Q. PLEASE DISCUSS THE ADJUSTMENTS TO INCLUDE WAGE INCREASES IN THE COST OF SERVICE STUDY PRESENTED IN THIS RATE REVIEW.

A. The actual per book labor O&M expense was adjusted for known and measurable cost increases that the Company has paid or is expected to pay through December 31, 2019, a full year after the end of the 2018 HTY, consistent with Commission precedent for making known and measurable adjustments. As discussed by Company witness Mr. Michael T. Knoll, non-bargaining unit employee wage increases are effective March each year. An in-period adjustment is needed to reflect the average increase of 3.00 percent effective March 2018 for the entire period ("2018 adjusted labor"). Added to the 2018 adjusted labor is an out-of-period adjustment to reflect the average increase of 3.00 percent for the wage increase effective March 2019. For bargaining unit employees, as discussed by Company witness Mr. Knoll, wage increases are effective June each year. Similar to the adjustments made for the non-bargaining wage increases, I have made an in-period adjustment to adjust the bargaining unit wage increase of 2.80 percent effective June 2018, plus an out-of-period adjustment for the wage increase of 2.80 percent effective June 2019. 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 DAB-D-6*:*

Table DAB-D-6

	Number of month to Escalate	Annual Rate	Rate/Month	Compound per Year	Compound Rate Total
Non-Bargaining					
2018	2	3.00%	0.50%		0.50%
2019	12	3.00%	3.00%	0.02%	3.02%
Total Non-Bargaining					**3.52%**
Bargaining Unit					
2018	5	2.80%	1.17%		1.17%
2019	12	2.80%	2.80%	0.03%	2.83%
Total Bargaining Unit					**4.00%**

For the non-bargaining unit labor, the average percentage increase is 3.52 percent, and for the bargaining unit labor, the average percentage increase is 4.00 percent, as shown on Attachment DAB-1, Schedule 248. In addition, Taxes Other Than Income Taxes was adjusted for the related payroll taxes from these wage increases. The wage increases are incorporated in the cost of service study presented in this rate review, and shown on Attachment DAB-1, Schedule 248.

Q. DID THE COMPANY CONSIDER PRODUCTIVITY GAINS WHEN MAKING THE WAGE ADJUSTMENTS TO THE MYP AND HTY COST OF SERVICE?

A. Yes. The Company prepared a productivity study consistent with the productivity study filed and approved by the Commission in the 2014 Electric 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.[14] The productivity study is a measure of the average of compound growth rates of output per unit of labor from 2008 through 2018, as shown in Attachment DAB-9.

Q. PLEASE DESCRIBE THE METHODOLOGY USED TO DEVELOP THE LABOR PRODUCTIVITY INFORMATION PROVIDED IN ATTACHMENT DAB-9.

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 electric sales, normalized for weather. The input used was total electric labor costs as reported in the Company's FERC Form No. 1, plus electric 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.

[14] 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 REVIEW.

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 presented in this rate review.

First, I started with the per book incentive pay recorded in FERC Account 920, for the 12 months ended December 31, 2018, 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 2019 non-bargaining unit wage increase, to increase incentive pay by 3.00 percent to reflect incentive pay at target, at the 2019 level of costs, as shown on Attachment DAB-1, Schedule 247. The incentive amounts that have been removed from the cost of service study presented in this rate review 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 THE OFFICERS' INCENTIVE COMPENSATION.

A. The Company has excluded the long-term portion of the officers' incentive compensation from the cost of service study presented in this rate review, 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 2018 HTY. Adjustments were made to the 2018 HTY to eliminate all the officers' incentive compensation in the amount of $(9,525,679), as shown on Attachment DAB-1, Schedule 239. Then an adjustment was made to include the portion on officers' incentive compensation that is attributable to environmental goals as approved by the Commission in prior rate proceedings, as shown on Attachment DAB-1, Schedule 240. In addition, as discussed by Company witness Mr. Knoll, the Company is requesting in this rate review recovery of the time-based component of executives and senior exempt participants' incentive compensation, as shown on Attachment DAB-1, Schedule 241. The result is a net elimination of $4,741,007 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.

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 Attachment DAB-1, Schedule 248.

- Steam Production O&M expense;
- Hydro Production O&M expense;
- Other Production O&M expense;
- Transmission O&M expense;
- Regional Market O&M expense;
- Distribution O&M expense;
- Customer operations expense; and
- Administrative and general (“A&G”) expense.

VIII. COST OF FUEL AND PURCHASED POWER

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

A. All fuel and purchased energy costs were removed from base rates in Phase II from a previous electric rate case in Proceeding No. 04S-164E. These costs are included in the ECA. All purchased demand costs were removed from base rates in the Company's 2006 Rate Case in Proceeding No. 06S-234EG, and are included in the PCCA. Therefore, the fuel and purchased power costs are set to zero in the cost of service study presented in this rate review.

IX. PRODUCTION O&M EXPENSE ADJUSTMENTS

Q. WHAT ADJUSTMENTS WERE MADE TO PRODUCTION O&M EXPENSES?

A. Adjustments were made to: 1) include labor and employee expenses recorded in FERC Account 501, Steam Power Fuel and FERC Account 547, Other Production Fuel; 2) reclassifying fuel handling and transportation costs; 3) eliminate costs recorded in FERC Account 557, Other Power Supply Expenses, that are related to other recovery mechanisms; 4) eliminate expenses associated with the trading department; 5) eliminate expenses associated with incremental sales; 6) include an annual amount of expense associated with Rush Creek Wind Project; and 7) eliminate prior period accounting adjustments.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE LABOR AND EMPLOYEE EXPENSES FROM THE COST OF FUEL ACCOUNTS TO O&M EXPENSES.

A. The Company recorded labor and employee expenses in FERC Accounts 501 and 547, which are cost of fuel expense accounts that would normally be eliminated because these costs are recovered through the ECA. However, labor and employee expense costs are not recovered through the ECA, so these costs needed to be reclassified as Steam Production and Other Production O&M expenses and recovered in base rates. The adjustment is shown on Attachment DAB-1, Schedule 261.

Q. PLEASE DISCUSS RECLASSIFYING FUEL HANDLING AND TRANSPORTATION COSTS FROM COST OF GOODS SOLD TO PRODUCTION O&M EXPENSE.

A. The Company records all fuel costs in FERC Account 501, Fuel, including fuel handling and transportation costs, all of which are considered Cost of Goods Sold in our accounting records. The majority of fuel costs recorded in FERC Account 501 is recovered from customers through the ECA. However, the fuel handling and transportation costs are not recovered through the ECA; these costs are recovered through base rates. Therefore, these costs are included in Production O&M expense, as shown on Attachment DAB-1, Schedule 201.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE COSTS THAT ARE RELATED TO OTHER RECOVERY MECHANISMS.

A. An adjustment was made eliminate costs recorded in FERC Account 557, Other Power Supply Expenses that are related to other recovery mechanisms that should not be recovered through base rates. These costs include deferred fuel costs associated with the ECA and costs associated with the RESA. The adjustment to eliminate these costs is shown on Attachment DAB-1, Schedule 245.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE THE O&M EXPENSES ASSOCIATED WITH THE COMPANY'S TRADING DEPARTMENT.

A. In the Company's 2006 Rate Case in Proceeding No. 06S-234EG, the Commission approved a Settlement Agreement in which gross margins from the Company's short-term energy trading activities would be shared through the ECA. The Company was allowed to recover one-half of a retail jurisdictional share of trading O&M expenses from the Generation and Proprietary Books prior to sharing gross margins with retail customers and recover the remaining half of trading O&M through base rates. The Company is proposing to continue the sharing of gross margins through the ECA using the same methodology approved in the 2006 Rate Case. The level of trading O&M expense that has been used in the ECA calculations up to this point is the amount from the 2014 Electric Rate Case. The Company is proposing to update the trading A&G expenses that will be used in the ECA calculation going forward to the Test Year level reflected in this rate review. To recognize that one-half of these costs are recovered through the ECA, and the remaining half is recovered through base rates, the Company has made an adjustment to eliminate one-half of these expenses from the cost of service. These costs are primarily recorded in FERC Account 557, Other Power Supply Expenses. In addition, these costs are also recorded in several other accounts including: FERC Account 550, Other Production Rents, FERC Account 920, Administrative Salaries, FERC

Account 921, Administrative Office Supplies, FERC Account 925, Injuries and Damages Expense, FERC Account 926, Employee Pension and Benefits Expense, FERC Account 930.1, General Advertising, and FERC Account 408, Taxes Other Than Income Taxes – Payroll Taxes. The adjustment to eliminate one-half of the trading O&M is shown on Attachment DAB-1, Schedule 253. These amounts are also included in the ECA tariff sponsored by Company witness Ms. Applegate.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE THE COSTS ASSOCIATED WITH WHOLESALE INCREMENTAL SALES.

A. An adjustment was made to the cost of service study presented in this rate review to eliminate costs associated with the wholesale incremental sales booked to FERC Accounts 557, Other Power Supply Expenses and 575.7, Transmission Market Administration, Monitoring and Compliance Services. These sales are excluded from the cost of service, and therefore, any costs associated with these sales booked to Production O&M and Regional Market O&M expense should also be excluded. The adjustments are shown on Attachment DAB-1, Schedule 243.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE AN ANNUAL AMOUNT OF O&M COSTS ASSOCIATED WITH THE RUSH CREEK WIND PROJECT.

A. An adjustment was made to the cost of service study to include the 2019 level of O&M costs associated with the Rush Creek Wind Project, as discussed by Company witness Mr. Williams. With Rush Creek going in service on

December 7, 2018, there is less than one month of O&M expense in the Test Year, therefore, costs were added to reflect the level of O&M expense in 2019. The total O&M expenses in this rate review associated with the Rush Creek Wind Project are shown on Attachment DAB-12.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE PRIOR PERIOD EXPENSES FROM THE 2018 HTY.

A. There are two adjustments to the 2018 HTY to remove prior period expenses booked in 2018 that were applicable to other periods. First, as discussed by Company witness Ms. Koch, in November 2018, the Company booked a Colorado Use Tax liability applicable to purchases for the period 2014 through 2018. This was recorded to both capital and expense accounts. The Company is only proposing to remove the amounts charged to expense that are applicable to periods prior to 2018, as shown on Attachment DAB-1, Schedule 257. Therefore, the 2018 HTY has a full year of Colorado Use Tax included in expense. The Company is not proposing any adjustments for the capital amounts, since the capital balances are accumulated. The Colorado Use Tax amounts for 2014 through 2017 are a legitimate cost the Company has incurred, that was not expected. The Company is requesting to amortize the 2014 through 2017 expenses over three years, similar to the other amortizations proposed in this rate review, as discussed later in my Direct Testimony.

Second, in December 2017, the Company accrued an amount for expenses that had not been processed through our accounting system before the end of the year, that were applicable to purchases and services for 2017. The accrual was booked in December 2017 to FERC Account 923, Outside Services. In January 2018, the accrual was reversed and the expenses were processed and charged to the proper FERC expense accounts. An adjustment to the 2018 HTY was made to reverse the accrual reversal in FERC Account 923 and the amounts in various FERC expense accounts applicable to 2017 costs, as shown on Attachment DAB-1, Schedule 236.

The Colorado Use Tax adjustment was recorded to various FERC Accounts and impacts the Production, Transmission, Distribution, Customer Operations and A&G expenses presented in this rate review. The 2017 expense adjustment was also recorded to various FERC Accounts and impacts Production, Transmission, Distribution and A&G expenses presented in this rate review.

X. TRANSMISSION O&M EXPENSE ADJUSTMENTS

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

A. The following adjustments were made to Transmission O&M expense: 1) eliminate wheeling expenses associated with purchased power; 2) include known and measurable adjustments to wheeling expenses; 3) include the costs of the 188 MW Point to Point Reservation from Craig to Four Corners; 4) remove any expenses related to Mountain West Transmission Group; and 5) include the 2019 level of Wildfire Mitigation expenses. In addition, as previously mentioned, an adjustment was made to eliminate prior period expenses from transmission accounts that were recorded in the 2018 HTY, as shown on Attachment DAB-1, Schedules 236 and 257.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE WHEELING EXPENSES ASSOCIATED WITH PURCHASED POWER EXPENSES.

A. An adjustment was made to eliminate the wheeling expenses associated with purchased power expenses recorded in FERC Account 565, Transmission of Electricity by Others (also referred to as Wheeling expense), that are recovered through the ECA, as shown on Attachment DAB-1, Schedule 201.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE OTHER WHEELING EXPENSES RECOVERED IN BASE RATES.

A. As discussed by Company witness Ms. Paoletti, there are other wheeling expenses that are incurred that are not related to purchased power expenses that are recovered through base rates. The Company is proposing to adjust the HTY for known and measurable adjustments for changes in rates or contracts. The adjustments to wheeling expense are shown on Attachment DAB-1, Schedule 251.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE THE 188 MW POINT TO POINT RESERVATION FROM CRAIG TO FOUR CORNERS IN THE COST OF SERVICE STUDY FILED IN THIS RATE REVIEW.

A. As discussed by Company witness Ms. Paoletti, Commercial Operations has had a 188 MW Point-to-Point ("PTP") reservation under the Xcel Energy Operating Companies Joint Open Access Transmission Tariff ("Xcel Joint OATT"), which it has made consistent with the requirements of the Federal Energy Regulatory Commission, from Craig to Four Corners on Public Service's transmission system. We reserved the path in order to complement our generating resources used to meet our planning reserve requirements by providing us access to energy import opportunities. This has allowed Public Service to lower the reserves it carries with its own resources, which lower the Company's production costs. The 188 MW PTP reservation has been included in the studies used to determine the appropriate level of planning reserves in our retail Electric Resource Plan cases. In addition, the 188 MW PTP reservation has been included in our transmission system peak in the development of the jurisdictional allocation factor, which reduces the proportion of the transmission system revenue requirements that is allocated to our retail and firm wholesale customers since the beginning of the reservation. The cost of the reservation is recorded in FERC Account 565, and was approximately $7,523,060 million in 2018. The Company discovered that the cost of the reservation was inadvertently not included in the revenue requirements in prior rate cases. The Company is correcting this mistake and including this cost in the HTY filed in this rate review, as a production demand cost, as shown on Attachment DAB-1, Schedule 251.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE COSTS IN THE 2018 HTY ASSOCIATED WITH MOUNTAIN WEST TRANSMISSION GROUP.

A. On April 20, 2018, Public Service announced that continued engagement in Mountain West Transmission Group was not in the best interests of customers and it was ending its participating in MWTG. Therefore, the Company has made an adjustment to eliminate costs recorded in the 2018 HTY associated with the effort, as discussed by Company witness Paoletti. These expenses were recorded in Transmission, Regional Market, and A&G expense accounts, as shown on Attachment DAB-1, Schedule 234.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE WILDFIRE MITIGATION O&M EXPENSES IN THIS RATE REVIEW.

A. As discussed by Company witnesses Ms. Paoletti and Mr. Nickell, the Company is requesting to include the 2019 level of transmission and distribution O&M expenses associated with the Wildfire Mitigation project in the 2018 HTY. The adjustments are shown on Attachment DAB-1, Schedule 135. As discussed by Company witness Ms. Trammell, the Company is also proposing to defer costs, beginning with the effective date of rates from this case, above the level included in the 2018

HTY. I discuss the level of these costs in the 2018 HTY later in my Direct Testimony.

XI. REGIONAL MARKET O&M EXPENSE ADJUSTMENTS

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

A. The adjustments to Regional Market O&M expenses, as previously discussed in my Direct Testimony is to eliminate expenses associated with incremental sales (Attachment DAB-1, Schedule 243) and Mountain West Transmission Group expenses (Attachment DAB-1, Schedule 234).

XII. DISTRIBUTION O&M EXPENSE ADJUSTMENTS

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

A. Adjustments were made to Distribution O&M expense to include: 1) expenses associated with the AGIS projects; 2) an adjustment for the proposed changes in the Charges for Rendering Services Tariff; 3) an adjustment to eliminate expenses associated with the sale of street lights to the City of Golden; 4) adjustments associated with the City of Boulder municipalization and separation cases; and 5) an adjustment to eliminate any incremental expenses associated with providing Mutual Aid to Puerto Rico. In addition, as previously mentioned, an adjustment was made to eliminate prior period expenses from distribution O&M accounts that were recorded in the 2018 HTY, as shown on Attachment DAB-1, Schedule 236 and 257, and an adjustment was made to include the 2019 level of Wildfire Mitigation expenses, as shown on Attachment DAB-1, Schedule 135.

Q. PLEASE DISCUSS THE ADJUSTMENT TO DISTRIBUTION O&M FOR THE AGIS PROJECTS.

A. As discussed by Company witnesses Mr. Nickell and Mr. Harkness, the Company has estimated the O&M expenses associated with the AGIS projects for calendar year 2019 that have been added to the 2018 HTY. The AGIS O&M expenses are only incremental costs and do not include internal labor. Beginning with the effective date of rates from the case, expected January 1, 2020, any difference in the actual AGIS O&M costs for projects approved in the Settlement Agreement in the AGIS CPCN Projects and the amounts included in base rates in this rate review will be deferred in a Regulatory Asset, and will be recovered in a future base rate case. The adjustments to Distribution O&M expense are shown on Attachment DAB-1 Schedule 137.

Q. PLEASE DISCUSS THE ADJUSTMENT TO REFLECT THE COMPANY'S PROPOSED CHANGES TO THE CHARGES FOR RENDERING SERVICES TARIFF.

A. As discussed by Company witness Ms. Applegate, the Company is proposing to increase the effective rates for the Charges for Rendering Services Tariff related to the non-gratuitous labor performed for service work. The revenues billed on these rates are recorded as a credit in Distribution O&M expense, FERC Account 587, Customer Installations. I have included an adjustment to reflect this additional credit, as shown on Attachment DAB-1, Schedule 260.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE THE EXPENSES ASSOCIATED WITH SALE OF STREET LIGHTS TO THE CITY OF GOLDEN.

A. As previously discussed, the Commission has recently approved the Company's application to sell street lights to the City of Golden in Proceeding No. 18A-0883E. The Company has made adjustments to the 2018 HTY to remove the assets, O&M expenses and revenues associated with these assets. An adjustment was made to FERC Account 596, Maintenance of Street Lights, to eliminate the expenses associated with the sale of street light to the City of Golden, as shown on Attachment DAB-1, Schedule 124.

Q. PLEASE DISCUSS THE ADJUSTMENTS TO 2018 HTY RELATED TO THE CITY OF BOULDER'S PROPOSED MUNICIPALIZATION AND SEPARATION CASES.

A. The Company has made adjustments to the 2018 HTY related to the City of Boulder's proposed municipalization and separation cases before the Commission, as discussed by Company witness Mr. Dietenberger. First, the Company has made adjustments to A&G expenses and payroll taxes to eliminate any costs associated with the municipalization case that are not reimbursable from the City of Boulder. Second, beginning in September 2017, with the Commission's order in Proceeding No. 15-0589E, the Company is currently being reimbursed from the City of Boulder for its costs related to the separation of assets. During 2018, the Company billed the City of Boulder for these costs incurred in 2017 and 2018, and recorded reductions to the Distribution O&M and A&G expenses. I have made adjustments to eliminate both the charges and the credits booked to Distribution O&M, A&G expenses, and payroll taxes for any 2017 and 2018 costs being reimbursed by the City of Boulder, resulting in no net costs in base rates associated with these transactions. All of the adjustments related to the City of Boulder municipalization and separation cases are shown on Attachment DAB-1, Schedule 235.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE ANY INCREMENTAL EXPENSES ASSOCIATED WITH PROVIDING MUTUAL AID TO PUERTO RICO TO REPAIR DAMAGE CAUSED BY HURRICANE MARIA.

A. As discussed by Company witness Mr. Nickell, Xcel Energy received a request for assistance on December 16, 2017, and was one of more than 20 electric companies committed to accelerating ongoing power-restoration efforts after Hurricane Maria hit the island of Puerto Rico in September, 2017. This assistance is referred to as Mutual Aid. Crews from across Xcel Energy operating companies, including Public Service, were sent to Puerto Rico in late January, 2018. The Company was reimbursed for their costs in this restoration effort. The costs were recorded in FERC Account 588, Miscellaneous Distribution Operations expense. The reimbursed revenues were recorded in FERC Account 456, Miscellaneous Revenue. Adjustments were made to eliminate the non-labor costs from Distribution O&M expenses and to eliminate the revenue from Miscellaneous Revenue. Internal labor costs were not eliminated because these costs would have been incurred regardless if the work was being done in Puerto Rico or Colorado. The adjustments to Distribution O&M are shown on Attachment DAB-1, Schedule 250.

XIII. CUSTOMER OPERATIONS EXPENSE ADJUSTMENTS

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

A. Adjustments were made to: 1) include interest expense on customer deposits; 2) adjust the DSM expenses to the level of DSM costs approved by the Commission in the 2009 Rate Case; and 3) eliminate the Renewable*Connect Program Administration Costs. In addition, as previously mentioned, an adjustment was made to eliminate prior period expenses associated with the Colorado Use Taxes from customer operations accounts that were recorded in the 2018 HTY, as shown on Attachment DAB-1, Schedule 257.

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 review is 2.05 percent, which is the current Commission approved rate effective January 1, 2019, as approved in Decision No. C18-0937, Proceeding No.18M-0732E. The adjustment is shown on Attachment DAB-1, Schedule 230.

Q. PLEASE DISCUSS THE ADJUSTMENT TO DSM COSTS.

A. In the 2009 Rate Case, the Company included the 2010 DSM costs in base rates, equal to approximately $89 million. The Company is not proposing to change the level of DSM costs in base rates. The amount of DSM expense in the HTY recorded in FERC Account 908, Customer Assistance Expense is equal to the Company's total DSM expenses, which is greater than the level of DSM costs in base rates, the difference is being collected through the DSMCA. An adjustment is made to reduce the DSM expenses to the level of DSM costs approved in the 2009 Rate Case. The adjustment is shown on Attachment DAB-1, Schedule 222.

Q. PLEASE DISCUSS THE ADJUSTMENT TO ELIMINATE THE RENEWABLE*CONNECT PROGRAM ADMINISTRATION COSTS.

A. As approved by the Commission in Proceeding No. 16A-0055E, the Renewable*Connect Charge in the tariff includes the recovery of program administration costs. Program administration costs include any direct program administration costs (labor), marketing/outreach costs and costs to build and maintain IT systems to support the Renewable*Connect programs. These costs are primarily recorded in Customer Operations expenses and have been eliminated from base rates in this rate review. In addition, there are labor-related costs in recorded in Administrative and General expense and Payroll Taxes that have also been eliminated. The adjustments are shown on Attachment DAB-1, Schedule 258.

Q. HAVE YOU INCLUDED SAFETY, CONSERVATION, AND CUSTOMER PROGRAM RELATED ADVERTISING COSTS IN THE COST OF SERVICE?

A. Yes, these types of advertising expenses are included in the cost of service study presented in this rate review. The Company is providing copies of the ads for the 12-month period ending December 31, 2018, along with their related costs in Attachment DAB-10.

XIV. ADMINISTRATIVE & GENERAL EXPENSE ADJUSTMENTS

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) Eliminate expenses associated with trading activities;
4) Adjust FERC Account 922, for additional shared asset costs for AGIS;
5) Adjust property insurance expenses for the Rush Creek Wind project;
6) Adjust the level of pension and benefits expenses in the HTY to the 2019 level of costs;
7) Eliminate the pension expense amount that was deferred in the 2018 HTY above the pension expense baseline;
8) Adjust active healthcare expense for claims incurred-but-not-reported;
9) Adjust retiree medical expenses to zero out the negative expenses;
10) Adjust the regulatory Commission expense for the Commission's current level of assessment fees;
11) Include the incremental costs for preparing and litigating this rate review and other cases that have been deferred; and,
12) Eliminate certain advertising expenses;

In addition, as previously mentioned, adjustments were made to eliminate prior period expenses, as shown on Attachment DAB-1, Schedules 236 and 257; an adjustment was made to eliminate Mountain West Transmission Group expenses from A&G accounts that were recorded in the 2018 HTY, as shown on Attachment DAB-1, Schedule 234; an adjustment was made to eliminate amounts recorded in A&G expenses associated with the municipalization and separation efforts of the City of Boulder, as shown on Attachment DAB-1, Schedule 235; and, an adjustment was made to eliminate Renewable*Connect program administration costs recorded in A&G expenses, as shown on Attachment DAB-1, Schedule 258.

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

A. The Company is proposing to recover 11.194 percent of the costs associated with the corporate aircraft in base rates. An adjustment was made to eliminate 88.806 percent of the corporate aircraft costs included in the HTY cost of service study totaling ($1,302,614) and shown on Attachment DAB-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 in the 2018 HTY. 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 were made to Taxes Other Than Income Taxes for the related payroll taxes.

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

A. The employee expense adjustment resulted from a review of the actual accounting transactions for the 12 months ending December 31, 2018. The review identified approximately ($188,827) in certain costs recorded in operating accounts and assigned to the Electric Department that did not meet travel policy guidelines as recoverable from customers. We searched electronically the employee expense transactions that were allocated or assigned to the Company and incorrectly recorded to operating accounts based on using key words and categories. This analysis is similar to what we have filed in prior rate cases. The adjustment is shown on Attachment DAB-1, Schedule 227.

Q. PLEASE DISCUSS THE ADJUSTMENT THE COMPANY MADE TO ELIMINATE EXPENSES ASSOCIATED WITH THE TRADING ACTIVITIES.

A. As previously discussed, the Company made adjustments to eliminate expenses associated with trading activities. Adjustments were made to FERC Account 920, Administrative Salaries, FERC Account 921, Administrative Office Supplies, FERC Account 925, Injuries and Damages, FERC Account 926, Employee Pension and Benefits, and FERC Account 930.1, General Advertising, as shown on Attachment DAB-1, Schedule 253.

Q. PLEASE DISCUSS THE ADJUSTMENT THE COMPANY MADE FOR ADDITIONAL SHARED SERVICE CREDITS ASSOCIATED WITH AGIS.

A. As discussed by Company witness Mr. Nickell, the AMI software head-end asset currently being used by Public Service is also going to be used by other Operating Companies of Xcel Energy with the deployment of AMI meters. This asset will be considered a shared asset for purposes of accounting. Company witness Ms. Wold discusses the shared asset calculation. The Company has made an adjustment to FERC Account 922, Administrative Expenses Transferred – Credit for the amounts that will be credited to the Company and charged to the other Operating Companies for the use of this asset. The adjustment is presented on Attachment DAB-1, Schedule 137.

Q. PLEASE DISCUSS THE ADJUSTMENT TO PROPERTY INSURANCE FOR RUSH CREEK?

A. In 2018, the Company recorded property insurance associated with Rush Creek as construction costs in CWIP. As previously discussed, Rush Creek was placed into service in December 2018. The Company will be incurring property insurance expense in 2019. Therefore, an adjustment was made to FERC Account 924, Property Insurance, to reflect a full year of property insurance associated with Rush Creek, as shown on Attachment DAB-1, Schedule 231.

Q. PLEASE DISCUSS THE LEVEL OF PENSION AND BENEFITS EXPENSE INCLUDED IN THE 2018 HTY.

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 2019 level are included in the 2018 HTY presented in this rate review. The pension and benefits adjustments are shown on Attachment DAB-1, Schedule 233. As discussed by Ms.Trammell, the Company is proposing to continue to use a pension expense tracker, in which the retail pension costs in the 2018 HTY will set the level of pension expenses for the deferral beginning January 1, 2020. The amount of the 2018 HTY retail pension expenses are $16,199,266, are shown below in Table DAB-D-7.

Table DAB-D-7

	Total Electric	Retail Allocator	CPUC Amount
Qualified Pension	$16,569,574	94.04%	$15,581,650
Non-Qualified Pension	$ 656,793	94.04%	$ 617,634
Total	$17,226,367		$16,199,266

Pension expenses incurred beginning with the effective date of rates in this rate review, expected January 1, 2020 that are greater or lower than the 2018 HTY 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 PENSION AND BENEFITS EXPENSE TO ELIMINATE THE AMOUNT THAT WAS DEFERRED IN THE 2018 HTY ABOVE THE PENSION EXPENSE BASELINE ESTABLISHED IN THE 2014 ELECTRIC RATE CASE.

A. An adjustment was made to eliminate the pension expense amount that was deferred in the 2018 HTY above the pension expense baseline established in the 2014 Electric Rate Case, in order to reflect the current level of pension expense in this rate review, as discussed by Company witness Mr. Schrubbe. In addition, the Company is proposing to amortize the deferred pension expenses in this rate review as discussed later in my Direct Testimony. The adjustment to eliminate the pension expense that was deferred in the 2018 HTY is shown on Attachment DAB-1, Schedule 233.

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

A. As discussed by Company witness Mr. Schrubbe, the actual amount booked in the 2018 HTY for active healthcare expense is an estimate at year end. Claims that are incurred in the HTY but not reported until after the books close should be adjusted in the HTY. This adjustment in the amount of $345,314 is a decrease to FERC Account 926, Employee Pensions and Benefits expense as shown on Attachment DAB-1, Schedule 228.

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

A. As discussed by Company witness Mr. Schrubbe, the Company recorded negative retiree medical expenses in 2018. The Company is proposing an adjustment similar to what was approved in the recent 2017 Gas Rate Case, to zero out the negative expense, in other words increase expense, and lower the prepaid balance in rate base, as shown on Attachment DAB-1, Schedule 255.

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

A. The Company made an adjustment to FERC Account 928, Regulatory Commission Expense in the 2018 HTY to reflect the Commission administration fees for the fiscal year July 1, 2018 through June 30, 2019, as shown on Attachment DAB-1, Schedule 229. The 2018 books and records has this level of Commission administration fees through December 31, 2018. The adjustment is to bring in the expenses through June 30, 2019 in the 2018 HTY.

Q. PLEASE DESCRIBE THE ADJUSTMENT TO A&G EXPENSE FOR COSTS INCURRED FOR RATE CASE EXPENSES OR OTHER REGULATORY PROCEEDINGS BEFORE THE COMMISSION IN WHICH THE COMPANY HAS DEFERRED THE COSTS FOR FUTURE RECOVERY.

A. As discussed by Company witness Ms. Trammell, this adjustment includes the actual costs incurred to date, plus the estimated incremental costs of preparing, filing and litigating this rate review. Such incremental costs include the cost of customer noticing, duplicating, postage, consultant and outside witness fees, transcripts, and outside legal fees. In addition, the Company has also included the incremental costs associated with other regulatory proceedings before the Commission into the total rate case expenses presented in this rate review, including: the 2016 Depreciation Case; the 2016 Phase II Rate Case expenses; the 2016 Phase II Electric Rate Case pilot expenses; and the dismissed 2017 Electric Rate Case (Proceeding No. 17AL-0649E), which includes costs for settlement proposals related to the TCJA Revised Settlement in the TCJA Statewide Proceeding (Proceeding No. 18M-074EG), and costs related to bifurcated TCJA Proceeding (Proceeding No. 18M-0401E) for an Administrative Law Judge to determine if the Revised Settlement was in the public interest, net of any expenses supporting the TCJA quarterly reporting in the miscellaneous 2018 TCJA proceeding. The Company is proposing to amortize the total of these costs over three years, effective with the base rates in this rate review. The Company has requested that rates become effective in this rate review on January 1, 2020, resulting in a 36-month amortization period. In general, the amortization period should reflect the amount of time the Company expects between rate cases, which is the average period between electric rate cases since the 2011 Rate Case. The rate case expense adjustment to A&G expense is shown on Attachment DAB-1, Schedule 123.

Q. HAS THE COMPANY INCLUDED ANY EXPENSE IN THE COST OF SERVICE STUDY PRESENTED IN THIS RATE REVIEW ASSOCIATED WITH RATE CASE EXPENSES FROM THE 2014 ELECTRIC RATE CASE?

A. No. The rate case expenses from the 2014 Electric Rate Case were amortized over a 36-month period, which ended December 31, 2017.

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, Miscellaneous A&G expense, in the amount of ($3,260,934) have been eliminated, as shown on Attachment DAB-1, Schedule 237.

XV. DEPRECIATION EXPENSE ADJUSTMENTS

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO DEPRECIATION EXPENSE.

A. Several adjustments to depreciation expense have been made in the HTY cost of service study presented in this rate review. Adjustments were made to:

1) Reclassify Intangible Plant-related depreciation expenses to functional depreciation expense accounts (Attachment DAB-1, Schedule 139);

2) Adjust depreciation expenses related to the plant adjustments as previously discussed, e.g., Holy Cross Distribution Substations, Pawnee Control Panel, Golden Street Lights, AGIS, Wildfire Mitigation, 2019 Plant Additions, and Rush Creek (Attachment DAB-1, Schedules 125, 129, 124, 137, 156, 135, 140, and Attachment DAB-12);

3) Include the results of new depreciation rates approved in the 2016 Depreciation Case, including the amortization of the early plant retirements;

4) Annualize the year-end depreciation expense at the year-end 2018 level; and,

5) Include the 2019 level of depreciation expense associated with the 2019 capital additions.

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

A. Company witness Ms. Wold sponsors the new depreciation study and associated depreciation rates, approved in the 2016 Depreciation Case. Consistent with her testimony, I have incorporated the annual impact of the changes in depreciation rates to depreciation expense in the HTY presented in this rate review, shown on Attachment DAB-1, Schedule 232. Please note the Company implemented the Common plant depreciation rates effective January 1, 2018, following a final decision in the 2017 Gas Rate Case, Proceeding No. 17AL-0363G. In addition, the

Company is proposing a new service life for the AGIS AMI meters that is reflected in the depreciation expense presented in this rate review, as discussed by Company witness Ms. Wold. The Company will implement the change in the Electric utility Production, Transmission, Distribution, General, and Intangible depreciation rates with the effective date of rates from this rate review, to match when revenue begins to be collected for these expenses.

Q. PLEASE DISCUSS THE AMORTIZATION OF THE EARLY PLANT RETIREMENTS.

A. As discussed by Company witness Ms. Wold, the Company is proposing to amortize the balances of the Retired Generating Units regulatory assets, as well as the Craig Unit 1 regulatory asset over a seven year amortization period, consistent with the 2016 Depreciation Case Settlement Agreement, approved by the Commission in Decision No. R16-1143, in the 2016 Depreciation Case. The amortization of the Retired Generating Units regulatory assets, and the new depreciation rates have been assumed to begin on January 1, 2020, the requested effective date of rates in this rate review. For the 2018 HTY, a full year of the amortization has been reflected. However, the actual amortization and changes in depreciation rates will begin to be recorded on the books with the effective date of rates from this rate review. The adjustment for the early plant retirement amortization is shown on Attachment DAB-1, Schedule 232.

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 2018 HTY to reflect the December 31, 2018 level of depreciation expense based on the December 2018 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 DAB-1, Schedule 226.

Q. PLEASE DISCUSS THE ADJUSTMENT TO INCLUDE DEPRECIATION EXPENSES ASSOCIATED WITH THE 2019 CAPITAL ADDITIONS ADJUSTMENT.

A. As previously discussed, the Company is making an adjustment in this rate review to include the 2019 plant additions expected to be in-service before December 31, 2019, at the 2019 year-end level. Therefore, an adjustment was made to include the annualized 2019 depreciation expense associated with these capital additions, including the AGIS and Wildfire Mitigation (Distribution portion) projects. The adjustment is presented on Attachment DAB-1, Schedule 140

XVI. AMORTIZATION EXPENSE ADJUSTMENTS

Q. PLEASE DESCRIBE THE ADJUSTMENTS TO AMORTIZATION EXPENSE.

A. Several adjustments to amortization expense have been made in the HTY cost of service study presented in this rate review. Adjustments were made to:

1) Eliminate the amortization of the property tax regulatory asset balance;
2) Eliminate property tax amount that was deferred in the 2018 HTY above the property tax expense baseline;
3) Eliminate the amortization of net legacy prepaid pension regulatory asset;
4) Include the amortization of the property tax regulatory asset balance;
5) Include the amortization of the pension expense regulatory liability;
6) Include an amortization associated with the ICT regulatory assets;
7) Include an amortization associated with the AGIS CPCN projects;
8) Include an amortization associated with the sale of certain assets; and
9) Include an amortization of the Colorado Use Tax liability.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO THE 2018 HTY AMORTIZATION EXPENSE ASSOCIATED WITH THE 2014 ELECTRIC RATE CASE.

A. There are three adjustments to amortization expense that were associated with the 2014 Electric Rate Case that were eliminated from the 2018 HTY. First, an adjustment was made to eliminate the amortization of the property tax regulatory asset balance that accumulated during 2012 through 2014 as approved in the 2014 Electric Rate Case. This property tax regulatory asset amortization ended December 31, 2017; however, the Company has continued to expense this amount in 2018 and credit the property tax deferred balance. The Company has made an adjustment to eliminate this expense from the 2018 HTY. Second, an adjustment was made to eliminate the property tax expense that was deferred in the 2018 HTY above the property tax baseline that was established in the 2014 Electric Rate Case, in order to reflect the current level of property taxes expense in this rate review. Finally, the Company has made an adjustment to the 2018 HTY to eliminate the amortization of the Legacy Prepaid Pension Asset established in the 2014 Electric Rate Case. As previously discussed, in the Commission-approved TCJA Settlement, the Company agreed to apply a portion of the TCJA savings to the Legacy Prepaid Pension Asset. As a result, as discussed by Company witness Mr. Schrubbe, the Legacy Prepaid Pension Asset balance is $0 (zero) in mid-2019. However, the Company is expecting to continue this amortization through the end of 2019, or until rates are effective from this rate review, and reduce the Prepaid Pension Asset in rate base. These adjustments to eliminate amortization expense from the 2018 HTY are shown on Attachment DAB-1, Schedule 201.

Q. ARE THERE ANY AMORTIZATIONS FROM THE 2014 ELECTRIC RATE CASE THAT ARE NOT BEING ADDRESSED IN THIS RATE REVIEW?

A. Yes. There are two amortizations from the 2014 Electric Rate Case that have expired and are not being addressed in this rate review. First, as I previously mentioned, the rate case expense amortization from the 2014 Electric Rate Case expired at the end of December 2017. Therefore, there is no adjustment to remove any amortization expense from FERC Account 928, Regulatory Commission expense. Second, in the 2014 Electric Rate Case, the Company included an amortization of Mountain Pine Beetle (MPB) costs which were incurred from

January 1, 2013 through December 31, 2014 above or below the $6 million in base rates. The MPB amortization ended December 31, 2017, and therefore no adjustment was required in the 2018 HTY.

Q. DOES THE COMPANY PROPOSE IN THIS RATE REVIEW ANY AMORTIZATION OF THE REGULATORY ASSETS AND LIABILITIES APPROVED IN THE 2014 ELECTRIC RATE CASE?

A. Yes. In the 2018 HTY, the Company is proposing to amortize two of the regulatory assets approved in the 2014 Electric Rate Case. These amortizations include the deferred property taxes and the deferred pension expenses and discussed in detail below.

Q. PLEASE DISCUSS THE DEFERRED PROPERTY TAX AMORTIZATION.

A. As approved by the Commission in the 2014 Electric 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 2014 Electric Rate Case and the actual incurred retail property taxes beginning with calendar year 2015. 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 2014 Electric Rate Case was $109,506,702. The Company is proposing in the 2018 HTY to amortize the actual deferred retail property tax deferred balance through December 31, 2018, plus the estimated 2019 deferral. Any difference in the actual 2020 property taxes from the level of retail property taxes in this rate review (2018 HTY baseline), plus the deferrals through the effective date of rates in this rate review, will be recovered in the next rate case. In the 2018 HTY, the forecasted deferral through December 31, 2019 is being amortized over five years. This amortization period is consistent with the Settlement Agreement in the 2014 Electric Rate Case that required the amortization to be over the same number of years that the balance accumulated. The amortization of the property tax deferred balance is shown on Attachment DAB-1, Schedule 238.

Q. PLEASE DISCUSS THE PENSION EXPENSE AMORTIZATION.

A. As approved by the Commission in the 2014 Electric Rate Case, the Company has deferred pension expenses since the last rate case. The Company has recorded regulatory liability account for the difference in retail pension expense included in base rates from the 2014 Electric 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 2014 Electric 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 2014 Electric Rate Case was as follows:

Non-Qualified Pension Expense	$883,950
Qualified Pension Expense	$21,086,171

The Company is proposing in the 2018 HTY to amortize the actual deferred retail pension expense balance through December 31, 2018. Any difference in the actual 2020 pension expense deferral from the level of retail pension expenses in this rate review (2018 HTY baseline), plus the deferrals through the effective date of rates in this rate review, will be recovered in the next rate case. In the 2018 HTY, the forecasted deferral through December 31, 2018 is being amortized over three years, consistent with the amortization period proposed in this rate review for other regulatory assets/liabilities, as discussed below. The amortization for the pension expense deferred balance is shown on Attachment DAB-1, Schedule 238.

Q. PLEASE DISCUSS THE ICT PROJECTS AMORTIZATION.

A. As discussed by Company witness Mr. Ihle, the Commission approved the installation of two new ICT projects, the Panasonic Project and the Stapleton Project, and the deferral of capital expenditures and O&M expenses in a regulatory asset account in Decision No. C16-0196, Proceeding No. 15A-0847. The Company has included in the 2018 HTY, the amortization of the regulatory asset balance associated with the capital expenditures of the ICT projects at December 31, 2018 of $8,769,166, over a 10 year period, the estimated life of these assets. The Company has also included in the 2018 HTY, the amortization of the regulatory asset balance associated with the O&M expenses of the ICT projects at December 31, 2018 of $13,806, over a three year period, consistent with the amortization period proposed in this rate review for other regulatory assets/liabilities. Any ICT project capital expenditures or O&M expenses incurred through December 31, 2019 will continue to be deferred and included in a future rate case. The amortization for the ICT projects deferred balances are shown on Attachment DAB 1, Schedule 238.

Q. DOES THE COMPANY EXPECT ADDITIONAL CAPITAL EXPENDITURES OR O&M EXPENSES ASSOCIATED WITH THE ICT PROJECTS AFTER 2019?

A. As discussed by Company witness Mr. Ihle, the Company does not expect to incur any additional capital expenditures after 2019, but does expect on-going O&M expenses. However, the exact level of O&M expenses is not known at this time. As supported by Mr. Ihle, the Company is proposing in this rate review to continue deferring the on-going O&M expenses associated with the ICT projects, and will seek to recover these costs in a future rate case.

Q. PLEASE DISCUSS THE AMORTIZATION OF THE DEFERRED AGIS COSTS.

A. As approved by the Commission in the AGIS CPCN case, Proceeding No. 16A-0588E, the Company has been deferring costs in 2018 associated with the AMI, IVVO and the associated FAN projects. The Company has set up two deferred accounting mechanisms for each project, one for O&M expenses and the second for the capital investment. The capital investment costs the Company is deferring is the depreciation expense. The capital investment through December 31, 2018 was not greater than $50 million, therefore no interest has been accrued. The Company has included in the 2018 HTY, the amortization of the regulatory asset balance associated with the AGIS CPCN projects of $1,841,073, over a three-year period, consistent with the other amortization periods requested in this rate review. The amortization for the AGIS CPCN projects deferred balances are shown on Attachment DAB-1, Schedule 238.

Q. DOES THE COMPANY EXPECT TO CONTINUE THE DEFERRAL OF AGIS CPCN PROJECT COSTS AFTER THE IMPLEMENTATION OF RATES IN THIS RATE REVIEW?

A. Yes. As discussed by Company witness Ms. Trammell, and consistent with the Commission approved Settlement Agreement in the AGIS CPCN case, the Company will continue deferred accounting for O&M as well as capital investments beginning with the effective date of rates from this rate review. The Settlement Agreement stated that "Settling Parties agree to continued deferred accounting for O&M expenses as well as capital investments beyond the first rate case in which those costs could be included in base rates."[15] Beginning with the effective date of rates in this rate review, the Company will defer AGIS CPCN costs above the level of costs in the 2018 HTY. I summarize the level of AGIS CPCN costs in the 2018 HTY below in Table DAB-D-9.

Q. PLEASE DISCUSS THE AMORTIZATION OF THE GAIN ON SALE OF CERTAIN ASSETS.

A. As discussed by Company witness Ms. Trammell, the Company is proposing to amortize the gain on the sale of certain assets in this rate review. The adjustment in the 2018 HTY related to the gain on sale of utility property relates to the Green/Clear Lakes property, which was sold on January 6, 2016 and is discussed by Company witness Ms. Trammell. Ms. Trammell further explains for depreciable assets that have been included in the Company's regulated rate

[15] Proceeding No. 16AL-0588E, Settlement Agreement, Sections I.B.1, II.D.3.b, and III.E.2.

base, Public Service proposes that the net gains and losses be allocated between customers and the Company based on the percentage of the depreciable asset that has been depreciated, with the depreciated percentage portion of the gain or loss allocated to customers and the remainder to the Company. I would note the Green/Clear Lakes property is recorded on the books and records as Common General property. The amount of the gain on the sale of the depreciable property included in 2018 HTY has been allocated to the electric department based on the Common Plant allocator. The Company, consistent with other amortizations proposed in this rate review, is proposing to amortize this gain on the sale of utility property over three years, and the unamortized balance has been included in rate base. The gain on the sale of assets is being amortized over a 36-month period, consistent with the other amortization periods proposed in this rate review. The amortization for the gain on the sale of certain assets is shown on Attachment DAB-1, Schedule 238.

Q. PLEASE DISCUSS THE AMORTIZATION OF THE COLORADO USE TAX LIABILITY.

A. As previously discussed, the Company is proposing to amortize the Colorado Use Tax liability applicable to purchases for the period 2014 through 2017 that was paid in 2018. The Company is requesting to amortize the 2014 through 2017 expenses over three years, similar to the other amortizations proposed in this rate review. The adjustment is presented on Attachment DAB-1, Schedule 238.

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

A. Please see Table DAB-D-8 below, which shows the non-plant amortizations included in the 2018 HTY.

Table DAB-D-8

Description	Deferred Balance	Time Period	Start Date	2018 HTY
Property Tax	$ 12,949,355	60 Months	1/1/2020	$ 2,589,871
Pension	$ 3,320,547	36 Months	1/1/2020	$ 1,106,849
ICT Capital	$ 8,769,166	120 Months	1/1/2020	$ 876,917
ICT O&M	$ 13,806	36 Months	1/1/2020	$ 4,602
AGIS CPCN Costs	$ 1,841,073	36 Months	1/1/2020	$ 613,691
Gain on the Sale of Assets	$ (115,548)	36 Months	1/1/2020	$ (38,516)
Colorado Use Tax	$ 968,269	36 Months	1/1/2020	$ 322,756
Rate Case Expenses	$ 7,669,077	36 Months	1/1/2020	$ 2,556,359
Total				**$ 8,032,529**

As previously discussed in my Direct Testimony, in the 2018 HTY, the Company is proposing an amortization period of 36 months for most of regulatory assets/liabilities except for Property Tax and the ICT capital projects. The Company is proposing an amortization of six years for the Property Tax deferral, consistent with the period of time the deferral was accrued, and an amortization of 10 years for the ICT projects, the expected life of these assets.

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

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

1 **Table DAB-D-9**

	2018 HTY
Property Tax Expense	$ 145,551,258
Qualified Pension Expense	$ 15,581,650
Non-Qualified Pension Expense	$ 617,634
AGIS CPCN O&M	$ 7,708,445
AGIS CPCN Capital Investment	$ 6,182,174
Wildfire Mitigation O&M	$ 10,860,710
Wildfire Mitigation Capital Investment	$ 742,109

2 The amounts presented in this table are the retail level of expenses in the 2018
3 HTY in this rate review.

XVI. TAXES OTHER THAN INCOME TAX EXPENSE ADJUSTMENTS

Q. ARE THERE ANY NEW TAXES OTHER THAN INCOME TAXES PRESENTED IN THIS RATE REVIEW FROM THAT PRESENTED IN PRIOR RATE CASES?

A. Yes. As discussed by Company witness Ms. Koch, the Company has been earning enterprise zone investment tax credits ("EZITCs") for several years, subject to taxable income limitations. The Company had recognized EZITCs as a tax credit in the income tax calculation. However, as a result of Rush Creek being placed in-service in 2018, the Company will now recognize a Colorado Renewable Energy Investment Tax Credit or renewable "ITC" that is being limited to $750 thousand each year. The renewable ITC is a refundable credit that we cannot account for in the income tax calculation. Instead, in 2018, the renewable ITC was recorded as a credit to FERC Account 408, Taxes Other Than Income, and included in the 2018 HTY on Attachment DAB-1, Schedule 201.

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 (Attachment DAB-1, Schedules 247 and 248;
2) Officers' incentive compensation (Attachment DAB-1, Schedules 239, 240, and 241);
3) Aviation labor (Attachment DAB-1, Schedule 224);
4) Trading labor (Attachment DAB-1, Schedule 253);

5) Labor related to the City of Boulder municipalization and separation efforts (Attachment DAB-1, Schedule 235); and
6) Renewable*Connect labor (Attachment DAB-1, Schedule 258).

Q. PLEASE DISCUSS THE PRESENTATION OF PROPERTY TAX EXPENSE IN THE 2018 HTY PRESENTED IN THIS RATE REVIEW.

A. Company witness 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 electric 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. Trammell, the Company is proposing to continue the property tax expense tracker. If property tax expenses incurred in 2020 are greater or less than the level included in this rate review, 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 ADJUSTMENTS TO PROPERTY TAX EXPENSE IN THE 2018 HTY.

A. The Company has made several adjustments for property taxes in this rate review. First, as previously discussed, an adjustment was made to amortization expense in the 2018 HTY to bring the property tax to the 2018 level, as a tracker was in place as a result of the 2014 Electric Rate Case, which set the base amount at the 2013 level. Second, an adjustment was made to eliminate the property tax credit from the City of Pueblo associated with the Comanche generating station. This property tax credit, when paid by the City of Pueblo, is credited to retail customers through their ECA recovery mechanism, and is not included in base rates. Third, an adjustment was made to update the utility allocation of property taxes. The utility allocation of property taxes in the 2018 books and records was based on the 2017 level of plant balances. An adjustment was made to reflect the utility allocator at the 2018 level of plant balances. The result is an adjustment to lower the electric property taxes in the 2018 HTY. Fourth, an adjustment was made to eliminate prior period amounts booked in 2018. Fifth, as discussed by Company witness Ms. Koch, an adjustment was made to increase property taxes for changes in property tax rates as a result of the November 2018 elections. Finally, an adjustment was made to bring the property taxes to the 2019 level, which includes the Rush Creek Wind Project. These assets were not reflected in the 2018 level of property taxes.

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XVII. INCOME TAX EXPENSE ADJUSTMENTS

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

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 review, the Schedule M items, permanent tax differences, and deferred income tax expense related to plant are detailed on Attachment DAB-1, Schedule 200. The Schedule M items, permanent tax differences, and deferred income tax expense related to non-plant are detailed on Attachment DAB-1, 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. 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 review 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 Attachment DAB-1, Schedule 115.

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

A. Generally, yes. However, the Company has made three changes to the calculation of income taxes in this rate review from prior rate cases. First, as discussed by Company witness Ms. Koch, the state income tax rate used in this rate review is a composite rate for Colorado and California state income taxes. Second, as previously discussed, the Section 199 Domestic Production Deduction ("Section 199") established by the American Jobs Creation Act of 2004 ("the Act") was repealed with the TCJA. Therefore, the Section 199 credit is not included in the income tax calculation in this rate review. Finally, as discussed later in my Direct Testimony, the Enterprise Zone Investment Tax Credits that were previously a tax credit in the income tax calculation are now recorded as a credit in FERC Account 408, Taxes Other than Income Taxes.

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 previously discussed, e.g., Holy Cross Distribution Substations, Pawnee Control Panel, Golden Street Lights, AGIS, Wildfire Mitigation, 2019 Plant Additions, and Rush Creek (Attachment DAB-1, Schedules 125, 129, 124, 137, 156, 135, 140, and Attachment DAB-12);

2) The elimination of accounts that are not included in the cost of service study (Attachment DAB-1, Schedule 115); and,

3) Deferred tax expense includes an annual amount of amortization of the excess ADIT as a result of implementing the TCJA (Attachment DAB-1, Schedule 127).

Q. IS THE COMPANY IN A NET OPERATING LOSS TAX POSITION IN THE 2018 HTY?

A. No. As previously discussed, the Company is not in a NOL tax position in the 2018 HTY. The Company has enough taxable income in 2018 to use all of the income tax addition/deductions. In addition, the Company does not have an NOL carryforward from prior years. 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 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 Attachment DAB-1, Schedule 104.

XVIII. GAIN ON SALE OF SO_2 ALLOWANCES AND UTILITY PLANT

Q. PLEASE DESCRIBE WHAT IS INCLUDED IN THE COST OF SERVICE STUDY PRESENTED IN THIS RATE REVIEW FOR THE GAIN ON THE DISPOSITION OF SO_2 ALLOWANCES.

A. Any gains on the disposition of emission credits due to the Department of Energy auction are included in 2018 HTY, as shown on Attachment DAB-1, Schedule 201.

Q. ARE THERE ANY GAINS ON THE SALE OF UTILITY PLANT INCLUDED IN THIS RATE REVIEW?

A. Yes, as previously discussed, the Company is proposing to amortize the gain on sales of utility property, and has included an amortization of the gain in amortization expense.

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

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

A. No. As previously discussed, the Company has eliminated all of CWIP from rate base in this rate review. Historically, the Commission has a long-standing ratemaking policy that if CWIP is included in rate base, than an AFUDC offset to earnings is required.

XX. OTHER REVENUE ADJUSTMENTS

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

A. The following other revenues accounts are included in the cost of service study presented in this rate review, including: FERC Account 449, Provision for Rate Refund; FERC Account 450, Late Payment Revenue; FERC Account 451, Miscellaneous Service Revenue; FERC Account 454, Rent Revenue; FERC Account 456.0, Other Electric Revenue; and FERC Account 456.1, Revenues from Transmission of Electricity of Others. The Company used the 2018 balances of the other revenue accounts in the 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:

- addition of a negative amount to FERC Account 456.0, Other Electric Revenue, for the partial rate recovery of the Southeast Water Rights booked in Plant Held for Future Use (Attachment DAB-1, Schedule 223);
- elimination of residential late payment revenues; and,
- elimination of other revenue amounts not included in retail base rates; *i.e.*, Joint Operating Agreement revenue, firm point-to-point and network transmission service billed under the Xcel Joint OATT associated with the FERC jurisdictional customers, other FERC jurisdictional revenues, Interruptible Service Option Credit revenues, customer discounts, DSM incentives, Quality of Service Plan credits, deferred fuel, out-of-period adjustments, TCA, CACJA, and Rush Creek true-up estimates, earnings

sharing adjustment estimates, and lost revenues under the medical exemption program.

The adjustments to other revenue are shown on Attachment DAB-1, Schedule 211.

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

A. Yes. The Company made two new adjustments to Other Revenue in this rate review from what has been presented in prior rate cases. First, as discussed by Company witness Ms. Applegate, 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 451, 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 Attachment DAB-1, Schedule 212. Second, as previously discussed, the Company is making an adjustment to eliminate any incremental expenses associated with the Mutual Aid work in Puerto Rico. The Company is also eliminating the revenue associated with this work from FERC Account 456, Other Electric Revenue, as shown on Attachment DAB-1, Schedule 211.

Q. ARE THERE ANY NEW OTHER REVENUES IN THIS RATE REVIEW YOU WOULD LIKE TO DISCUSS?

A. Yes. As discussed later in my Direct Testimony, FERC Account 456, Other Electric Revenue includes revenues associated with the management fees from the Joint Dispatch Agreement. These revenues are associated with our production costs and are allocated to the retail jurisdiction based on the production allocator.

Q. ARE THERE ANY OTHER REVENUE ADJUSTMENTS THAT WERE MADE IN PREVIOUS CASES THAT ARE NOT BEING MADE IN THIS RATE REVIEW?

A. Yes, as discussed by Company witness Ms. Trammell, we are not including any revenues in this rate review associated with the oil and gas royalties.

Q. PLEASE DESCRIBE THE COMPANY'S TREATMENT OF RESIDENTIAL LATE PAYMENT REVENUE IN THIS RATE REVIEW.

A. The Company has eliminated the residential late payment revenue billed to customers in 2018 HTY, as shown on Attachment DAB-1, Schedule 211. The Company proposes to eliminate this revenue credit and continue the donation to Energy Outreach Colorado ("EOC"), consistent with the treatment of residential late payment revenue the Commission approved in the Company's last electric rate case.

XXI. JURISDICTIONAL ALLOCATION

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

A. The retail jurisdictional allocations used in this rate review 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 REVIEW?

A. The jurisdictional allocation factors are presented on Attachment DAB-1, Schedule 300. The derivation of the labor allocation factors are presented on Attachments DAB-1, Schedule 300. The production, transmission, and distribution demand fundamental allocation factors were calculated based on a 12 Coincident-Peak method, consistent with previous Commission precedent.

Q. HAVE THERE BEEN ANY SIGNIFICANT CHANGES TO THE WHOLESALE CONTRACTS THAT ARE REFLECTED IN THE JURISDICTIONAL ALLOCATION FACTORS?

A. Yes. A known and measurable adjustment was made to the Production demand and Transmission demand allocation factors to reflect a notice from one of the Company's Wholesale Customers, Town of Center, that they are leaving the system April 2020. Additionally, the Transmission demand allocation factor was also adjusted to reflect the expiration of a point-to-point transmission reservation by Western Area Power Administration that ended in February 2018.

Q. DID THE COMPANY IDENTIFY ANY DIRECT ASSIGNMENTS OF RATE BASE ITEMS OR EARNINGS ITEMS TO EITHER THE RETAIL OR THE WHOLESALE JURISDICTIONS IN THIS RATE REVIEW?

A. Yes. The direct assignments, by jurisdiction, are identified as separate lines in the 2018 HTY and are presented primary on Attachment DAB-1, Schedule 220, and other schedules as noted below. The Company has made direct assignments to the wholesale jurisdiction for: a) distribution substations and meters in gross plant; b) customer billing and customer assistance expenses; and c) wholesale regulatory expenses. In addition, the Company has made direct assignments to the retail jurisdiction, including the following:

- The Electric Department's portion of the investment in the software system used for billing retail customers only, the Customer Resource System ("CRS") (Attachment DAB-1, Schedule 113);
- The investment in the SmartGridCity™ project (Attachment DAB-1, Schedule 131);

- The investment in the AGIS projects which will only be borne by the retail customers (Attachment DAB-1, Schedule 137);
- A portion of distribution substations are directly assigned to retail;
- Transmission fees paid to Western Electricity Coordinating Council ("WECC") and Peak Reliability recorded in FERC Account 561.8, Industry associated dues paid to the Edison Electric Institute and Electric Power Research Institute recorded in FERC Account 930.2, and retail regulatory expenses recorded in FERC Account 928 are all only borne by retail customers; and,
- Rent expense that supports the retail jurisdictional customers.

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

A. No. However, there are a couple of items of note that have occurred since the 2014 Electric Rate Case. First, as I previously mentioned, the Company has implemented RIS, a new model for if revenue requirements calculations. With that implementation, the Company has data by FERC Account for balance sheet and income statement accounts. For the plant-related accounts, e.g., accumulated reserve for depreciation, ADIT, depreciation expense, the data is by FERC Plant Account, and it is at this level, the costs are allocated by jurisdiction in this rate review. In the 2014 Electric Rate Case, these accounts were allocated to the retail jurisdiction based on derived allocators by plant function. For instance, the Distribution Accumulated Reserve for Depreciation balance was allocated to the retail jurisdiction based on the distribution plant in service balance. The allocation of these accounts to the retail jurisdiction in this rate review are by FERC plant account, and is more consistent with the allocation of gross plant in-service, than in prior rate reviews. Second, the Rush Creek Wind Project has been approved by the Commission, including the retail jurisdictional allocation of this project. The production assets of this project are recorded in the Other Production accounts in the FERC System of Accounts, and the transmission serving generation assets of this project are recorded in Transmission accounts in the FERC System of Accounts, which both are traditionally allocated to the retail jurisdiction based on production demand. As approved by the Commission in Decision No. C16-0958, in Proceeding No. 16A-0117E, the production and transmission serving generation assets of the Rush Creek Wind Project will be allocated to the retail jurisdiction based on the energy allocator. The transmission and the electric general assets of the Rush Creek Wind Project follow the existing retail jurisdictional allocation method for these assets. These retail allocation methodologies are consistent with the current recovery of the Rush Creek Wind Project in the ECA.

XXII. CAPITAL STRUCTURE

Q. WHAT IS THE BASIS FOR THE CAPITAL STRUCTURE USED IN THE 2018 HTY?

A. The long-term debt and equity balances included in the HTY capital structure are based on the March 31, 2019 balances to reflect the most current capital structure to provide a better match to the rate base balances included in the 2018 HTY. The HTY capital structure is shown on Attachment DAB-1, Schedule 3, as sponsored by Company witness Ms. Sarah W. Soong. As discussed by Ms. Soong, if the Company's adjustment to include 2019 plant additions in rate base is not approved, then the actual December 31, 2018 capital structure should be used to set base rates in this rate review.

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

A. Yes. These adjustments to the book balances are reflected in Attachment DAB-1, Schedule 3.

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.

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

A. As discussed by Company witness Ms. Soong, the Company calculated the cost of debt by dividing the interest costs plus all related issuance costs by the gross debt balance, which is known as the "par value" method, which is consistent with what has been approved by this Commission in previous rate cases.

XXIII. BASE REVENUE

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

A. The present base rate revenue used in the 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 four adjustments to the test period billing units. First, as discussed in the Direct Testimony of Ms. Jannell E. Marks, the Company has normalized the energy sales and demand based on the weather normalization. Second, the Company made 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 base rates. Third, as previously discussed, the Company has made an adjustment to remove the street lights sold to the City of Golden. In addition, as discussed by Company witness Ms. Applegate, the Company is proposing to increase the rates it charges under its Maintenance Charges for Street Lighting Service Tariff. The revenues billed for street light maintenance service are recorded in FERC Account 444, Public Street and Highway Lighting Revenue. The new proposed rates will increase the base revenues reflected in the cost of service. The adjustment to reflect the new proposed rates for street light maintenance service is shown on Attachment DAB-1, Schedule 212. The derivation of present base rate revenue is shown on Attachment DAB-1, Schedule 210. Retail present base rate revenue for the HTY is $1,610,815,905, exclusive of the present GRSA of negative 4.19 percent. Including the present GRSA of negative 4.19 percent, the total retail present base rate revenue is $1,543,322,719.

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

A. The Company is presenting the 2018 HTY using year-end rate base and annualized depreciation expense. The annualization adjustment to the HTY base revenue reflects the projected revenue of new residential, commercial & industrial, lighting and public authority customers that have been added to the Company's electric system that were not on the system during all of calendar year 2018, but who are expected to be served after the 2018 HTY. This adjustment results in the addition of $10,218,893 of revenue to the 2018 HTY and thus reduces the deficiency by the same amount, as shown on Attachment DAB-1, Schedule 210.

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 HTY to the end of the HTY. Results of this calculation shows that residential customer counts have grown by 9,401 customers, commercial & industrial customer counts have grown by 192 and lighting customer counts have decreased by 15.

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 HTY. This approach resulted in total adjusted base rate revenue of $10,218,893 of which $4,826,289 was for residential customers, $5,385,876 for commercial & industrial customers and $6,728 for lighting customers.

XXIV. REVENUE REQUIREMENTS AND EARNINGS DEFICIENCY

Q. WHAT IS THE OVERALL RETAIL REVENUE REQUIREMENTS FOR THE 2018 HTY?

A. The overall retail revenue requirements for the 2018 HTY is $1,951,002,985.

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

A. The revenue deficiency is calculated by comparing the overall retail revenue requirements to the present base revenues. The resulting 2018 HTY revenue deficiency is $407,737,776, as shown on Attachment DAB-1, Schedule 2.

Q. HAS THE COMPANY CALCULATED A GENERAL RATE SCHEDULE ADJUSTMENT RIDER THAT WOULD BE APPLICABLE TO ALL ELECTRIC BASE RATES BASED ON THE REVENUE DEFICIENCY PRESENTED IN THIS RATE REVIEW?

A. Yes. The proposed GRSA will be calculated to recover the $407,737,776 of additional revenues based on 2018 HTY sales. This increase represents a 25.29 percent increase from what is currently collected from customers under base rates plus the existing negative 4.19 percent GRSA. The increase reflects: 1) a 21.10 percent increase from existing base rate revenues; and 2) the increase attributable to ending the existing negative 4.19 percent GRSA currently in effect. Based on 2018 HTY base rate revenues, the Company is proposing a 21.10 percent increase to existing base rate revenue through a 13.00 percent GRSA and a base rate kWh charge designed to collect $130,677,238 of energy specific charges associated with the Rush Creek Wind Project. The base rate kWh charge will be known as "GRSA-E" rider. The GRSA and the GRSA-E riders are shown on Attachment DAB-1, Schedule 2 and Schedule 2.1.

XXV. FUNCTIONALIZED COST OF SERVICE

Q. WHAT IS MEANT BY A FUNCTIONALIZED COST OF SERVICE?

A. The functionalized cost of service starts with the retail jurisdictional cost of service, as presented in Attachment DAB-1, then classifies plant investment and expenses by system component, such as production, transmission, distribution, or customer operations. For the most part, the classification of costs is accomplished through the Company's accounting system. These costs are then functionalized, which takes the classification a step beyond the accounting records, and further separates these costs by the primary cost driver for that cost into three basic functions: 1) variable costs related to the quantity of electric energy produced and sold, 2) fixed costs associated with the provision of adequate system capacity to produce and deliver that energy, and 3) customer costs related the existence of a customer connected to, and receiving service from, the electric system. The functional cost of service study is a revenue requirements calculation for each identified function.

Q. HAS THE COMPANY PREPARED A FUNCTIONALIZED COST OF SERVICE STUDY IN THIS RATE REVIEW?

A. Yes. The Company has prepared a Functionalized Cost of Service Study that is presented in Attachment DAB-2.

Q. PLEASE DESCRIBE THE FUNCTIONAL COST OF SERVICE STUDY.

A. The layout of the Functional Cost of Service Study is parallel to the Jurisdictional Cost of Service Study. However, the starting point for the Functional Cost of Service Study is not total Company cost, but rather the allocated Colorado PUC jurisdictional portion of each rate base and expense item. In other words, the output of the Jurisdictional Cost of Service Study is the input for the Functional Cost Allocation Study. These total Colorado PUC jurisdictional costs are then allocated to 19 specific cost functions.

Q. HOW DID YOU DETERMINE THE 19 SPECIFIC COST FUNCTIONS?

A. There were two considerations in establishing these specific cost functions. The first was to separately recognize the classification of plant investment and expenses by system component; that is: production, transmission, distribution, and customer operations and to separately recognize variable, fixed and customer related costs within each classification. The second consideration was to ensure that all of the individual cost components that will be required to properly allocate costs among retail rate classes, and design the various retail rates, were identified in separate functions. These 19 functions are represented by the column headings on Attachment DAB-2.

Q. ARE THESE COST FUNCTIONS CONSISTENT WITH THE PRIOR RATE CASE?

A. Yes. These same cost functions were filed in the 2014 Rate Case, and also were the basis for the current rates approved in the last Phase II Electric Rate Case, Proceeding No. 16AL-0048E.

Q. WHAT WAS THE BASIS FOR THE ALLOCATION OF THESE COSTS TO THE VARIOUS FUNCTIONS?

A. The retail jurisdictional costs are allocated to the 19 functions based on direct or derived allocation factors. The fundamental allocators are basically direct assignments of the plant or expense items that define each specific function. For example, Steam Production Plant in Service is directly assigned to the "Production Capacity Cost – Steam Production" function, and Meter reading Expense is directly assigned to the "Customer Cost – Meter Reading" function. The derived allocators were calculated using the same assumptions and principals that are used for jurisdictional allocation purposes. The functional allocation factors are shown on Attachment DAB-1, Schedule 301.

Q. IS THE COMPANY PROPOSING TO CHANGE THE FUNCTIONAL ALLOCATION OF COSTS IN THIS RATE REVIEW FROM WHAT WAS APPROVED IN THE 2014 RATE CASE?

A. Yes. As agreed to in the 2016 Phase II Rate Case, in the Settlement Agreement approved by the Commission in Decision No. C16-1075, the Company has assigned distribution load dispatching costs, recorded in FERC Account 581, to those functions that these costs support, rather than to only distribution substations. These costs are being allocated to the following distribution functions in this rate review, based on the plant in-service balances:

- Distribution Substations
- Distribution Primary System
- Distribution Secondary System

Distribution load dispatching costs have not been allocated to the Service Laterals, Metering or Lighting Distribution functions, as these costs are not related to these functions.

Q. ARE THERE ANY NEW COSTS IN THIS RATE REVIEW THAT WERE NOT INCLUDED IN THE 2014 RATE CASE THAT REQUIRES A FUNCTIONAL ALLOCATION FACTOR BE ASSIGNED?

A. Yes. The AGIS projects are new costs that require functional allocation factors be assigned. Below are the jurisdictional and functional allocation factors that are assigned to the AGIS projects in this rate review:

Table DAB-D-10

FERC Account	AGIS Project	Jurisdictional Allocation Factor	Functional Allocation Factor
Capital			
303	ADMS	CPUC	Split by Primary/Secondary
303	AMI	CPUC	Distribution Meters (DISTMET)
361	ADMS & IVVO	CPUC	Split by Primary/Secondary
361	AMI	CPUC	Distribution Meters (DISTMET)
361	FAN & FLISR	CPUC	Distribution Primary (DISTPRI)
362	FAN	CPUC	Distribution Primary (DISTPRI)
362	IVVO	CPUC	Split by Primary/Secondary
390	AGIS Other	CPUC	Split by Primary/Secondary
391	ADMS & IVVO	CPUC	Split by Primary/Secondary
391	AMI	CPUC	Distribution Meters (DISTMET)
391	FAN	CPUC	Distribution Primary (DISTPRI)
394	AMI	CPUC	Distribution Meters (DISTMET)
394	AGIS Other	CPUC	Split by Primary/Secondary
397	ADMS & IVVO	CPUC	Split by Primary/Secondary
397	FAN & FLISR	CPUC	Distribution Primary (DISTPRI)

O&M Expenses			
588	AMI	CPUC	Distribution Meters (DISTMET)
588	FAN & FLISR	CPUC	Distribution Primary (DISTPRI)
588	ADMS, IVVO & Other	CPUC	Split by Primary/Secondary
593	FLISR	CPUC	Distribution Primary (DISTPRI)
593	IVVO	CPUC	Split by Primary/Secondary
597	AMI	CPUC	Distribution Meters (DISTMET)
598	ADMS	CPUC	Split by Primary/Secondary
598	FAN	CPUC	Distribution Primary (DISTPRI)
909	FLISR	CPUC	Distribution Primary (DISTPRI)

Q. WHAT ARE THE RESULTS OF THE FUNCTIONAL COST OF SERVICE STUDY?

A. The Functional Cost of Service Study breaks down the Company's total retail jurisdictional revenue requirements by specific cost function. The total of the 19 individual functional revenue requirements is shown on Attachment DAB-2 equal to the total retail jurisdictional revenue requirements requested in this rate review.

XXVI. IMPACT OF ROLLING CURRENT RIDERS INTO BASE RATES

A. CACJA Rider

Q. HAVE YOU CALCULATED THE REVENUE REQUIREMENTS ASSOCIATED WITH THE CACJA THAT IS INCLUDED IN THE COST OF SERVICE STUDY PRESENTED IN THIS RATE REVIEW?

A. Yes. The revenue requirement associated with the CACJA included in the 2018 HTY is shown on Attachment DAB-11. As discussed by Ms. Applegate, the Company is proposing to roll into base rates the costs currently recovered through the CACJA Rider.

Q. PLEASE DESCRIBE HOW THE CACJA RIDER WILL BE CALCULATED BEGINNING WITH THE EFFECTIVE DATE OF THE BASE RATE CHANGE IN THIS RATE REVIEW.

A. The CACJA Rider will be set to zero effective with the base rate change in this rate review, except for any true-ups from prior years, to ensure there is no double recovery of these costs. The Company will file to update the current CACJA Rider, effective January 1, 2020 in November 2019. Although the Company is requesting that base rates from this rate review become effective January 1, 2020, the Company still plans to calculate the 2020 CACJA Rider using the 13-month average estimated net plant in-service balances at December 31, 2020, and all other plant-related costs and the estimated 2020 O&M expenses, plus the 2018 true-ups. Once base rates resulting from this rate review are effective in 2020, on January 1, 2020 or shortly thereafter, the 2020 CAJCA Rider will be set to zero except for any true-ups from prior years that are included in the 2020 CACJA Rider. In April 2020, the Company will file its final CACJA Annual Report to provide information on the true-up of 2019 estimated rates.

Then effective January 1, 2021, the CACJA Rider will only include the true-up for calendar 2019, and the CACJA Rider tariff will then be cancelled effective January 1, 2022.

B. Rush Creek

Q. HAVE YOU CALCULATED THE REVENUE REQUIREMENT ASSOCIATED WITH RUSH CREEK THAT ARE INCLUDED IN THE COST OF SERVICE STUDY PRESENTED IN THIS RATE REVIEW?

A. Yes. The revenue requirements associated with the Rush Creek Wind Project included in the 2018 HTY is shown on Attachment DAB-12. As discussed by Ms. Applegate, the Company is proposing to roll into base rates the Rush Creek Wind Project costs currently recovered through the ECA, with the exception of the PTCs and Capital Cost sharing, which will continue to be recovered through the ECA.

Q. WHAT WILL BE INCLUDED IN THE ECA BEGINNING WITH THE EFFECTIVE DATE OF THE BASE RATE CHANGE IN THIS RATE REVIEW ASSOCIATED WITH THE RUSH CREEK WIND PROJECT?

A. The ECA will not include any costs associated with the Rush Creek Wind Project beginning with the base rate change in this rate review, except for any true-ups from prior years, to ensure there is no double recovery of these costs. The PTCs and Capital Cost sharing will continue to be recovered through the ECA. Additionally, the Company will file to update the ECA, effective January 1, 2020 in December 2019. Although the Company is requesting that base rates from this rate review become effective January 1, 2020, the Company still plans to include in the 2020 ECA the costs of the Rush Creek Wind asset using the 13-month average estimated net plant in-service balances at December 31, 2020, and all other plant-related costs and the estimated 2020 O&M expenses. Once base rates resulting from this rate review are effective in 2020, on January 1, 2020 or shortly thereafter, the 2020 ECA will need to be lowered to remove Rush Creek from the calculation.

C. <u>TCA RIDER</u>

Q. HAVE YOU CALCULATED THE REVENUE REQUIREMENT ASSOCIATED WITH THE TCA RIDER INCLUDED IN THE 2018 HTY PRESENTED IN THIS RATE REVIEW?

A. Yes. The revenue requirement associated with the TCA rider included in the 2018 HTY is shown on Attachment DAB-13, page 1. The 2018 HTY TCA revenue requirement will set the base level of TCA costs that will be used to calculate the TCA rider beginning with the effective date of rates from this rate review.

Q. PLEASE GIVE AN EXAMPLE OF HOW THE TCA CALCULATIONS WILL BE PERFORMED BEGINNING WITH THE EFFECTIVE DATES OF RATES FROM THIS RATE REVIEW.

A. The Company will file to update the current TCA, effective with the date of rates from this rate review. The Company is requesting that base rates from this rate review become effective January 1, 2020, and the Company will file to update the TCA, also effective January 1, 2020 ("2020 TCA"), in November 2019. The 2020 TCA will be calculated using the incremental 13-month average estimated transmission net plant in-service balances at December 31, 2020 and the estimated year-end transmission CWIP balance at December 31, 2019, since the Company's 2014 Electric Rate Case. A portion of the amounts included in the 2020 TCA are also included in the 2018 HTY cost of service in this rate review. Once base rates resulting from this rate review are effective in 2020, on January 1, 2020 or shortly thereafter, the 2020 TCA will be reduced to remove any amounts included in the 2018 HTY, to ensure there is no double recovery of these costs. A portion of the 2020 TCA that was designed to recover the net plant component is included in the net plant balance in this rate review, so therefore that component of the 2020 TCA would be set to zero. Since the Company has zeroed the CWIP balance in rate base in this rate review, there will be no TCA CWIP component in base rates with the effective date of rates from this case. In summary, the 2020 TCA, and future TCA rider filings would be adjusted to account for the TCA costs in base costs in the 2018 HTY, until the next base rate review. In addition, the 2020 TCA and all subsequent TCA filings would include any true-up from prior TCA years. I have also calculated the amount of TCA costs we are rolling into base rates from the level of TCA costs in the 2014 Electric Rate Case, as shown on Attachment DAB-13, page 2.

XXVII. BASE COSTS ASSOCIATED WITH THE AGIS PROJECTS

Q. HAVE YOU CALCULATED THE CAPITAL INVESTMENT AND THE O&M ASSOCIATED WITH THE AGIS PROJECTS THAT ARE INCLUDED IN THE 2018 HTY PRESENTED IN THIS RATE REVIEW?

A. Yes. The revenue requirements associated with the AGIS projects that are included in the 2018 HTY are the year-end 2019 level of rate base and O&M expenses, as shown on Attachment DAB-1, Schedule 143. These amounts will set the base level of AGIS projects costs that are in the base rates in this rate review, and will be the basis for the deferral of costs associated with the AGIS CPCN Projects beginning with the effective date of rates from this rate review.

XXVIII. JDA COMPLIANCE

Q. WHAT INFORMATION ARE YOU PROVIDING WITH RESPECT TO THE SPECIFIC COSTS AND REVENUES ASSOCIATED WITH THE JDA?

A. I am providing specific information on the costs and revenues that the Company is seeking prudence of, as required by the Commission in Proceeding No. 16A-0276E. The JDA Software Assets were placed in service January 1, 2017. The original in-service costs were determined to be $664,272 at the close of the project. Based on a three-year amortization schedule (Book and Tax for software assets), I estimate that the 2018 revenue requirements is approximately $253,000. The annual JDA administration fee revenues recorded in 2018 was $345,000. Including the JDA Software Assets and the administration fee revenues results in an annual net benefit of approximately $92,000.

XXIX. CONCLUSION

Q. PLEASE DESCRIBE THE RECOMMENDATIONS YOU ARE MAKING AS PART OF THIS RATE REVIEW.

A. As set forth above, my overarching recommendation is that the Commission approves the retail electric revenue requirement for the 2018 HTY of $1,951,002,985, and the resulting GRSA factors. I also recommend that the Commission approve the TCA and AGIS level of costs in base rates, as well as the inclusion of CACJA Rider and Rush Creek Wind Project revenue requirements in base rates. Finally, I recommend the Commission approve the net JDA revenues.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Deborah A. Blair

I graduated from Colorado State University in 1981 with a Bachelor of Science degree in Business Administration, with an emphasis in accounting. I began my career with Public Service in June 1981 in the Accounting Division. I held several positions in the Accounting Division including the Cheyenne Light, Fuel and Power Company ("Cheyenne") accountant and the Public Service accountant. Cheyenne was formerly a wholly-owned subsidiary of Public Service, but became an operating utility subsidiary of New Century Energies, Inc. upon the completion of the merger between Public Service and Southwestern Public Service Company in 1997, and then became an operating utility subsidiary of Xcel Energy Inc. Cheyenne has since been sold and is no longer a subsidiary of Xcel Energy Inc. In 1982, I accepted a position as a Rate Accountant in the Revenue Requirements Department of Public Service. In 1989, I was promoted to Supervisor, Revenue Reporting and in 1994 was promoted to Unit Manager, Revenue Requirements, both of Public Service. In May 1997, I was promoted to the position of Director, Regulatory Support Services for New Century Services, Inc. In August 2000, I accepted my current position of Director, Revenue Analysis of Xcel Energy Services Inc.

I have testified before the Commission in Proceeding Nos. 93I-199EG, 95S-041E, 95A-531EG, 96S-290G, 97A-299EG, 97S-366G, 98A-262EG, 98A-511E, 98S-518G, 99A-037E, 99A-377EG, 99A-557E, 00A-351E, 06S-234EG, 07A-469E, 08A-497EG, 08S-520E, 09AL-299E, 10AL-963G, 11AL-947E, 12A-782E, 12AL-1264ST, 12AL-1268G, 12AL-1269ST,14AL-0660E, 15AL-0135G, 15A-0589E, 15AL-0877E, 16A-0117E, 16AL-0869E, and 17AL-0649E. I have testified before the Wyoming Public Service Commission in Proceeding No. 30005-GR-97-51 and have submitted written testimony in Proceeding Nos. 20003-EA-95-40, 30005-GA-95-39, 20003-EA-99-53 and 30005-GA-99-69. I have submitted written testimony before the New Mexico Public Regulation Commission in Case Nos. 2798, 3116, 3849, and 15-00343-UT, and before the Public Utility Commission of Texas in Proceeding Nos. 21190, 27052, 42042, 43695, and 45291.

I have testified before the FERC in Proceeding No. EL05-19-002, and have submitted written testimony in Proceeding Nos. ER96-713-000, ER00-536-000, ER03-971-000, ER04-1174-000, ER06-274-000, ER07-1415-000, ER08-313-000, ER08-527-000 ER08-749-000, ER10-192-000, ER10-992-000, ER11-2853-000, ER12-1589-000, ER14-1969-000, ER15-949-000, ER16-180-000, and ER19-1613-000.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * *

RE: IN THE MATTER OF ADVICE NO. 1797-ELECTRIC OF PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO P.U.C. NO. 8-ELECTRIC TARIFF TO IMPLEMENT RATE CHANGES EFFECTIVE ON THIRTY-DAYS' NOTICE.	**) PROCEEDING NO. 19AL-______E**

AFFIDAVIT OF DEBORAH A. BLAIR
ON BEHALF OF
PUBLIC SERVICE COMPANY OF COLORADO

I, Deborah A. Blair, 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 16th day of May, 2019.

Deborah A. Blair
Deborah A. Blair
Director, Revenue Analysis

Subscribed and sworn to before me this 16 day of May, 2019.

Dawn Moffit
Notary Public

DAWN MOFFIT
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20084013859
MY COMMISSION EXPIRES APRIL 22, 2020

My Commission expires 4·22·2020