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**

<u>DIRECT TESTIMONY AND ATTACHMENTS OF MICHELLE M. APPLEGATE</u>

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
2020 CACJA Rider	Clean Air Clean Jobs Act Rider filing in November 2019, effective January 1, 2020
2020 TCA Rider	Transmission Cost Adjustment Rider filing in November 2019, effective January 1, 2020
AFN	Alternative Form of Notice
AMI	Advanced Metering Infrastructure
CACJA or CACJA Rider	Clean Air Clean Jobs Act Rider
CWIP	Construction Work in Progress
EAF	Equivalent Availability Factor
EAFPM	Equivalent Availability Factor Performance Mechanism
ECA	Electric Commodity Adjustment
ESA	Earnings Share Adjustment
GADS	Generating Availability Data System
GRSA	General Rate Schedule Adjustment
HTY	Historical Test Year
M&V	Measurement and Verification
OMC	Outside of Management Control
O&M	Operations and Maintenance
PTC	Federal Production Tax Credits
Public Service or Company	Public Service Company of Colorado
QSP	Quality of Service Plan
Schedule PLL	Parking Lot Lighting Service
Schedule TTOU	Transmission Time-of-Use Service

Acronym/Defined Term	**Meaning**
TCA	Transmission Cost Adjustment
TCJA	Tax Cuts and Jobs Act

**BEFORE THE PUBLIC UTILITIES COMMISSION
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I. INTRODUCTION, QUALIFICATIONS, PURPOSE OF TESTIMONY, AND RECOMMENDATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michelle M. Applegate. My business address is 1800 Larimer Street, Suite 1400, Denver, Colorado 80202.

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

A. I am employed by Public Service Company of Colorado ("Public Service" or the "Company") as Director, Regulatory Administration.

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

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As Director, Regulatory Administration, I provide leadership, direction and technical expertise related to regulatory processes and functions for Public Service. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my Direct Testimony in my Statement of Qualifications.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I cover five primary topic areas in my Direct Testimony. First, I explain how we are proposing to transfer recovery of certain costs from existing riders into base rates. These costs include the revenue requirements associated with our Clean Air-Clean Jobs Act Rider ("CACJA" or "CACJA Rider") and Transmission Cost Adjustment Rider ("TCA"), along with the revenue requirement associated with our Rush Creek Wind Project that is currently being recovered through the Electric Commodity Adjustment ("ECA"). I explain why we are transferring these revenue requirements into base rates, and the rate impact of doing so.[1] Second, I introduce and explain a number of other proposed tariff changes, including revisions to existing tariffs, and provide policy support for these tariff changes. Third, I support the level of rate case expenses requested in this proceeding as well as the three-year amortization of these costs that has been included in the cost of service study presented by Ms. Blair. Fourth, I explain the rationale for our proposal to discontinue the Equivalent Availability Factor Performance Mechanism ("EAFPM") included in the ECA. Finally, I present the Company's proposed classification of Advanced Metering Infrastructure ("AMI") Meter Costs.

[1] Company witness Ms. Deborah A. Blair calculates and presents the specific amount of transmission costs included in the 2018 Historical Test Year ("HTY") that will be used to set the base amount used to calculate the TCA in future years. Similarly, Ms. Blair calculates and presents the specific CACJA Rider and Rush Creek Wind Project revenue requirements that will be recovered through base rates rather than riders as of the effective date in this proceeding.

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

A. Yes, I am sponsoring the following four attachments, which were prepared by me or under my direct supervision:

- Attachment MMA-1: Clean Electric Tariff;
- Attachment MMA-2: Redlined Electric Tariff;
- Attachment MMA-3: Table Summarizing Tariff Changes;
- Attachment MMA-4: Rate Case Expense Detail; and,
- Attachment MMA-5: Classification of AMI Meter Costs.

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

A. I recommend the Commission:

- Approve for inclusion in base rates the 2018 historical test year ("HTY") revenue requirements associated with the CACJA Rider, the TCA, and the Rush Creek Wind Project, for the amounts set forth in my Direct Testimony and as supported by Ms. Blair. As I explain below, these changes do not increase the Company's overall revenues, but rather transfer cost recovery from rider recovery to base rate recovery.

- Authorize the proposed changes to our Electric tariff, as described in Advice No. 1797 – Electric, and included as clean and redlined versions of the Electric tariff in Attachments MMA-1 and MMA-2 to my Direct Testimony.

- Authorize recovery of $7,669,077 in total rate case expenses, including $1,470,241 in rate case expense specifically related to this proceeding, amortized over 36 months. These expenses stem from a number of proceedings including this rate review, as I explain in greater detail in my Direct Testimony.

- Approve the requested discontinuance of the Equivalent Availability Factor Performance Mechanism ("EAFPM") as further described in my Direct Testimony.

- Postpone any decision on the Company's proposal of classification of AMI Meter Costs, which is presented consistent with the directives from Proceeding No. 16A-0588E but is more appropriately addressed in a Phase II rate design proceeding.

II. CACJA, TCA, AND RUSH CREEK WIND PROJECT COST RECOVERY

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

A. In this section of my Direct Testimony, I provide background on rate riders, why they are utilized, and how they operate. I also explain why we are proposing to transfer the recovery of costs currently recovered through certain rider mechanisms, including costs associated with the Rush Creek Wind Project, into Public Service's base rates.

Q. WHAT IS A RIDER?

A. A rate rider or simply a "rider," is a non-base rate cost recovery and billing mechanism that allows a utility to recover specific costs outside of a comprehensive base rate proceeding. Generally, riders are used to recover ongoing but variable costs, like fuel (for example, our ECA), or to recover specific fixed costs (for example, transmission costs through our TCA). Often, costs recovered through riders are significant, and can therefore delay the need to file for a full, comprehensive review of Public Service's base rates.

Q. WHY IS IT APPROPRIATE FOR UTILITIES TO RECOVER CERTAIN COSTS THROUGH RIDERS?

A. In the face of heightened capital spending for a specific project, like the Rush Creek Wind Project, or a capital spending priority, like transmission infrastructure, cost recovery through rate riders is necessary to support the overall financial health of the Company. Riders provide the Company with a reasonable opportunity to earn its authorized return on important capital investments at the same time customers receive the benefits of those investments. The type of test year used to set rates stands to influence the efficacy of a rider.

Q. WHAT ARE SOME EXAMPLES OF COMMISSION-APPROVED RIDERS?

A. The Commission has approved a number of Public Service riders, including, for example, the TCA, CACJA Rider, and ECA. The TCA is authorized by Colorado law and allows for recovery of Public Service's incremental transmission investment.[2] Public Service's CACJA rider allows the Company to recover both its capital and Operations & Maintenance ("O&M") costs associated with eligible projects.[3] Also, while Public Service does not have a discrete rate rider to recover costs associated with our Rush Creek Wind Project, we have been recovering those costs through the ECA.[4] I discuss these riders in more detail below.

Q. PLEASE DESCRIBE THE COMPANY'S REQUEST TO TRANSFER CERTAIN COSTS TO BASE RATES FROM RIDER RECOVERY.

A. It is common practice to move cost recovery from a rider into base rates when capital investment and the associated revenue requirements have stabilized and the Company initiates a base rate review filing. Depending on the rider, the Company may transfer the full rider into base rates when the projects have been

[2] Section 40-5-101(1), C.R.S. The TCA was first approved by Commission Decision No. C07-1085 (mailed Dec. 24, 2007) in Proceeding No. 07A-339E.
[3] Decision No. C15-0292, approving Settlement, Proceeding No. 14AL-0660E.
[4] Decision No. C16-0958, approving Rush Creek Settlement Agreement, Proceeding No. 16A-0117E.

completed, like CACJA, or roll the balance of the rider into base rates and continue recovering incremental costs through the rider going forward, as we do with the TCA. Transferring all or a portion of a rider into base rates does not create a new stream of revenue; rather, it simply shifts revenue that is already being recovered into base rates. In other words, a transfer of certain costs from a rider to base rates should not be considered a driver of the revenue deficiency determined by the cost of service study. So while the Company's total change in base rate revenue as a result of this proceeding is $407,737,776, the resulting incremental base rate revenue increase after transferring approximately $250 million in CACJA, TCA, and Rush Creek Project revenue requirements into base rates is $158,314,011. As described by Company witness Ms. Trammell, this results in a 10.3 percent increase in base rate revenue.

Q. WHY IS THE COMPANY PROPOSING TO TRANSFER INTO BASE RATES COSTS IT IS CURRENTLY RECOVERING THROUGH THESE THREE RATE RIDERS?

A. There are several reasons. First, it is common practice to transfer recovery of certain costs from rate riders into base rates during a rate review proceeding, and it is often (but not always) required by the Commission or statute.[5] For instance, both the CACJA statute, § 40-53.2-207, C.R.S., and the Commission-

[5] For instance, the Company received approval to roll Purchased Capacity Cost Adjustment ("PCCA") and TCA costs from those respective riders into base rates in accordance with Commission Decision No. C12-0494 (mailed May 9, 2012) in Proceeding No. 11AL-947E. The Company also received approval to roll costs recovered through the Pipeline System Integrity Adjustment rider ("PSIA") into base rates in accordance with Recommended Decision No. R15-1204 (mailed Nov. 16, 2015) and Commission Decision No. C16-0123 (mailed Feb. 16, 2016) in Proceeding No. 15AL-0135G.

approved Rush Creek Settlement Agreement[6] contemplate eventual recovery through base rates. In the case of the TCA, the Commission-approved rider specifically provides, "[w]henever the Company implements changes in base rates as the result of a final order in an electric Phase I rate case, it shall simultaneously adjust the TCA to remove all costs that have been included in base rates."[7]

Second, for project-based riders, transferring recovery from the rider into base rates can align with project completion or milestones. This is true for the Rush Creek Wind Project and CACJA projects, which have been placed into service.

Third, when capital investment and the associated revenue requirements stabilize for particular investments, transferring recovery may provide greater rate certainty and stability for customers by shifting cost recovery to base rates on a going-forward basis.

As I mentioned above, transferring cost recovery from riders to base rates does not increase the total revenue collected from retail customers, it merely shifts cost recovery into base rates for the remaining life of the assets.

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[6] Commission Decision No. C16-0958 approving Settlement, Proceeding No. 16A-0117E. The Rush Creek Settlement Agreement provided that the initial cost recovery for Rush Creek would occur through some combination of the ECA and RESA until the Company filed a base rate case following the commercial operation date of the facilities. As with the CACJA project costs and associated revenue requirement, the Company's proposed inclusion of the Rush Creek Wind Project in base rates is consistent with the Settlement Agreement.

[7] COLO. PUC No. 8 Electric, Sheet No. 142C.

Q. PLEASE SUMMARIZE THE AMOUNTS THAT THE COMPANY IS PROPOSING TO TRANSFER FROM RIDER RECOVERY TO BASE RATE RECOVERY IN THIS RATE REVIEW.

A. We are proposing to transfer the 2018 HTY revenue requirements that are currently recovered through the CACJA Rider and TCA into base rates. We are also proposing to move the revenue requirement associated with the Rush Creek Wind Project from the ECA into base rates. Table MMA-D-1 below shows the amount of each revenue requirement we propose to transfer to base rates.

TABLE MMA-D-1:
Public Service – Retail Electric
CACJA, TCA and Rush Creek Revenue Requirements Transferring to Base Rates

Rate Rider	Revenue Requirement
Clean Air-Clean Jobs Act Rider	$ 78,719,151
Transmission Cost Adjustment	$ 40,027,376
Rush Creek Wind Project (ECA)	$ 130,677,238
Total Revenue Requirements	**$ 249,423,765**

Q. WILL THE CACJA RIDER AND TCA CONTINUE AFTER THE REVENUE REQUIREMENTS ABOVE HAVE BEEN TRANSFERRED INTO BASE RATES?

A. Yes. As I explain in more detail below, the TCA will remain in place going forward, and the CACJA Rider will remain in place through December 31, 2021 to allow for necessary CACJA cost recovery true-ups for calendar years 2018 and 2019. In addition, Production Tax Credits ("PTCs") for the Rush Creek Wind Project will continue to be collected through the ECA, as will capital cost savings sharing once the level of such sharing is determined, as explained in more detail by Ms. Trammell.

A. CACJA Rider

Q. WHAT IS THE CACJA RIDER?

A. The CACJA Rider was approved in Proceeding No. 14AL-0660E by Decision No. C15-0292. The rider allows the Company to recover both capital and O&M associated with eligible CACJA projects in accordance with the settlement agreement approved by the Commission in Decision No. C15-0292. Costs for eligible CACJA projects must have been incurred and associated with an investment that went into service between August 1, 2014 and December 31, 2017. Consistent with Decision No. C15-0292, our tariff provides that revisions to the CACJA Rider will be accomplished through an advice letter filing no later than November 1 of each year to take effect on the following January 1. The annual advice letter filed each November 1 includes our forecasted revenue requirement for the upcoming calendar year, plus the CACJA Rider True-Up from two calendar years prior. Accordingly, our November 1, 2018 CACJA Rider Advice Letter No. 1777,[8] implementing CACJA Rider rates for calendar year 2019, included our forecasted CACJA Rider revenue requirement for calendar year 2019, and our CACJA Rider True-Up for calendar year 2017. Similarly, per the settlement agreement, the Company files a report each April that summarizes actual expenditures and variances that result in true-ups, as I explain below.

[8] Proceeding No. 18AL-0768E.

Q. WHAT CACJA RIDER REVENUE REQUIREMENT IS THE COMPANY PROPOSING TO TRANSFER TO BASE RATES?

A. The Company is proposing to include the revenue requirement associated with the CACJA Rider that is included in the 2018 HTY cost of service study presented by Ms. Blair. The specific amounts are listed in Table MMA-D-1 above and also in Ms. Blair's Attachment DAB-12. As discussed by Ms. Blair, the revenue requirement presented on Attachment DAB-12 includes the impact of the previously-approved change in the depreciation rates on the Company's CACJA assets[9].

Q. WHY IS THE COMPANY PROPOSING TO TRANSITION THE COST RECOVERY FOR CACJA PROJECTS INTO BASE RATES AS PART OF THIS CASE?

A. The implementation of our CACJA compliance plan under the Clean Air-Clean Jobs Act is virtually complete. The Company is therefore proposing to transfer to base rates its investment in CACJA projects. As I stated, Table MMA-D-1 above shows the 2018 HTY revenue requirement associated with the CACJA Rider ($78,719,151) that the Company is proposing to roll into base rates as of January 1, 2020. While the Company proposes to transfer to base rates the 2018 HTY revenue requirement, the CACJA Rider will continue to exist

[9] *See* 2016 Depreciation Case, Proceeding No. 16A-0231E, Decision No. R16-1143 (Mailed Dec. 13, 2016), which is discussed in detail by Company witness Ms. Laurie J. Wold.

through December 31, 2021 to allow for necessary CACJA Rider cost recovery true-ups for calendar years 2018 and 2019.

Q. ARE ANY OF THE CACJA PROJECT COSTS IN THE REVENUE REQUIREMENT INCLUDED IN TABLE MMA-D-1 CURRENTLY BEING RECOVERED IN BASE RATES?

A. No, with one exception. All of the Company's CACJA project costs are being recovered through the CACJA Rider. However, due to the use of an HTY (calendar year 2013) to establish base rates as part of the settlement agreement in the Company's last electric rate case (Proceeding No. 14AL-0660E), some of the variable non-fuel O&M expenses for Cherokee Unit 3 have historically been included in base rates. These costs are shown in the CACJA Rider revenue requirement as a reduction to total O&M to prevent double-recovery and to ensure that all of the savings due to the shutdown of Cherokee Unit 3 are accruing to the benefit of our customers.

Q. WHY ISN'T THE COMPANY PLANNING TO DISCONTINUE THE CACJA RIDER UNTIL DECEMBER 31, 2021?

A, As I explained above, when we make our CACJA Rider filing through an advice letter each November 1, we adjust the revenue requirement recovered through the CACJA Rider based on the forecasted revenue requirement for the upcoming calendar year. We also true-up the actual revenue requirement and revenue recovered through the rider for the calendar year two years prior. Accordingly, when the revised CACJA Rider rates go into effect each January 1, they are based on a revenue requirement calculation that includes a true-up for the actual revenue requirement and revenue recovered through the rider two calendar years previous.

To illustrate, Advice Letter No. 1777 filed on November 1, 2018, established revised CACJA Rider rates for calendar year 2019 based on our forecasted CACJA Rider revenue requirement for 2019 and a true-up of actual revenue requirement and revenue previously recovered under the CACJA for calendar year 2017. Accordingly, the CACJA Rider must remain in place through the end of calendar year 2021 to true-up the revenue requirement and revenue collected through the CACJA Rider for calendar year 2019.

Q. HOW WILL THE CACJA RIDER OPERATE BEGINNING WITH THE EFFECTIVE DATE OF RATES FROM THIS CASE?

A. The CACJA Rider will be set to zero effective with the base rate change in this case, except for any true-ups from prior years (as I explained above). The Company will file to update its current CACJA Rider, effective January 1, 2020 ("2020 CACJA Rider"), in November 2019. However, as described by Ms. Trammell, the Company is requesting that base rates from this rate review become effective January 1, 2020, assuming the Commission suspends the Advice Letter.[10] Once base rates are effective in 2020, the 2020 CAJCA Rider will need to be set to zero, except for any true-ups from prior years that are included in the 2020

[10] As described in more detail by Ms. Blair, the 2020 CACJA Rider will be calculated 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-up.

CACJA Rider, in order to prevent double recovery. Effective January 1, 2021, the CACJA Rider will only include the true-up for calendar year 2019, and the CACJA Rider tariff will then be cancelled effective January 1, 2022 through a compliance advice letter filing.

Q. WILL THE COMPANY HAVE ONGOING CACJA OBLIGATIONS AFTER THE CACJA RIDER IS TRANSFERRED TO BASE RATES?

A. Yes. As I indicated, under the Company's proposal, the CACJA Rider will only continue after the effective date of new rates in this proceeding for true-ups for the period prior to the roll-in of the CACJA Rider. The CACJA true-ups consist of three components: (1) the difference between the forecasted revenue requirement and the actual revenue requirement; (2) the difference between the revenue the rider was designed to recover and the actual dollars collected; and (3) interest on the monthly over- or under-recoveries. All other CACJA costs that would have historically been recovered through the rider will be included in the Company's base rates.

Q. WILL THE COMPANY CONTINUE TO PROVIDE ROBUST TESTIMONY THAT HAS BEEN PROVIDED IN PAST APRIL CACJA REPORTS FOR THE FINAL APRIL 2020 CACJA REPORT?

A. Yes.

B. TCA

Q. TURNING NOW TO THE TCA, PLEASE PROVIDE ADDITIONAL DETAIL ON HOW THE TCA OPERATES.

A. The TCA, established by statute (C.R.S. § 40-5-101(4)) and tariff, provides for recovery of retail jurisdiction transmission function costs. In Proceeding No. 07A-339E,[11] the Commission approved the Company's implementation of its TCA. The TCA includes an annual true-up to reflect the actual net plant and Construction Work in Progress ("CWIP") balances as of year-end as compared to projected balances. The annual true-up also addresses revenue recovered through the TCA. Each November 1, the Company files an advice letter to update the revenue requirement recovered through its TCA and the associated rates to be charged under the TCA commencing the following calendar year. This annual advice letter filing accomplishes the true-up noted above for the prior full calendar year. As we are proposing in this case, when the Company establishes new base rates in a full rate proceeding, a portion of the revenue requirement being recovered through the TCA is typically transferred to base rates. That base level of TCA costs is then used to calculate the rider moving forward. For instance, the settlement agreement approved by Decision No. C15-0292 in Proceeding No. 14AL-0660E adjusted the Company's TCA rate and reset the base amount used to calculate the TCA in future years.

[11] Decision No. C07-1085 (mailed Dec. 24, 2007).

Q. WHAT TCA REVENUE REQUIREMENT IS THE COMPANY PROPOSING TO TRANSFER TO BASE RATES?

A. The Company is proposing to include the revenue requirement associated with the TCA that is included in the 2018 HTY cost of service study presented in this case. That revenue requirement, $40,027,376, is shown in Table MMA-D-1 above and also in Ms. Blair's Attachment DAB-14, page 1. The 2018 annual 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 case.

Q. WHAT DOES THE COMPANY PROPOSE WITH REGARD TO TRANSFERRING THE TCA RIDER INTO BASE RATES?

A. The Company is proposing to transfer recovery of the TCA revenue requirement associated with the plant in-service balances included in the rate base balances in the 2018 HTY. The Company has been granted rider recovery for transmission investment through the TCA and there is no reason to modify that. Thus, after rates go into effect as a result of this rate review proceeding, the TCA will operate as before, with the 2018 HTY as a baseline.

Q. PLEASE GIVE AN EXAMPLE OF HOW THE TCA WILL OPERATE BEGINNING WITH THE EFFECTIVE DATE OF RATES APPROVED IN THIS CASE.

A. In November 2019, the Company will file to update the TCA, effective January 1, 2020 ("2020 TCA").[12] A portion of the amounts included in the 2020 TCA are also included in the 2018 HTY cost of service in this case. Once base rates are effective from this case, the 2020 TCA must be reduced effective with the base rate change in this case (as discussed above proposed by the Company in the event of a suspension to be January 1, 2020) in order to prevent double recovery. After the effective date of the base rate change, the 2020 TCA and future TCA Rider filings will reflect the TCA costs in base rates in the 2018 HTY until the next base rate case. The 2020 TCA and all subsequent TCA filings would include any true-up from prior TCA years.

C. <u>Rush Creek Wind Project</u>

Q. PLEASE PROVIDE SOME BACKGROUND REGARDING THE RUSH CREEK WIND PROJECT.

A. The Rush Creek Wind Project is a Company-owned, 600 MW wind generation facility and associated Gen-Tie east of Colorado Springs. The commercial operation date of the Project was December 7, 2018. In Proceeding No. 16A-0117E, Decision No. C16-0958, the Commission approved a settlement

[12] As described in more detail by Ms. Blair, 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 (just as it would have had this case not been filed).

agreement providing for the Company's construction and ownership of the Rush Creek Wind Project ("Rush Creek CPCN Settlement").

Q. PLEASE EXPLAIN HOW COSTS FOR THE RUSH CREEK WIND PROJECT ARE CURRENTLY BEING RECOVERED.

A. In the Rush Creek CPCN Settlement approved by the Commission, the settling parties agreed that the initial cost recovery for the Rush Creek Wind Project would be through the ECA and RESA until such time as the Company filed a base rate case following the commercial operation date of the facilities. To date, cost recovery has only been through the ECA. As indicated above, the commercial operation date of the Project was December 7, 2018. Accordingly, we are now proposing to roll these Rush Creek Wind Project costs into base rates.

Q. WHAT IS THE COMPANY PROPOSING IN THIS CASE WITH RESPECT TO THE ONGOING COST RECOVERY OF THE RUSH CREEK WIND PROJECT?

A. Consistent with the Rush Creek CPCN Settlement, we are proposing to transition cost recovery from the ECA to base rates, beginning January 1, 2020, with the exception of the PTCs, which will continue to flow through the ECA as described below, and capital cost savings sharing amounts addressed by Ms. Trammell.

Q. WHAT IS THE COMPANY PROPOSING TO TRANSFER TO BASE RATES WITH RESPECT TO THE RUSH CREEK WIND PROJECT?

A. The Company is proposing to include the revenue requirement associated with the Rush Creek Wind Project that is included in the 2018 HTY cost of service study presented in this case. The revenue requirement associated with the Rush Creek Wind Project included in the 2018 HTY, $130,677,238, is shown in Table MMA-D-1 above and also in Ms. Blair's Attachment DAB-12. The revenue requirement presented on Attachment DAB-12 includes the impact of the requested depreciation rate for the Rush Creek Wind Project, as described by Ms. Wold.

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

A. Yes. Ms. Blair describes the property taxes and property insurance costs that the Company has been recovering through base rates, as opposed to the ECA or RESA. Company witness Ms. Naomi Koch provides additional detail regarding the adjustment to the 2018 HTY for Rush Creek Wind Project property taxes.

Q. WILL ALL COSTS ASSOCIATED WITH THE RUSH CREEK WIND PROJECT BE INCLUDED IN BASE RATES SUBSEQUENT TO JANUARY 1, 2020?

A. No. The cost savings and benefits of the PTCs will continue to be credited to customers through the ECA as set forth in the Rush Creek CPCN Settlement.

Q. PLEASE GIVE AN EXAMPLE OF HOW THE ECA WILL OPERATE WITH RESPECT TO THE RUSH CREEK WIND PROJECT BEGINNING WITH THE EFFECTIVE DATE OF RATES FROM THIS CASE.

A. The Company will file to update the ECA, effective January 1, 2020 ("2020 ECA") in December 2019.[13] Once base rates are effective in 2020, the 2020 ECA will need to be adjusted to remove Rush Creek Wind Project from the calculation with the base rate change in this case, in order to prevent double recovery. In addition, the 2020 ECA and all subsequent ECA filings would include any true-up from prior ECA years.

Q. HOW DOES ROLLING IN THE REVENUE REQUIREMENTS FROM THE CACJA RIDER, TCA, AND RUSH CREEK WIND PROJECT IMPACT BASE RATES?

A. As discussed in Ms. Trammell's Direct Testimony, based on our proposed total revenue requirement, including the 2018 HTY revenue requirements associated with the CACJA Rider, TCA, and Rush Creek Wind Project discussed above, the Company's proposed increase in Total Base Revenue including Roll-Ins, effective January 1, 2020, is $401,737,776. However, in terms of the drivers of our overall rate request, 61.2 percent of the increase ($249,423,765) in base rates is attributable to rolling into base rates the CACJA Rider, TCA, and Rush Creek Wind Project revenue requirements, and thus is not really an increase at

[13] As described in more detail by Company witness Ms. Blair, the 2020 ECA will include 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.

all, but just a change in recovery mechanism. After considering the effects of transferring recovery of certain items to base rates from rider recovery, the Company is requesting a net increase in overall base rate revenue of $158,314,011, or 10.3 percent, over adjusted current base rate revenue. In other words, the Company's requested revenue requirement increase is actually far less than it appears, since a portion of it is associated with the shift of the CACJA Rider, TCA, and Rush Creek Wind Project revenue requirements from riders into base rates. Moreover, and as explained by Ms. Trammell in her Direct Testimony and its Attachment BAT-1, the Company's Steel for Fuel strategy and trends in the industry toward renewable resources that can save money for customers require a different vantage point when it comes to evaluating customer impacts. Ms. Trammell notes that it is important to look at the total bill impact for customers of this rate request, which reflects customer savings of the Steel for Fuel initiative. Attachment BAT-1 provides this overall look at how the Company's total revenues are shifting and then reflects that total bill, as opposed to a base rate-only, look for customers, with a customer impact of 5.7 percent. This 5.7 percent data point is an appropriate metric on a total bill basis for use in evaluating the Company's rate proposal in this proceeding.

III. TARIFF REVISIONS

A. Introduction

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

A. In this section of my Direct Testimony, I review all of the revisions that we propose to our electric tariffs in the proceeding. Clean and redlined versions of all tariff sheets are included as Attachments MMA-1 and MMA-2, respectively.

Q. HOW IS THIS SECTION OF YOUR DIRECT TESTIMONY ORGANIZED?

A. I divide this section of my Direct Testimony into three sections. First, I address the proposed General Rate Schedule Adjustment ("GRSA"). Second, I discuss tariff changes where we are making fairly minor changes to a tariff sheet (e.g., updating the Table of Contents). Attachment MMA-3 provides a table summarizing these tariff changes. Third, I address tariff changes that are more substantial, including revisions to the specific terms and conditions of certain tariffs, or changes to general language.

Q. AS A PRELIMINARY MATTER, IS THE COMPANY PROPOSING A GRSA?

A. Yes. The Company is proposing two GRSAs as part of this rate review, first a GRSA that reflects the Company's cost of service and second, a "GRSA-E" that reflects the Rush Creek Wind Project costs on an energy basis. Company witness Ms. Blair explains that 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, which is designed to collect approximately $130 million of energy-specific charges associated with the Rush Creek Wind Project. The base rate kWh charge will be known as the "GRSA-E" rider and is a separate GRSA for the Rush Creek Wind Project. The proposed GRSA, which is reflected in Attachments MMA-1 and MMA-2, would be an incremental increase to the current base rates approved in the last electric Phase II Rate Case, Proceeding No. 16AL-0048E. Past rate proceedings have often included a separate "Phase I" for the determination of a revenue requirement, and "Phase II" for rate design and cost allocation, and the GRSA has functioned to allow Public Service to implement a Commission-approved change to base rates, across all rate classes, during the period following a Phase I determination but before the completion of a Phase II rate design proceeding. At present, the Company's GRSA is negative 4.19 percent[14] to implement rate reductions associated with the return of 2018 Tax Cuts and Jobs Act ("TCJA") savings.

In this Phase I proceeding, based on the timing and proposed effective date of final rates, we anticipate that our GRSA will be implemented at the end of this case effective January 1, 2020. This proposal is discussed further by Company witness Ms. Trammell.

[14] There is also a negative -0.44 percent GRSA effective April 1, 2019 through June 30, 2019 as a result of the Revised Stipulation and Settlement Agreement Regarding Incorporating Tax Cuts and Jobs Act ("TCJA") Impacts into Public Service's Rates ("Revised TCJA Settlement") filed on April 27, 2018. Under the terms of the Revised TCJA Settlement, Public Service agreed to make a compliance filing within 60 to 90 days after the end of 2018 to true up the 2018 TCJA impacts for variances in estimated revenues. This GRSA will be in effect until June 30, 2019.

B. Tariff Sheet Rate Changes and Other Minor Revisions

Q. IS THE COMPANY MAKING MINOR CHANGES TO CERTAIN TARIFF SHEETS?

A. Yes. Among other changes, we are updating the Table of Contents based on the changes we are making to other tariffs, and we are similarly updating the Reserved for Future Filing Index, Territory Served, and General Definitions. In addition, the Company is removing the reference to Transmission Time-of-Use (Schedule TTOU) since the Commission approved the Company's proposal to eliminate the TTOU Schedule as of January 1, 2017.[15] This tariff clean-up impacts Schedules PTOU, STOU, Solar Rewards, DSMCA, PCCA, TCA, and CACJA. Finally, the Company is correcting the wattage from 69 to 65 Watts in the Parking Lot Lighting Service (Schedule PLL).

C. Tariff Revisions Involving Changes to Terms and Conditions or Other Tariff Language

Q. PLEASE IDENTIFY SOME OF THE OTHER TARIFF REVISIONS THAT INVOLVE CHANGES TO TERMS AND CONDITIONS OR OTHER TARIFF LANGUAGE?

A. The Company proposes changes to specific terms and conditions or other tariff language for the following tariffs:

[15] Decision No. C16-1075 approved the Company's Non-Unanimous Settlement Agreement in Proceeding Nos. 16AL-0048E, 16A-0055E, and 16A-0139E, effective January 1, 2017.

- Earnings Share Adjustment (“ESA”)
- Quality of Service Plan (“QSP”)
- Electric Commodity Adjustment
- Clean-Air Clean-Jobs Act Rider
- Requests for Customer Data in Rules and Regulations - General
- Other Meter Tests and Billing for Errors in Rules and Regulations - Standards

Q. DO SOME OF THE COMPANY’S PROPOSED CHANGES ALSO INCLUDE CHANGES TO APPLICABLE RATES OR CHARGES?

A. Yes, while some of these revisions involve proposed changes to specific terms and conditions or other tariff language, others involve changes to tariff language and the applicable rates or charges. For the latter category, because they also include tariff language changes, I cover them here, as opposed to the prior section of my Direct Testimony that addressed only very minor modifications.

Q. PLEASE BRIEFLY DESCRIBE THE CHANGES TO EACH OF THE TARIFFS INCLUDED IN THIS SECTION OF YOUR TESTIMONY AND WHY THE COMPANY IS PROPOSING THESE CHANGES.

A. In the following subsections, I provide an overview of the changes to the applicable tariffs, discuss the Company’s reasons for proposing these changes, and explain why such changes are reasonable and should be approved by the Commission.

1. <u>Earnings Share Adjustment</u>

The ESA is being removed from the Company’s tariff as it expired in 2017 and is not part of the Company’s proposal in this proceeding.

2. Quality of Service Plan

The QSP was originally established in January 1, 2007, and the Company filed Advice Letter No. 1779-Electric to extend the existing QSP on November 13, 2018. At this time, the Company proposes only minimal adjustments to the QSP. However, certain other adjustments related to the structure of the overall Gas QSP will likely be made to the Electric QSP depending on the outcome of both the consolidated electric and gas distribution line extension proceeding[16] and the Gas QSP proceeding. These would include alignment of the Company goals and mission of the PUC as well as the addition of adequate service metrics, similar to those described in its New Gas QSP Application and settlement agreement,[17]. The Company intends to include some of the new components of its proposed Gas QSP and the Distribution Line Extension Policy in the Electric QSP pending the outcome of the both proceedings, in which final tariffs are expected no later than this fall.

The Company will submit a compliance filing reflecting the outcome of the consolidated line extension proceedings that will remain in the Electric QSP through 2021. For present purposes, as reflected in the redlined tariff sheet included in Attachment MMA-2, the Company is proposing to extend the Electric QSP through 2021, and to modify the reporting requirements to replace current monthly, quarterly, and annual reporting with just annual reports. The Electric QSP is well-established, and the Company believes that annual reporting is

[16] *See* Proceeding No. 18AL-0852E.
[17] *See* Proceeding No. 18A-0918G.

adequate and more administratively efficient, and that this change will streamline the process for both the Company and other stakeholders. The inclusion of structural changes and the addition of adequate service metrics, when finalized and approved in the Gas QSP and consolidated line extension proceedings, will maintain consistency as between the Gas and Electric QSPs, and is consistent with the Company's objectives to improve transparency and customer service.

3. <u>Electric Commodity Adjustment</u>

The Company is proposing to update the Short-Term Sales Margins for Generation and Proprietary Book from calendar year 2015 to 2018. Company witness Ms. Blair explains the basis for these changes to the sales margins in more detail in her Direct Testimony.

The ECA is also being revised to move recovery of the revenue requirement associated with the Rush Creek Wind Project from the ECA into base rates, as I described previously in my testimony. The cost savings and benefits of the PTCs, however, will continue to be credited to customers through the ECA as well as any capital cost savings sharing as set forth in the Rush Creek CPCN Settlement.

Additionally, I propose to implement tariff language in the ECA associated with the Cheyenne Ridge Wind Project Settlement Agreement approved by Commission Decision No. C19-0367E in Proceeding No. 18A-0905E, which provides for recovery through the ECA of the costs of the Cheyenne Ridge Wind Project, including the revenue requirement, deferred tax asset carrying costs and PTCs as applicable. The revenue requirement, with the exception of any incremental costs associated with the Cheyenne Ridge Wind Project, will flow through the ECA until such a time that the revenue requirement is rolled into base rates.

Finally, the Company proposes to discontinue the existing Equivalent Availability Factor Performance Mechanism. The EAFPM applied to the Company's Equivalent Availability Factor ("EAF") performance in 2015, 2016 and 2017. I explain the EAFPM proposal in more detail later in my Direct Testimony.

4. <u>Clean Air-Clean Jobs Act Rider</u>

As I discussed earlier in my Direct Testimony, we are proposing to roll into base rates the 2018 HTY revenue requirements that are currently recovered through the CACJA Rider. The CACJA Rider will only continue after the effective date of new rates in this proceeding for true-ups for the period prior to the roll-in of the CACJA Rider. The CACJA Rider will remain in place through December 31, 2021 to allow for necessary CACJA cost recovery true-ups for calendar years 2018 and 2019. We will submit an additional annual filing on or around April 15, 2020 for purposes of the true-up of CACJA costs in base rates, as explained earlier in my testimony.

The Company modified the CACJA Rider tariff to explain that the last advice letter will be filed by November 1, 2020 to take effect January 1, 2021. Additionally, the Company will submit a compliance advice letter filing to cancel the CACJA Rider tariff effective January 1, 2022.

5. Data Privacy and Requests for Customer Data

The Company is proposing tariff changes related to Data Privacy in the Requests for Customer Data section of the General section of the Company's Rules and Regulations. The Company's main Data Privacy provisions are found starting on Sheet No. R95. Now that the Company has several years' experience implementing the Commission's customer data privacy rule requirements, the Company is proposing tariff changes to more clearly reflect the reports available to customers and third parties, and associated parameters and charges. Along with these proposed changes, the Company has proposed changes to the Schedule of Charges for Rendering Service, on Sheet No. 25B, to reflect the reduced charge of $291 for Non-Standard Batched Customer Data Reports, along with a new $65 per hour charge for Non-Standard Aggregated Data Reports, as to conform the language to support the changes above. Similarly, on Sheet No. R12, the proposed tariff changes reflect those customer data reports that are provided at no charge.

6. <u>Other Meter Tests and Billing for Errors</u>

In both the Other Meter Tests and Billing for Errors sections of the Standards in the Company's Rules and Regulations, the Company is proposing a number of changes in order to clarify and simplify the tariff language, and better align it with Commission Rules. In addition, the Company proposes to include tariff provisions addressing customer credit and payment plan options that apply in the event billing adjustments are made pursuant to these sections.

IV. RATE CASE EXPENSES

Q. WHAT IS THE TOTAL AMOUNT OF RATE CASE EXPENSES FOR WHICH THE COMPANY SEEKS RECOVERY IN THIS PROCEEDING?

A. The Company seeks to recover $7,669,077 in rate case expenses in this proceeding. These expenses stem from a number of proceedings, including this rate review proceeding.

Q. IS PUBLIC SERVICE PROPOSING TO RECOVER RATE CASE EXPENSES FROM OTHER PROCEEDINGS IN THIS CASE?

A. Yes. Public Service is proposing to include rate case expenses from the Company's 2017 Electric Rate Case,[18] 2016 Depreciation Case in Proceeding No. 16A-0231E, and 2016 Phase II Case in Proceeding No. 16AL-0048E.

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

A. Most businesses have the flexibility to set their prices based on their assessment of the market and the demand for their products. Utilities subject to cost of service regulation do not have this same flexibility. Instead, we must file for and obtain regulatory authorization to establish new rates. Consequently, the cost of filing and litigating rate cases are necessary costs of conducting our business. It has been the long-standing practice of this Commission to treat reasonable rate

[18] The 2017 Electric Rate Case 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.

case expense as a necessary cost of doing business and, after review, to allow recovery of rate case expenses through mechanisms established in the same or subsequent proceedings.

Q. WHY IS PUBLIC SERVICE INCLUDING RATE CASE EXPENSES FOR THE 2017 ELECTRIC RATE CASE IN THIS PROCEEDING?

A. The 2017 Electric Rate Case was filed pursuant to both administrative and legislative directives. First, when the Commission approved the Settlement Agreement in the 2014 Electric Rate Case establishing our current electric retail rates, it directed the Company to file "an electric base rate case in 2017 for rates to be in effect no sooner than January 1, 2018 …."[19] The Colorado Public Utilities Law required the filing in 2017 as well. Specifically, the Company needed to file a base rate case before the end of the rate period established by the Settlement Agreement given that the rates included the CACJA Rider, which is a "special regulatory practice" within the meaning of § 40-3.2-207(5), C.R.S. Section 40-3.2-207(5), C.R.S. requires that "[d]uring the time any special regulatory practice is in effect, the utility shall file a new rate case at least every two years or file a base rate recovery plan that spans more than one year." Therefore, the Company made the 2017 Electric Rate Case filing consistent with both the requirements of Decision No. C15-0292 and § 40-3.2-207(5), C.R.S.

[19] Decision No. C15-0292, at Ordering ¶ 6.

Q. WHY IS PUBLIC SERVICE INCLUDING RATE CASE EXPENSES FOR THE 2016 DEPRECIATION STUDY IN THIS PROCEEDING?

A. Under the terms of the approved Settlement Agreement from Public Service's 2014 Electric Rate Case, the Company is allowed to include incremental outside consultant and legal expenses incurred by the Company in preparing and defending the 2016 Depreciation Case.

Q. WHY IS PUBLIC SERVICE INCLUDING RATE CASE EXPENSES FOR THE LAST PHASE II ELECTRIC RATE CASE IN THIS PROCEEDING?

A. Under the terms of the three-case Settlement Agreement (at page 45) from Public Service's Phase II Electric Rate Case in Proceeding No. 16AL-0048E,[20] which was approved by the Commission in Decision No. C16-1075 (as modified by Decision No. C16-1165), the Company is allowed to include actual rate case expenses as eligible for recovery in the next Electric Phase I rate case.

In addition, also pursuant to this agreement, any additional programming and billing costs for the RE-TOU and RD-TDR above the incremental metering costs of the service and $330,000 of one-time programming and billing costs shall be treated as rate case expenses eligible for deferred accounting and recovery in a subsequent proceeding ("2016 Phase II Trial and Pilot"). This rate review proceeding is that proceeding.

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[20] Proceeding Nos. 16AL-0048E (Public Service's Phase II Electric Rate Case), 16A-0055E (Public Service's Application for Approval of the Solar*Connect Program), and 16A-0139E (Public Service's Application for Approval of the 2017-2019 Renewable Energy Compliance Plan) were combined for purposes of settlement.

Q. PLEASE PROVIDE A MORE DETAILED BREAKDOWN OF THE TOTAL AMOUNT OF RATE CASE EXPENSES THE COMPANY SEEKS TO RECOVER IN THIS PROCEEDING.

A. The total cost for this rate review proceeding, the 2017 Electric Rate Case, the 2016 Depreciation Study, and the 2016 Phase II Rate Case (including the 2016 Phase II Trial and Pilot) are as follows:

Table MMA-D-2
Total Rate Case Expenses

Proceeding Name	***Proceeding No.***	***Amount***	***Expense Type***
2019 Rate Review	This proceeding	$ 1,470,241	Estimate
2017 Electric Rate Case	17AL-0649E	$ 987,507[21]	Actuals
2016 Depreciation Case	16A-0231E	$ 583,474	Actuals
2016 Phase II Rate Case	16AL-0048E	$ 380,067	Actuals
2016 Phase II Trial and Pilot	16AL-0048E	$ 3,822,755 / 4,247,788	Actuals/Estimate
Total		**$7,669,077**	

The total cost for consultants, legal expenses, and other initiatives associated with this Phase I rate review is estimated to be $1,470,241, assuming a fully litigated case with a hearing, post-hearing briefing, exceptions and replies to exceptions, and motions for rehearing and replies. The actual costs for the 2017 Electric Rate Case ($987,507) as adjusted to remove costs associated with TCJA Quarterly Reports), 2016 Phase II Rate Case ($380,067), and the 2016 Depreciation Case ($583,474) are primarily associated with consultants and legal expenses that were incurred for these proceedings. The 2016 Phase II Trial and

[21] This amount is $1,001,719 less $14,211 for TCJA Quarterly Reports that have been removed from this rate case expense amount.

Pilot are currently underway and the associated marketing, program management, measurement and verification ("M&V"), billing and IT costs are estimated to be $4,247,788. Attachment MMA-4 provides a summary of these rate case expenses by major category and proceeding.

Below I discuss some rate case expense history and explain the major categories of the rate case expenses.

Q. DOES YOUR ESTIMATE OF RATE CASE EXPENSES INCLUDE ANY RATE CASE EXPENSES FROM THE 2014 ELECTRIC RATE CASE?

A. No. As detailed by Company witness Ms. Blair, the rate case expenses approved for the 2014 Electric Rate Case were amortized over a 36-month period, which ended December 31, 2017.

Q. PLEASE LIST AND GENERALLY DESCRIBE THE MAJOR RATE CASE EXPENSE CATEGORIES YOU ARE PRESENTING FOR RECOVERY.

A. The major categories of rate case expenses are generally common to each of the proceedings for which the Company seeks recovery of rate case expenses, and I provide expenses for these categories in Attachment MMA-4:

Consultants: Consultants are necessary for the preparation of a comprehensive electric rate case for a number of reasons. Many times consultants will testify to or provide support for ROE recommendations, benchmarking analyses, actuarial review of testimony, discovery, or case assembly. Typically, the expertise sought from the consultant is not an expertise that is hired on a permanent basis within the organization.

Transcripts/Hearing Costs: During the course of a proceeding, a court reporter will be necessary to transcribe depositions and hearings before the Commission. There is a cost of having court reporters record and transcribe these proceedings. This fee increases or decreases based upon the timeframe by which the reporter must turn over the transcript.

Legal Counsel: The Company has an in-house legal department whose regulatory team works on the matters that we have before the Commission. However, we have more Commission-related work than can be handled by our in-house department, so we also need to retain outside attorneys for this work. The Company does not staff up its legal department assuming continuous ongoing rate cases, but we do assign inside attorneys to our rate cases. Our ability to rely on our inside counsel for rate cases is dependent upon other pending matters. Therefore, outside legal assistance is sometimes necessary.

Customer Noticing: Pursuant to Rule 1210, the Company must provide a notice to its customers regarding the rate request. Historically this meant sending out a mailing to all customers at a substantial cost. During the 2014 Electric Rate Case, we reached an agreement on noticing and filed that alternative form of notice ("AFN") with the Commission. We are proposing to utilize that same procedure here.

Postage: We must occasionally mail case materials to intervenors (e.g., Company testimonies, discovery responses, and other materials).

Duplicating and Office Supplies: This category of costs reflects the printing of our filings for internal and external use, as well as other materials necessary for the rate case.

Miscellaneous Expenses: This category captures a variety of items, including market research, incremental regulatory support from temporary or hourly employees for the preparation and processing of the case, and travel and related expenses for Company witnesses to attend the hearing and other meetings.

A. This Rate Review Proceeding

Q. WILL PUBLIC SERVICE INCUR RATE CASE EXPENSES TO PREPARE AND PROSECUTE THIS RATE REVIEW?

A. Yes. Public Service has already incurred rate case expenses to prepare this rate review filing and will continue to incur rate case expenses to perform the other tasks necessary as we move through the adjudicatory process before the Commission.

Q. PLEASE DISCUSS THE ACTUAL RATE CASE EXPENSES THAT PUBLIC SERVICE INCURRED RELATED TO THIS RATE REVIEW PROCEEDING THROUGH THE END OF THE APRIL 2019.

A. Public Service incurred $469,117 in rate case expenses related to this rate review proceeding through the end of April 2019. These expenses were incurred primarily due to consultant expenses, legal fees, and internal labor expenses.

Q. PLEASE DISCUSS THE SPECIFIC CONSULTANT AND OUTSIDE WITNESS COSTS THAT THE COMPANY IS PROJECTING TO INCUR FOR THIS PHASE I RATE CASE.

A. The costs associated with securing outside consultants or witnesses with specific areas of expertise are necessary for the support and completion of the case. We estimate these costs to be $156,133 for the services provided by Concentric and Willis Towers Watson.

Q. PLEASE DESCRIBE THE SERVICES THAT WERE OR WILL BE PROVIDED BY CONCENTRIC ENERGY ADVISORS.

A. In any rate review, ROE and capital structure are critical issues. The witness developing the ROE recommendation must be experienced and able to explain the analysis clearly. We do not maintain the expertise required of an ROE witness in-house. Consequently, we must hire a consultant to provide the analysis and testimony. The Company does not hire an internal witness for this area of expertise because it is a specialized field. Moreover, external experts generally have a broader view of developments in their areas of expertise than internal employees focused on the eight states in which Xcel Energy operates. Rate cases expenses for services provided by Concentric Energy Advisors is approximately $130,000.

Q. PLEASE DESCRIBE THE SERVICES THAT WERE OR WILL BE PROVIDED BY WILLIS TOWERS WATSON.

A. Willis Towers Watson is providing consulting support to the Company with both a compensation study and assistance related to the Company's pension plan status. $26,133 of the rate case expenses is estimated to be for Willis Towers Watson, with $25,000 for the compensation study and $1,133 for the pension-related analyses.

Q. PLEASE DISCUSS THE TRANSCRIPT AND HEARING COSTS THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REVIEW.

A. The Company anticipates incurring a total cost of $26,025 for the purchase of transcripts of the hearings and other hearing costs.

Q. PLEASE DISCUSS THE OUTSIDE LEGAL FEES THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REVIEW.

A. Outside Legal costs are estimated to be $1,170,000, which are separated across two law firms we hired for specific assistance with this rate review proceeding. The two law firms are Winstead PC and Wilkinson Barker Knauer LLP. Each of these firms was retained for its expertise and specific knowledge of Public Service and other Xcel Energy operating companies. The firms provided, or will provide, assistance in assembling testimony and attachments, witness preparation, advice on strategy, responding to discovery, and generally processing the case. I would also add that the Company's internal legal team works hard to ensure that duties are appropriately assigned to outside legal counsel and to ensure that work efforts are not duplicative. The internal and external legal teams work as a unit and are in constant coordination to be as efficient as possible.

Q. PLEASE DESCRIBE THE COSTS TO MEET THE NOTICE REQUIREMENTS OF THE COMMISSION THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REVIEW.

A. The costs estimated for completing this requirement are $55,074. This cost can be broken down into two categories: (1) bill insert; and (2) newspaper. The bill insert component of this category of rate case expense is $19,480, which is the cost associated with printing the notice on a customers' bills and mailing it to customers during their normal billing cycles. The newspaper component of this category of rate case expense is $35,594. This expense is to fulfill the requirement that we post the notice of our filing in a newspaper of general circulation for two consecutive Sundays.

Q. PLEASE DISCUSS THE POSTAGE COSTS THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REVIEW.

A. We estimate we will incur approximately $500 in postage expenses throughout the case. These are costs associated with providing materials such as discovery responses to intervening parties through the United States Postal Service delivery or direct shipping. If materials need to be mailed to an intervenor, the Company prefers to use the United States Postal Service delivery. However, in some cases the only means of timely delivery is direct shipping.

We again plan to use the SharePoint site to provide access to discovery responses, attachments, work papers, testimony, and some settlement materials. This approach both reduces postage costs and allows intervenors located at a more distant location to more timely access the information.

Q. PLEASE DESCRIBE THE ESTIMATED COSTS ASSOCIATED WITH THE PRINTING AND PROVISION OF HARD COPIES OF CASE MATERIALS FOR THIS RATE REVIEW.

A. Both at the onset of the case and throughout the proceeding, the Company will provide paper copies to various parties as well as to Company witnesses. The costs for this activity are estimated to be $1,200 for printing and $500 for supplies.

Q. PLEASE DISCUSS THE MISCELLANEOUS EXPENSES THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THIS RATE REVIEW.

A. Miscellaneous expenses cover communications with our employees regarding the rate review, travel expenses for out-of-state witnesses and incremental regulatory support. The total amount requested for this category is $60,809, which is broken down into sub-categories below.

Table MMA-D-3
Miscellaneous Expenses for Current Proceeding

Miscellaneous Expenses	***Amount***
Communications – Webcast	$ 1,545
Employee Expenses (e.g. Travel)	$ 17,600
Regulatory Support	$ 41,664
Total	**$ 60,809**

The two most significant subcategories in this major cost category are Employee Expenses and Regulatory Support. The Employee Expenses subcategory reflects travel expenses for individuals who do not reside in Colorado. These employees must travel to provide testimony at the hearing, meet with intervenors, and participate in other preparatory sessions as needed. Regulatory Support is for the incremental labor that the Company has contracted for eight months to support the case full time. Regulatory Support includes supporting the SharePoint site permissions, tracking discovery requests and responses, and other administrative tasks necessary to manage the case timely and accurately.

B. <u>2017 Electric Rate Case</u>

Q. PLEASE DISCUSS THE OUTSIDE LEGAL FEES THAT THE COMPANY INCURRED FOR THE 2017 ELECTRIC RATE CASE.

A. The Company incurred $668,331 for outside legal costs for the firms Winstead PC, Wilkinson Barker Knauer LLP, and Briggs and Morgan. These firms provided assistance in assembling testimony and attachments, advice on strategy, responding to discovery, and generally processing the case. The outside legal services were retained in order to supplement the Company's in-house legal staff's case load.

Q. PLEASE DISCUSS THE CONSULTANT COSTS THAT THE COMPANY INCURRED FOR THE COMPANY'S 2017 ELECTRIC RATE CASE.

A. The Company incurred $247,961 of consultant costs for PEG, Concentric, Janet Schmidt-Petree (consultant retained by Wilkinson Barker Knauer LLP), and Gene Wickes as broken down further below. PEG provided consulting serviced related to the proposed Multi-Year Plan and benchmarking in support of the test year convention utilized in Proceeding No. 17AL-0649E Concentric provided similar services to the services provided in this proceeding, primarily related to ROE and capital structure. In the 2017 Electric Rate Case, as is the case here, these are critical issues and Concentric and its specialized expertise were retained to assist the Company in addressing these issues. Janet Schmidt-Petree assisted in development of the CAAM and FDC Study brought forward in the 2017 Electric Rate Case and also provided assistance in addressing discovery related to the CAAM and FDC Study. Finally, Mr. Gene Wickes provided consulting services related to the Prepaid Pension Asset.

Table MMA-D-4
Consultant Costs for 2016 Electric Rate Case

Consultant Costs	***Amount***
PEG	$ 167,558
Concentric Energy Advisors	$ 58,106
Janet Schmidt-Petree	$ 13,875
Gene Wickes	$ 8,422
Total	**$ 247,961**

Q. PLEASE DESCRIBE THE COSTS INCURRED TO MEET THE NOTICE REQUIREMENTS OF THE COMMISSION FOR THE 2017 ELECTRIC RATE CASE.

A. The Company incurred $54,874 for noticing the 2017 Electric Rate Case. The bill onsert was $19,280, which is the cost associated with printing the notice on a customers' bills and mailing it to customers during their normal billing cycles. The newspaper notice was $35,594. This expense was to fulfill the requirement that we post the notice of our filing in a newspaper of general circulation for two consecutive Sundays.

Q. WHAT WAS THE AMOUNT OF POSTAGE COSTS THAT THE COMPANY INCURRED FOR THE COMPANY'S 2017 ELECTRIC RATE CASE?

A. The Company projected to incur $500 for postage costs but ultimately did not incur any costs for this category.

Q. PLEASE DISCUSS THE MISCELLANEOUS EXPENSES THAT THE COMPANY INCURRED FOR THE COMPANY'S 2017 ELECTRIC RATE CASE.

A. Miscellaneous expenses cover communications with our employees regarding the rate case, market research, regulatory support, and travel and employee expenses for out-of-state witnesses. For the 2017 Electric Rate Case, the only two categories where the Company incurred costs were with regard to travel and expenses. The total amount incurred for the Miscellaneous Expense category was $26,908 and is subdivided as listed below:

Table MMA-D-5
Miscellaneous Expenses for 2017 Electric Rate Case

Miscellaneous Expenses	***Amount***
Travel and Expenses	$ 13,955
Regulatory Support	$ 12,953
Total	**$ 26,908**

Regulatory Support was for the incremental labor that the Company contracted to support the case by managing SharePoint site permissions, tracking Discovery requests and responses, and other administrative tasks necessary to manage the case. Travel and expenses were for out-of-state witnesses to attend meetings and discussions associated with the 2017 Electric Rate case as the Company prepared its filing.

C. <u>2016 Phase II Rate Case</u>

Q. PLEASE DISCUSS THE OUTSIDE LEGAL FEES THAT THE COMPANY INCURRED FOR THE COMPANY'S 2016 PHASE II RATE CASE.

A. The Company incurred $180,331 for outside legal costs for the firms Armstrong Teasdale and Moss & Barnett. These firms provided assistance in assembling testimony and attachments, advice on strategy, responding to discovery, and generally processing the case. The outside legal services were retained in order to supplement the Company's in-house legal staff's case load.

Q. PLEASE DISCUSS THE CONSULTANT COSTS THAT THE COMPANY INCURRED FOR THE COMPANY'S 2016 PHASE II RATE CASE.

A. The Company incurred $63,558 of consultant costs for The Brattle Group and DNV-GL. The Brattle Group provided consulting services to help the Company respond to intervenor critiques of the proposed residential demand charge based on a draft of the Brattle Group study of customer response to the RD-TDR (formerly RD-TOU) rate design. DNV-GL supported our measurement and verification study design process including experimental design and analysis, and control group considerations. They also conducted a power analysis to determine appropriate sample size targets required to sufficiently provide statistically significant results. DNV-GL's work was incorporated into the Company's RE-TOU & RD-TDR Study and Evaluation Plan, and they participated in all of the stakeholder meetings that occurred during the fall and winter of 2016 prior to the launch of the pricing plans.

Q. PLEASE DESCRIBE THE COSTS INCURRED TO MEET THE NOTICE REQUIREMENTS OF THE COMMISSION FOR THE 2016 PHASE II RATE CASE.

A. The Company incurred $41,425 for noticing the Phase II Rate Case. The bill onsert was $19,704, which is the cost associated with printing the notice on a customers' bills and mailing it to customers during their normal billing cycles. The newspaper notice was $17,997. This expense was to fulfill the requirement that we post the notice of our filing in a newspaper of general circulation for two consecutive Sundays. The cost for sending direct mail to Solar*Rewards customers was $3,724.

Q. WHAT WAS THE AMOUNT OF POSTAGE COSTS THAT THE COMPANY INCURRED FOR THE COMPANY'S 2016 PHASE II RATE CASE?

A. The Company incurred $54 of postage.

Q. PLEASE DISCUSS THE MISCELLANEOUS EXPENSES THAT THE COMPANY INCURRED FOR THE COMPANY'S LAST PHASE II RATE CASE.

A. Miscellaneous expenses cover communications with our employees regarding the rate case, market research, regulatory support, and travel and employee expenses for out-of-state witnesses. The total amount incurred for the Miscellaneous Expense category was $93,001 and is subdivided as listed below:

Table MMA-D-6
Miscellaneous Expenses for 2016 Phase II Electric Rate Case

Miscellaneous Expenses	*Amount*
Communications – Webinar	$ 2,175
Market Research	$ 39,740
Regulatory Support	$ $48,952
Miscellaneous	$ 2,134
Total	**$ 93,001**

The most significant subcategories in this cost category are Market Research and Regulatory Support. Market Research costs were for conducting Focus Groups with residential customers to gather their input on Grid Use Charges and the Company's long-term rate design. Regulatory Support was for the incremental labor that the Company contracted to support the case by managing SharePoint site permissions, tracking Discovery requests and responses, and other administrative tasks necessary to manage the case timely and accurately.

D. 2016 Depreciation Case

Q. PLEASE DISCUSS THE OUTSIDE LEGAL FEES THAT THE COMPANY INCURRED FOR THE COMPANY'S 2016 DEPRECIATION CASE.

A. The Company incurred $369,475 for outside legal costs for the firm Wilkinson Barker Knauer LLP. This firm provided assistance in assembling testimony and attachments, advice on strategy and legal issues, responding to discovery, and generally processing the case. The outside legal services were retained in order to supplement the Company's in-house legal staff's case load.

Q. PLEASE DISCUSS THE CONSULTANT COSTS THAT THE COMPANY INCURRED FOR THE COMPANY'S 2016 DEPRECIATION CASE.

A. The Company incurred $212,638 for consultant costs for a depreciation study conducted by Alliance Consulting Group ("Alliance"), and a Dismantling Study conducted by Burns & McDonnell. Alliance was primarily responsible for developing the electric and common utility plant depreciation rates using industry standard depreciation methods under the direction of the Company. These costs account for $152,711 of the total Consulting costs. Burns & McDonnell conducted the dismantling and decommissioning study that was used to develop the decommissioning costs used in the depreciation rates developed by Alliance. The 2016 decommissioning cost study was an update of the 2014 decommissioning cost study used in the 2014 Electric Rate Case, which resulted in some cost savings for the Company versus costs for a full blown study. Burns & McDonnell costs represent $59,927 of the total Consulting costs.

Q. PLEASE DISCUSS THE MISCELLANEOUS EXPENSES THAT THE COMPANY INCURRED FOR THE COMPANY'S 2016 DEPRECIATION STUDY.

A. The Company incurred $1,361 of miscellaneous expenses for travel and employee expenses for out-of-state witnesses.

E. <u>2016 Phase II Trial and Pilot</u>

Q. PLEASE LIST AND GENERALLY DESCRIBE THE MAJOR RATE CASE EXPENSE CATEGORIES YOU ARE PRESENTING FOR RECOVERY IN THIS RATE REVIEW FOR THE 2016 PHASE II TRIAL AND PILOT.

A. The major categories of rate case expenses included in my Attachment MMA-4 and Table MAM-D-3 below for the 2016 Phase II Trial and Pilot include the following areas:

<u>Marketing</u>: The costs required to drive awareness, educate, recruit, and retain customers into the Trial and Pilot.

<u>Staffing</u>**:** Funding to hire an incremental dedicated program manager and marketing assistant to manage the marketing and operational aspects to successfully run the Trial and Pilot.

<u>Measurement & Verification:</u> The expenses incurred to hire a third party consultant to advise on study design and conduct an impact analysis based on the billing data, as well as perform customer research.

<u>Billing and IT/Programming Costs</u>: Incremental costs required to build IT systems required to enroll and bill customers in the Trial and Pilot.

Table MMA-D-7
2016 Phase II Trial & Pilot Rate Case Expense Estimate

Type of Expense	Amount
Marketing	$ 1,950,097
Staffing	$ 559,939
Measurement & Verification	$ 1,087,793
Billing and IT/Programming Costs	$ 649,959
Total	**$ 4,247,788**

Q. HOW LONG WILL THE COMPANY RUN ITS RE-TOU TRIAL AND RD-TDR PILOT PROGRAMS?

A. The RE-TOU Trial will end in December 2019 and the RD-TDR Pilot will end in December 2021.

Q. PLEASE DISCUSS THE MARKETING COSTS THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THE 2016 PHASE II TRIAL AND PILOT.

A. The Company is using an appropriately robust marketing and education strategy to drive awareness about the two optional pricing plans, how they work, and the potential benefits to both the customer and the Company, and ultimately to enroll and retain customers in the Trial and Pilot. The strategy includes multiple tactics such as:

- Digital Web-page advertisements that display awareness and education messages for customers that have either been targeted due to: (1) online interests or to previous visits to relevant pages (like the pricing plan landing page); (2) segmentation and other demographic characteristics; and (3) interaction on social media (such as Facebook and Twitter);
- Direct mailing for recruitment, as well as retention;

- Bill onserts (formatted inside bill pages) and inserts (separate pages included in the bill);
- Email campaigns;
- Promotion in new service activation/ mover kits given to customers moving homes within the service territory;
- Paid social media advertising; and
- Earned media coverage obtained through press releases and media outreach.

To support many of these measures, the Company developed specific Trial and Pilot messaging, infographics, videos, customer call center scripts, webpages and social media content to illustrate the different pricing plans, and support various customer motivations (cost savings, carbon reductions, grid upgrades, etc.). Further, to continue to engage and support customers after their enrollment, the Company has created new website content, delivered door hang tags to notify customers of their meter installations, customer behaviors that can promote savings and new online customer reports on their billing usage. The Company has also mailed reminder tools, including clings that stick onto major household appliances as visual cues for how to be successful on the rates and the pricing periods of their relevant rates. The Company has also incurred costs associated with retention, engagement through emails, social media and additional website content (video, Frequently Asked Questions), and call center support. The total estimated marketing costs are $1,950,097.

Q. PLEASE DISCUSS THE INCREMENTAL STAFFING COSTS THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THE 2016 PHASE II TRIAL AND PILOT.

A. The Company hired a dedicated program manager and supporting marketing assistant to design and execute the overall customer experience and marketing strategy. Additionally, the dedicated program manager and supporting marketing assistant are responsible for the day to day operational management of the Trial and Pilot including enrollment, billing, metering, ongoing communications with pilot participants, data management and analysis, reporting of program metrics, working with internal teams involved in program implementation and engaging with regulatory stakeholders. The total cost estimated for staffing is $559,939.

Q. PLEASE DISCUSS THE MEASUREMENT AND VERIFICATION COSTS THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THE 2016 PHASE II TRIAL AND PILOT.

A. After a competitive solicitation and selection process, the Company hired Navigant Consulting to perform a third-party M&V study for the Trial and Pilot. Navigant is responsible for: (1) advising the Company and stakeholders on study design; (2) verifying the experimental design to reduce bias and ensure statistical confidence and precision can be achieved; (3) managing the solar control group matching process; (4) performing customer research throughout the Trial and Pilot including surveys and interviews; (5) analyzing the meter and billing data; and (6) ultimately reporting on the impact of the Trial and Pilot on driving load reduction across the sample segments, as well as a whole. Navigant will provide annual preliminary impact reports, annual presentations to regulatory stakeholders, summaries of the ongoing customer research, as well as final reports. The scope of work describing these activities in more detail is included in the Company's confidential workpapers. The total contracted value of these services is $1,087,793.

Q. PLEASE DISCUSS THE BILLING AND IT/PROGRAMMING COSTS THAT THE COMPANY IS PROJECTING TO INCUR AS PART OF THE 2016 PHASE II TRIAL AND PILOT.

A. In order to accommodate the participants on the new rates, it was necessary for the Company to build a new enrollment system as well as make significant changes and additions to the billing system to account for the new tariffs. Due to the complexity of the rate design and to ensure a positive customer enrollment experience, it was also necessary to develop an unprecedented integration of multiple internal IT systems, including: (1) the Company's My Account platform so customers could enroll online; (2) the call center system so customers could call to enroll; (3) the billing system so the process for billing changes would be seamless and to facilitate meter order creation so the meter shop could exchange the customer's meter with a bridge meter; and (4) Salesforce to serve as the program system of record and to allow the Company to efficiently conduct marketing campaigns, as well as a manual Excel macro workbook to process the necessary random assignment of control group participants. Additionally, the

Company developed capabilities in My Account to present customers with historical visualization of their energy usage broken into the different time periods in annual, monthly, and daily views. The total cost treated as rate case expense for this undertaking is estimated to be $649,959,[22] which is in addition to the $330,000 already incurred and approved for recovery through the S&F charge.

Q. HOW WILL THESE 2016 PHASE II TRIAL AND PILOT COSTS INFORM THE COMPANY'S LONG-TERM RATE DESIGN?

A. The central purpose of the Trial and Pilot is to test how customers respond to time varying rates, in terms of behavior change (load reduction and bill savings), customer experiences and the general acceptance and understanding of new rate structures. Findings from the Trial and Pilot will inform long term rate design not only in terms of the determining the optimal pricing differentials and periods, but also in understanding customer preferences, attitudes, education requirements, engagement techniques and acceptance of different pricing plans, as well as assessing how these different rates impact different population segments with varying household characteristics with different end use technologies. This is particularly important as the Company plans to roll out a TOU rate concurrent with AMI deployment on an opt-out basis. All the costs incurred during the course of the Trial and Pilot were necessary to ensure a

[22] Per the Settlement Agreement from Public Service's Phase II electric rate case in in Proceeding No. 16AL-0048E: any additional programming and billing costs for the RE-TOU service and RD-TDR Trial and Pilot above the $330,000 of one-time programming and billing costs shall be treated as rate case expenses eligible for deferred accounting and recovery in a subsequent proceeding. The $649,959 reflects only the costs eligible for deferred accounting above the $330,000.

productive study with useful, robust, statistically significant results with limited bias, as well as learnings and tools that could potentially be applied towards future roll out of AMI technology to all our Colorado customers.

Q. HOW WILL INCURRING THESE COSTS HELP ENSURE A SUCCESSFUL IMPLEMENTATION OF THE LONG-TERM RATE DESIGN?

A. While all of the incurred costs described are necessary to inform a successful program and therefore deliver valuable information to inform long-term rate design, several categories will be particularly impactful towards ensuring successful implementation of the Advanced Grid Intelligence and Security ("AGIS") AMI roll out and concurrent TOU rate deployment to all our Colorado customers. To start, the Marketing and Staffing costs invested now will yield benefits and best practices for how to raise awareness. These expenditures will also provide valuable information and experience regarding how to engage and educate customers on the value of more granular data and time varying rates including optimal messaging, tactics, and awareness campaigns. Internal IT development of enrollment, billing, metering, and customer database system architectures can be directly leveraged for use for when the majority of our customers will be billed and metered on a TOU rate. Metering practices developed as part of the Trial and Pilot implementation can be utilized and built upon to prepare for the installation of AMI meters to all our Colorado customers.

Q. IS THE COMPANY PROVIDING SUPPORTING DOCUMENTATION FOR THE ACTUAL RATE CASE EXPENSES THE COMPANY HAS INCURRED FOR RECOVERY IN THIS CASE?

A. Yes. The Company is providing supporting documentation for actual rate case expenses as confidential workpapers in this case.

Q. DO YOU BELIEVE THAT THE COSTS DESCRIBED ABOVE ARE REASONABLE?

A. Yes. We have worked diligently to find ways to reduce these rate case expenses, such as the alternative form of notice ("AFN") and bidding out our ROE witness and M&V activities. Where we do not have vendor contracts to aid in cost estimations, we used rate case expenses incurred in previous rate cases that were either settled or litigated over a long period and involved extensive discovery.

V. REQUEST TO DISCONTINUE EAFPM

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR DIRECT TESTIMONY AS IT RELATES TO THE EQUIVALENT AVAILABILITY FACTOR PERFORMANCE MECHANISM.

A. In this section of my Direct Testimony, I address the basis for the Company's proposal to discontinue the EAFPM.

Q. STARTING WITH THE BASICS, WHAT IS THE EAFPM?

A. The EAFPM is a performance metric that provides incentives and penalties for Public Service in managing its generation fleet. The EAFPM is measured by comparing the weighted average of the Equivalent Availability Factor of the core of Public Service's coal and combined cycle gas generating units against certain historical thresholds. If Public Service's weighted average EAF is at or below the lower threshold, the Company is assessed a penalty of $3 million. On the other hand, if Public Service's weighted average EAF is at or above the upper threshold, the Company receives a $3 million incentive. To the extent Public Service's weighted average EAF is within the lower and upper threshold amounts – what I describe as the EAFPM "dead band" – then there is no impact to the Company.

Q. WHAT WAS THE PURPOSE OF THE EAFPM?

A. Public Service proposed the EAFPM as part of the Company's 2014 Rate Case to address stakeholder concerns regarding the impact of a relatively flat O&M budget on the Company's operation of its generation fleet. The purpose of the

EAFPM was to demonstrate that Public Service could maintain the availability of its core generation fleet consistent with its past results while keeping its O&M budget relatively flat.

Q. WHAT IS EAF?

A. EAF is a commonly used industry metric that measures all the available hours a unit can operate during a defined period. The EAF metric captures planned and unplanned outages as well as unit de-rates. EAF is a metric calculated from performance and event data reported to NERC and tracked within the Generating Availability Data System ("GADS"). The GADS data system contains the event and performance data of all generating units in the nation that are 20 MW or greater.

Because EAF captures all events that impact available hours of a unit during a given period, including any planned or unplanned events, EAF is a strict measure of plant availability. Further, because EAF measures availability, it is a sound metric to measure the performance of both baseload coal units, intermediate combined cycle units, and peaking combustion turbines in a single metric.

Q. WHAT ARE THE PARAMETERS OF THE EAFPM?

A. The parameters of the EAFPM are set forth in the Settlement Agreement from the 2014 Electric Rate Case, which was approved by the Commission in Decision No. C15-0292. The Settlement Agreement addressed: (1) the duration of the EAFPM; (2) the units and data utilized for the EAFPM; and (3) the EAFPM incentive/penalty thresholds and the dead bands for 2015, 2016, and 2017, respectively.

The EAFPM commenced in 2015 and expired at the end of 2017. The Settlement Agreement provided that the EAFPM will be reexamined in the 2017 Electric Rate Case, and given the dismissal of that case we are addressing the future of the EAFPM in my Direct Testimony here in this rate review. The Settlement Agreement also required Public Service to present a proposal to continue, modify, replace, or discontinue the EAFPM going forward. As I noted above, Public Service recommends that the EAFPM be discontinued as it has served its purpose.

Q. BEFORE PROVIDING MORE DETAIL ABOUT THE BASIS FOR THE COMPANY'S DISCONTINUANCE PROPOSAL, PLEASE PROVIDE DETAIL REGARDING WHICH PUBLIC SERVICE GENERATING UNITS ARE SUBJECT TO THE EAFPM.

A. Pursuant to the Settlement Agreement, the actual capacity weighted average EAF for the following generating units was measured: Cherokee 4, 5, 6, and 7; Comanche 1, 2, and 3; Hayden 1 and 2; Pawnee; Fort St. Vrain 1, 2, 3, and 4;

and Rocky Mountain Energy Center 1, 2, and 3. The actual capacity weighted average EAF calculation was made using EAF data as reported to NERC pursuant to GADS data reporting instructions and IEEE 762 metric calculations. Public Service was also permitted to adjust its EAF calculation for events that are classified as Outside of Management Control ("OMC") using NERC criteria and for outage events that are specifically attributable to an order by a state or federal regulatory agency or law.

The terms of the Settlement Agreement also provided that the EAFPM dead band for 2015 was between 83.79 percent and 86.19 percent. In addition, the Settlement Agreement established the 2016 and 2017 EAFPM dead bands between 84.49 percent and 86.57 percent.

Q. HOW HAS PUBLIC SERVICE PERFORMED UNDER THE EAFPM?

A. Public Service operated within the EAFPM dead band in 2015 and 2016, demonstrating that Public Service is able to achieve its goal of maintaining its plant availability under flat O&M conditions. In 2015, Public Service's weighted average EAF was 84.32 percent, which was within the parameters of the EAFPM dead band set by the Settlement Agreement for 2015 of 83.79 percent to 86.19 percent. In 2016, Public Service's weighted average EAF was 86.09 percent, which was within the parameters of the EAFPM dead band set by the Settlement Agreement for 2016 of 84.49 percent to 86.57 percent. Finally, in 2017 Public Service's weighted average EAF was 88.08 percent, which exceeded the upper threshold of the dead band (86.57 percent). Therefore, the Company received a $3 million incentive for its performance in the 2017 year under the EAFPM.

Q. WHAT DO YOU CONCLUDE FROM PUBLIC SERVICE'S WEIGHTED AVERAGE EAF IN 2015, 2016, AND 2017?

A. I conclude Public Service has managed its baseload coal and intermediate combined-cycle gas fleet in a prudent manner and has increased the fleet's availability for dispatch on behalf of our customers consistent with the expectations of the Company and all parties to the Settlement Agreement. I would also note that Public Service was able to achieve its EAF performance with relatively flat O&M year-over-year. Company witness Mr. Kyle I. Williams addresses the Company's O&M expense in more detail in his Direct Testimony.

Q. IN YOUR OPINION, DID THE EAFPM SERVE ITS FUNCTION?

A. Yes. The EAFPM demonstrated that Public Service can maintain service quality from its generating fleet while aggressively controlling O&M spending. Because it has served its function, I recommend that the Commission discontinue the EAFPM and we have brought forward revised tariff sheets reflecting this discontinuance as part of our direct case.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. Public Service has demonstrated consistent fleet performance over a period of years when O&M budgets have been flat, consistent with the purpose of the EAFPM. Therefore, the Company believes there is no need to continue with the program.

Q. DO YOU EXPECT PUBLIC SERVICE'S EAF PERFORMANCE TO ERODE WITHOUT THE INCENTIVE AND PENALTY PROVIDED BY THE EAFPM?

A. No. Public Service's ultimate focus has been and continues to be on providing reliable service to customers at reasonable cost, which is achieved through maintaining plant availability in a safe and reliable manner. While the EAFPM provided an additional incentive for Public Service to work towards a very high EAF performance, Public Service will continue to operate its generating fleet in a prudent manner without it. Further, the Commission retains oversight of Public Service's fleet performance through the ECA review process.

VI. CLASSIFICATION OF AMI METER COSTS

Q. DID THE AGIS SETTLEMENT REQUIRE THE COMPANY TO ADDRESS ANY ISSUES IN THIS PROCEEDING?

A. Yes in Proceeding No. 16A-0588E, the Commission approved the Unopposed Comprehensive Settlement Agreement ("AGIS CPCN Settlement"), which required the Company to present a proposal for the costs classification of AMI meters in its next rate case.[23] Specifically, Section III.E.4 on page 18 of the AGIS CPCN Settlement included the following:

> AMI meters are utilized for more than measurement of a customer's consumption and for billing purposes as discussed in the Background section above. Therefore, it is reasonable that some portion of the meter cost not be classified as a specific customer cost. In its next Phase I and Phase II rate proceedings, the Company shall present a proposal for assigning the portions of the AMI meter costs to the functions that cause those costs. The Settling Parties expressly reserve the right to raise any arguments concerning all elements of the proper allocation of costs in future rate cases.

Q. ARE THERE ANY AMI METER COSTS INCLUDED IN THE REVENUE REQUIREMENTS PRESENTED IN THIS CASE?

A. No. The 2019 capital reach forward does include the cost of IVVO implementation, but the meters used for IVVO are separate and distinctly different than the AMI meters that will be deployed after 2019.

Even though there are no AMI costs included in this case and even though cost classification in not an issue typically addressed in a Phase I rate review

[23] *See* Decision No. C17-0556, mail date July 25, 2017, Proceeding No. 16A-0588E.

proceeding, the Company is earnest in its desire to conform to the requirements of the AGIS CPCN Settlement.

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING THE CLASSIFICATION OF AMI METER COSTS?

A. The Company is proposing to classify 17 percent of AMI meter costs as demand-related costs. Those costs will be then allocated to customer classes based on peak demand measurements as is typically done with distribution related costs in Phase II rate review proceedings. This classification and cost allocation is expected produce lower monthly service and facilities charges in the future as compared to what these charges would be in the absence of AMI.

Q. WHAT METHOD DID YOU USE TO CLASSIFY THE INCREMENTAL AMI COSTS?

A. I examined the additional benefits that AMI meters bring to the system using the AMI meter cost-benefit analysis relied on in Proceeding No. 16A-0588E. The AMI meter cost-benefit analysis was presented in the AGIS proceeding to compare the costs with the quantifiable benefits of AMI, as well as to provide a more detailed breakdown of individual cost and benefits assumptions. A few of the benefits, such as reduced meter reading and field service costs, were classified as customer-related benefits. But the majority were classified as demand-related benefits. Because very few of the costs were classified as energy-related (about 6 percent), I included them as demand-related in the analysis for simplicity. The split for AMI benefits was about 73 percent demand-related and 27 percent customer-related.

Q. HOW DID YOU USE THAT BREAKDOWN TO DETERMINE THE APPROPRIATE CLASSIFICATION OF AMI METER COSTS?

A. I multiplied the incremental cost of an installed AMI meter (23 percent, as explained above) by the percentage contribution of demand-related benefits (73 percent) to total AMI benefits to derive the percentage of AMI meter costs classified as demand-related. This percentage is approximately 17 percent.

This detailed calculation is included as Attachment MMA-5.

Q. HOW WILL CLASSIFYING 17 PERCENT OF AMI COSTS AS DEMAND-RELATED IMPACT FUTURE RATE REVIEW PROCEEDINGS?

A. In a future Phase II proceeding that includes the cost of AMI meters, 17 percent of those costs will included as secondary distribution costs. Secondary distribution costs are allocated to customer classes based on the sum of the peak demands of all the customers in each rate class. Those allocated costs are then included in the distribution demand charges for C&I customers or the energy charges for Residential and Small Commercial customers.

Q. HOW DOES THE COMPANY’S PROPOSAL IMPACT THIS PROCEEDING?

A. Because no AMI meter costs have been included in this proceeding, the proposal to classify 17 percent of AMI costs as demand-related does not affect the Company’s cost of service and revenue requirement in this proceeding. .

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSAL FOR THE CLASSIFICATION OF AMI METER COSTS?

A. I have presented our proposal in this case to ensure that the Company is in compliance with the AGIS CPCN Settlement. However, I recommend that the Commission take no action regarding this proposal at this time and instead postpone action until a subsequent Phase II proceeding that includes the cost of AMI meters. By postponing the decision on the classification of AMI meter costs, the Commission can ensure that it has actual AMI meter cost and class cost allocation analysis that will be critical in evaluating the impact of this proposal.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend the Commission approve for inclusion in base rates the 2018 HTY revenue requirements associated with the CACJA Rider, the TCA, and the Rush Creek Wind Project, for the amounts set forth in my Direct Testimony and supported further by Ms. Blair, recognizing that these changes do not increase the Company's overall revenue, but merely shift cost recovery from rider recovery to base rate recovery. I recommend approval of all other changes to our electric tariff described in Advice No. 1797 – Electric, and included as Attachments MMA-1 and MMA-2 to my Direct Testimony. Additionally, I recommend recovery of $7,669,077 in total rate case expenses, inclusive of $1,470,241 in rate case expenses specifically related to this proceeding, amortized over 36 months. I recommend discontinuance of the EAFPM. Finally, I recommend that the Commission postpone any decision on the Company's proposal of classification of AMI Meter Costs, which was presented consistent with the AGIS CPCN Settlement but is more appropriately addressed in a Phase II rate design proceeding.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Michelle M. Applegate

Ms. Applegate graduated from the Colorado School of Mines with a degree in Metallurgical and Material Engineering and minors in Public Affairs and Economics. She began her employment with Xcel Energy Services, Inc. in 2003. Since then she has held various positions in engineering, operations and regulatory affairs within the electric and gas utility industry.

From 2003 to 2008, Ms. Applegate worked as a Production Engineer in natural gas, electric and hydro-electric generating facilities for Xcel Energy Service, Inc. In that position, she was responsible analyzing failures and making recommendations as to the operating procedures of the generating facilities.

In 2008, Ms. Applegate was employed as a Case Specialist in the Regulatory and Government Affairs Department for Public Service Company of Colorado, where she was responsible for developing support and testimony and managing cases related to the company's renewable energy standards and policies.

In 2010, Ms. Applegate began employment with Summit Utilities, Inc. as the Manager of Regulatory Affairs. Her responsibilities included oversight of the multi-jurisdictional department and maintaining compliance with state and federal regulatory requirements, as well as financial and environmental state statutes in multiple rate areas. In January of 2013, she was promoted to Director of Regulatory Affairs.

Ms. Applegate accepted the role of Senior Director of Engineering and Technical Services with SourceGas, LLC in April 2014. In this role she provided leadership and oversight to the Engineering and Technical Services Organization within SourceGas Operations. Her responsibilities included the areas of Engineering, Pipeline Integrity, GIS and Asset Records, Measurement, Environmental Health and Safety, Technical Training, Codes and Standards, and Construction Project Management departments.

Ms. Applegate joined Black Hills Energy in February 2016 as the Director, Technical Services. In this role she continued to support the technical functions that support field operations including Engineering, Pipeline Integrity, Compliance, Measurement and GIS functions. In June 2017 she was appointed to the role of Director, Asset Planning and Data Management.

Ms. Applegate joined Xcel Energy in June 2018 as the Director, Regulatory Administration. She is responsible for providing leadership, direction, and technical expertise related to regulatory processes and functions for Public Service Company of Colorado.

Ms. Applegate has testified before the Colorado Public Utilities Commission, the Missouri Public Service Commission and the Maine Public Utilities Commission on various regulatory, rate, certificate, and tariff issues.

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 MICHELLE M. APPLEGATE ON BEHALF OF PUBLIC SERVICE COMPANY OF COLORADO

I, Michelle M. Applegate, 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 14 day of May, 2019.

____

Michelle M. Applegate
Director, Regulatory Administration

Subscribed and sworn to before me this 14 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