BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

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<u>SETTLEMENT AGREEMENT</u>

January 23, 2015

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**BEFORE THE PUBLIC UTILITIES COMMISSION
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RE: IN THE MATTER OF ADVICE LETTER NO. 1672-ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 7-ELECTRIC TARIFF TO IMPLEMENT A GENERAL RATE SCHEDULE ADJUSTMENT AND OTHER OTHER CHANGES EFFECTIVE JULY 18, 2014.	)	**PROCEEDING NO. 14AL-0660E**
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SETTLEMENT AGREEMENT

Introduction

Public Service Company of Colorado ("Public Service" or the "Company"), the Staff of the Colorado Public Utilities Commission ("Staff"), the Colorado Office of Consumer Counsel ("OCC"), Colorado Energy Consumers ("CEC"), Colorado Healthcare Electric Coordinating Council ("CHECC"), Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel (collectively "Climax/Evraz"), Energy Outreach Colorado ("EOC"), the Federal Executive Agencies ("FEA"), the

Kroger Co. ("Kroger"), and Wal-Mart Stores, Inc. and Sam's West, Inc. ("Wal-Mart") (collectively, the "Settling Parties") hereby enter into this Settlement Agreement.[1]

This Settlement Agreement is a comprehensive uncontested settlement, which proposes a resolution for all issues that have been raised or could have been raised in this consolidated proceeding.

Background

On June 17, 2014, Public Service filed Advice Letter No. 1672-Electric, together with the supporting direct testimony and exhibits of nineteen witnesses. In this filing, Public Service sought to increase its base rate revenues by $157,617,251, which reflects a shift of $19,947,918 in costs that Public Service is presently recovering through its Transmission Cost Adjustment ("TCA") to base rates, resulting in a net requested increase of $137,669,333. Public Service also requested authorization to recover costs that it is incurring to implement its compliance plan under the Clean Air-Clean Jobs Act ("CACJA") through a new rider. Public Service sought to support its requested rate increase through a January 1, 2015 to December 31, 2015 test year, which included forecasted capital costs but historical (2013) operating and maintenance costs with limited adjustments. Public Service included with its filing a 2013 historical test year with adjustments ("HTY"). Public Service in its filing additionally requested authorization to implement a decoupling mechanism and a generation performance benchmarking plan – referred to as the Equivalent Availability Factor Performance

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[1] The intervenors in this proceeding who have not joined as parties to the Settlement Agreement have had opportunity to review it and have indicated that they will take the following positions: City and County of Denver – will not oppose the Settlement Agreement; Southwest Energy Efficiency Partnership – no position; The Alliance for Solar Choice – no position; the City of Boulder – no position; Clean Energy Action – no position; Western Resource Advocates – will neither oppose nor support. Accordingly, the Settling Parties believe the Settlement Agreement is unopposed.

Mechanism ("EAFPM") – that could potentially provide Public Service with a $3 million incentive payment or penalty based on the performance of specified generating units. By Decision No. C14-0807 issued in Proceeding No. 14AL-0660E, the Commission suspended the tariff sheets filed with Advice Letter No. 1672-Electric for 120 days, or until November 15, 2014, and set the matter for hearing *en banc*.

On June 23, 2014, Public Service filed an application seeking the Commission's authorization to decommission and dismantle its Arapahoe Generating Station and to remediate and restore the plant site at an estimated cost of $34.8 million. The Commission docketed this application in Proceeding No. 14A-0680E. Concurrently with the filing of the application, Public Service requested that Proceeding Nos. 14AL-0660E and 14AL-0680E be consolidated. The Commission granted that request in Decision No. C14-1043.

In Decision No. C14-1043, the Commission also further suspended Public Service's tariff sheets for an additional 90 days, or until February 13, 2015. Subsequently, the Commission accepted a procedural schedule that would have resulted in a Commission decision being issued after that date. However, in Decision No. C14-1130, the Commission adopted a refund mechanism that would allow the Company to implement its proposed rates on February 13, 2015, subject to a refund condition in the event that a final order addressing Public Service's rate request is not decided before that date.

As directed by the Commission in Decision No. C14-1130, Public Service on September 26, 2014, filed supplemental direct testimony providing more information regarding its generation performance benchmarking plan which included the Commission Staff's report prepared in Proceeding No. 13I-0215E as an exhibit.

In Decision No. C14-1331, the Commission dismissed Public Service's proposed decoupling mechanism from this proceeding, finding that it would be more appropriately addressed in a standalone proceeding.

On November 7, 2014, the following parties submitted answer testimony: Staff, the OCC, CEC, CHECC, Climax/Evraz, FEA, and Wal-Mart. Each of these parties recommended reductions to Public Service's proposed increase to base rates. Staff, OCC and other intervenors took a variety of positions in regards to the appropriate test year, the treatment of Public Service's request for a CACJA Rider, and a number of other proposed adjustments.

In its rebuttal case submitted on December 17, 2014, Public Service adjusted its revenue requirement for its 2015 test year to $127,137,403 (inclusive of the roll in of TCA costs). This adjustment was made for three purposes: to correct errors; to recognize certain positions made by the parties in answer testimony; and to update for more recent information. Among other things, in Public Service's rebuttal testimony, Public Service proposed that all costs for CACJA projects be recovered through the CACJA rider from 2015 through 2017 and subsequent true ups. Public Service also provided a revised 2013 cost of service study, which as explained below, became the basis for developing the settlement rates reflected in this agreement.

On December 17, 2014, CEC and CHECC also submitted cross-answer testimony. Those testimonies contended, among other things, that Public Service was not entitled to a CACJA Rider.

Throughout this proceeding, the Settling Parties discussed the possibility of resolving this case through a settlement. On January 14, 2015, the due date for settlement agreements as set out in the procedural order for this proceeding established by the Commission, the OCC on behalf of all of the Settling Parties submitted a filing to the Commission noting that discussions were still ongoing and that the Settling Parties believed a settlement could be reached. The Settling Parties subsequently were able to agree to a settlement in principle on January 16, 2015, and on that same date, Public Service on behalf of the Settling Parties filed a notice advising the Commission of this fact. The Commission suspended the schedule in an order dated January 21, 2015.

Settlement

I. Commitments Relating to Currently Proposed Rates.

A. Effectiveness.

The Settling Parties acknowledge that the effect of this Settlement Agreement is to modify the tariff sheets that Public Service filed on June 17, 2014 with the Commission through Advice Letter No. 1672-Electric. Pursuant to the refund condition adopted by the Commission in Decision No. C14-1130, the tariff sheets filed with Advice Letter No. 1672-Electric are scheduled to become effective subject to refund on February 13, 2015. The Settling Parties agree that, in lieu of the rates and other tariff changes originally proposed by the Company as set forth in the tariff sheets filed with Letter No. 1672-Electric, the Company should implement on February 13, 2015, the settlement rates and tariff sheets in substantially the same form as the pro forma tariff sheets set forth in Attachment L ("Clean Settlement Tariff Sheets")[2]. To that end, on or before January 23, 2015, the Settling Parties shall file with the Commission a joint motion requesting a Commission decision authorizing Public Service to place the Settlement Tariff Sheets into effect on February 13, 2015, subject to the same refund condition approved by the Commission in Decision No. C14-1130-I in the event the ultimate rates put into effect are lower than those put into effect on February 13, 2015 and a surcharge condition in the event the ultimate rates put into effect are higher than those put into effect on February 13, 2015. In the event that the Commission issues a decision approving this Settlement Agreement by February 10, 2015, or grants the Settling Parties' Joint Motion to place the Settlement Rates into Effect prior to that date, the rates set forth in this Settlement Agreement will be placed into effect on that date. If the Commission approves the Settlement Agreement at a later date and denies the Joint Motion to Place the Settlement Rates into Effect on February 13, 2015, Public Service shall place the filed rates into effect on February 13, 2015 in accordance with Decision No. C14-1130-I, subject to refund.

The agreed-to rates will be subject to an Earnings Test and Stay-Out provision, as described below, which are intended to result in the settlement rates, if approved, remaining in effect until replaced by new base rates resulting from Public Service's next base rate change filing in 2017 for rates expected to go into effect no earlier than January 1, 2018 ("2017 Rate Case").

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[2] Red-lined tariff sheets are provided for each of the tariffs that are changing from the currently effective tariffs as Attachments C, D, G, H, I, J and K as identified below.

B. Overall Customer Impact.

As indicated in Attachment A, the net impact to customers of the changes to base rates, implementation of the new CACJA rider, and implementation of a reduced amount for the existing TCA rider mechanism as the Company has proposed in this proceeding includes a base rate decrease of $39,418,515, an initial CACJA rider of $96,968,401, and a revised TCA of $15,610,346, resulting in a 2015 anticipated net customer impact of $41,500,000 subject to CACJA and TCA rider true-ups. Attachment B provides a breakdown of the overall customer impacts of the proposed revenue requirement changes and the changes in the CACJA rider and the TCA that would result from the approval of the Settlement Agreement. The impact on a typical residential customer in 2015 is an overall increase of $0.96 per month or 1.3%, inclusive of base rates, CACJA rider, and the TCA. Attachment B reflects the customer impacts for the five major customer classes of this Settlement Agreement for 2015, and anticipated impacts for those same classes in 2016 and 2017.

C. Adjustment to Proposed Revenue Requirement and Resulting Base Rate Decrease.

The following adjustments have led to a reduction in the base rate revenue requirement proposed by Public Service, and will result in a decrease in base rates.

1. Test Year.

As the starting point for developing the settlement rates included in this Settlement Agreement, the Settling Parties agreed to use the 2013 Historical Test Year ("2013 HTY") presented by Ms. Deborah Blair as Second Revised Attachment No. DAB-3 to her Rebuttal Testimony which uses a year-end rate base. The 2013 HTY reflects the impacts of Bonus Tax Depreciation.[3] As shown in Attachment A, the 2013 HTY, as filed by the Company and used in developing settlement rates, would have resulted in a base rate increase of $4,540,070. As shown on Attachment A, after the adjustments identified below, the resulting net base rate revenue requirement is negative $39,418,515, thereby resulting in a base rate decrease.[4]

2. Authorized Return on Equity ("ROE").

The Settling Parties agree that the authorized ROE should be set at 9.83%. As shown in Attachment A, use of this ROE will result in an adjustment reducing the 2013 HTY revenue requirement by $21,714,753.

3. Capital Structure.

For purposes of this Settlement Agreement, the Settling Parties agree to the development of base rates using Public Service's proposed capital structure – 56% equity/44% debt. This agreement is predicated on Public Service's commitment to manage the equity component of its capital structure as described below.

4. Cost of Debt.

As reflected in Attachment A, the Settling Parties agree to a cost of debt as of December 31, 2013 of 4.67% calculated using the par value method as shown on Sheet 1 of Attachment No. MPS-7 to the Direct Testimony and Attachments of Mary P. Schell.

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[3] The bonus tax depreciation affecting the 2013 HTY is based on income tax laws existing before the enactment of the Tax Increase Prevention Act of 2014, H.R. 5771, 113th Cong. (2014)(enacted), which extended bonus depreciation to certain assets placed in service during 2014. The 2013 HTY revenue requirement is not impacted by this new tax law.

[4] The parties acknowledge that OCC's agreement to use a year-end rate base is due to the facts and circumstances surrounding Public Service's filing in this proceeding and Public Service's agreement to a Stay-Out provision described below, which would result in the settlement rates, if approved, remaining in effect until replaced by new base rates expected to go into effect no earlier than January 1, 2018.

This is an adjustment to the 2013 HTY that will increase the Company's revenue requirement by $3,156.

5. Resulting Weighted Average Cost of Capital ("WACC").

When applying the various principles outlined above for ROE, capital structure and cost of debt, the resulting WACC is 7.55% as of January 1, 2015.

6. Pension.

(i) Pre-paid pension asset balance as of December 31, 2014 ("Legacy Pre-Paid Pension Asset").

The Settling Parties agree that a fifteen (15)-year amortization of the prepaid pension asset balance as of December 31, 2014 ("Legacy Pre-Paid Pension Asset") will be established, and further agree that, for purposes of developing settlement rates, this balance is $139,137,447 (inclusive of Accumulated Deferred Income Tax, or "ADIT"). The annual amortization to be included in the revenue requirement will be $9,275,830.

For purposes of the Earnings Test described below and in future rate cases, as part of this Settlement Agreement, the Company agrees that it will include the remaining, unamortized Legacy Pre-Paid Pension Asset balance in rate base. The Settling Parties agree that from January 1, 2015 until rates become effective from the 2017 Rate Case, the Legacy Pre-Paid Pension Asset will earn a rate of return equal to the Company's Cost of Debt as used in this Settlement Agreement – i.e., 4.67% as set forth above. In the 2017 Rate Case and afterwards, Public Service and other Settling Parties are free to argue for a different going-forward rate of return (including none) for the remaining balance on the Legacy Pre-Paid Pension Asset.

(ii) Pre-paid pension asset balance accumulated on and after January 1, 2015 ("New Pre-Paid Pension Asset").

The Settling Parties agree that Public Service should be permitted to record prudently incurred amounts for pre-paid pension assets or liabilities accumulating on or after January 1, 2015. The balance shall be treated as a regulatory asset or liability and shall be called the New Pre-Paid Pension Asset. Until such time as new rates are put into effect following the 2017 Rate Case, Public Service shall not earn a return or otherwise apply carrying charges on the New Pre-Paid Pension Asset balance.

The Company will make a filing to recover those amounts accumulated in the New Pre-Paid Pension Asset at the earlier of either (a) a future rate case or (b) in a stand-alone case filed within a reasonable time (no more than 90 days) after the amount in the New Pre-Paid Pension Asset becomes more than $50,000,000. In the stand-alone case the Company may request a new or modified GRSA. In its filing, the Company will propose the manner in which such amounts may be recovered and the explanation for why the New Pre-Paid Pension Asset was accumulated. In a proceeding addressing such filing, parties will be free to challenge the recovery of these amounts and the manner in which those amounts may be recovered to the extent the Company incurred those amounts imprudently or the recovery as proposed by the Company would be unjust or unreasonable. The designation of such amounts as a regulatory asset will not be used to preclude arguments that the amounts should not be recovered, or that the carrying costs should be modified or eliminated. Nothing in this Settlement Agreement, including the designation of the balance as a regulatory asset or liability, shall limit any Settling Party's ability to advocate for any position they deem appropriate regarding the New Pre-Paid Pension balance in the 2017 Rate Case including but not limited to whether the New Pre-Paid Pension Asset was prudently incurred, whether recovery of the New Pre-Paid Pension Asset would be just and reasonable, the manner in which the New Pre-Paid Pension Asset may be recovered in rates (for example, recovered immediately in full or included in the ongoing amortization of the Legacy Pre-Paid Pension Asset), and the appropriate rate of return for the New Pre-Paid Pension Asset, if any. Further, nothing in this Settlement Agreement shall limit the Commission's discretion in the 2017 Rate Case to determine the appropriate ratemaking treatment for the New Pre-Paid Pension Asset.

(iii) Pension Expense Tracking

The Settling Parties agree that a pre-paid pension expense baseline shall be set as follows:

- Non-Qualified: $883,950
- Qualified: $21,086,171

On an annual basis, amounts incurred above or below the baseline established here will be deferred in an accounting regulatory asset for inclusion in the 2017 Rate Case under the same limitations, conditions, and reservation of rights as described in Section *I*.C.6(ii) above.

(iv) Pre-paid pension reporting requirements.

Pension reporting requirements are as set out in Attachment F.

7. Property Tax.

The Settling Parties agree that the base rates that will take effect as a result of this Settlement Agreement total $137,334,694 (electric retail) of property tax expense.

This amount includes the recovery of $109,506,702, which is the level of allocated actual property tax expense incurred by the Company in 2013 and $27,827,992 which is the 2015 amortization of property tax expenses deferred during 2012 through 2014 that was calculated in accordance with the Settlement Agreement entered into in Proceeding No. 11AL-947E. The Settling Parties agree that Public Service shall continue to amortize property taxes deferred from the 2012 through 2014 period.

On a going forward basis, the Settling Parties agree that Public Service should be permitted to defer in a regulatory asset any difference in allocated property tax expense and property tax amortization from the amount actually incurred, as determined on an annual basis, beginning with calendar year 2015 until the rates approved in the 2017 Rate Case go into effect – which will be no earlier than January 1, 2018. In the 2017 Rate Case, the Company will propose that any such additional deferred tax amounts will be amortized over the same number of annual periods they were accrued.

8. Other Revenue Requirement Adjustments.

Through this Settlement Agreement, the Settling Parties have reached a series of compromises regarding numerous other issues relating to the Company's cost of service, including, but not limited, to the following: test year, rate case expenses, Ponnequin Wind Farm, Metro Ash Facility, Oil and Gas Royalty Revenues, Western Electricity Coordinating Council Fees, aviation expenses, generation overhaul expenses, legal expenses, employee compensation, and the Annual Incentive Pay ("AIP") impacts on pension expense for payments above target AIP. As a further example, through this Settlement Agreement, Public Service is foregoing its request to implement its proposed changes to its depreciation rates and amortization expense for electric and common utility plant in this proceeding and in light of the agreements discussed below will address depreciation and amortization issues, including cost of removal and net salvage, in a separate proceeding. Without agreeing to any specific adjustments or assigning any values for these issues on an individual basis in the development of settled rates, but to reflect the compromises the Settling Parties have reached on all of these issues through this Settlement Agreement, the Settling Parties have agreed that the 2013 HTY revenue requirement should be reduced by $31,735,761.

D. Rider Recovery.

The Settling Parties agree in resolution of this case to allow the implementation of the CACJA rider[5] and modify the existing TCA on the terms outlined below.

1. CACJA Rider.

The Settling Parties agree that a CACJA rider will be put into effect starting with calendar year 2015. Attachment C to this Settlement Agreement reflects the CACJA rider agreed to by the Settling Parties and details how the CACJA rider will operate beginning in 2015. Attachment A reflects that the calculation of the 2015 CACJA Rider will result in designed collection of $96,968,401 on an annualized basis and will be implemented on the effective date of new rates following this proceeding as set forth in more detail in the attached tariff. The CACJA rider is designed to provide for current recovery of costs for eligible projects through a thirteen (13)-month average of

[5] Although for purposes of settlement, the Settling Parties agree that the Company should be allowed to implement the CACJA rider on terms as established herein, the Settling Parties acknowledge that there was in fact no consensus as to whether the Company met the CACJA statutory criteria for the rider.

forecasted costs, but subject to true-up such that, only actual, prudently-incurred costs are recovered.

To be eligible to be included in the CACJA rider a cost must be incurred and associated with an investment that went into service between August 1, 2014 and December 31, 2017.

The Settling Parties agree that the statutory presumption of prudence applies to actual costs incurred in accordance with an approved emission reduction plan. (Sections 40-3.2-205(3) and 40-3.2-207(1)(a), C.R.S.) The Company recognizes its obligation to present robust direct testimony justifying expenditures as set out in Decision Nos. C12-0163 and C12-0159. The Company agrees to provide detailed cost information on an individual project basis and sufficient documentation to demonstrate that no costs in the CACJA rider are also being recovered in base rates. No cost item associated with any CACJA Project will be used to derive both the CACJA rider and base rates that would be in effect during the same given time period.

The CACJA rider will be ultimately limited to the collection of actual, prudently incurred amounts that are demonstrably tied to specific CACJA Projects, for which the Company already has a CPCN from the Commission. The CACJA rider will take into account all depreciation accrued on a monthly basis on any project for which the costs are reflected in whole or in part in the CACJA rider’s calculation. The WACC shall apply to earnings on CACJA investment. The after-tax WACC shall apply to amounts in the deferred balance.

2. TCA.

As set forth in Attachment A, the TCA effective concurrent with the implementation of rates from this proceeding will be $15,610,346 (reduced from the currently effective TCA of $31,660,232) until subsequently revised by the next approved TCA filing. The TCA rider tariff is included as Attachment D. The amounts included in Attachment D reflect a baseline of year-end December 31, 2013 plant in service balances and the costs allowed for recovery under Attachment D. Attachment D to this Settlement Agreement is a revised TCA tariff, which reflects that it will operate under the methodology as proposed by Public Service until the effective date of new rates from the 2017 Rate Case. In the 2017 Rate Case, the Company is free to propose a continuation of this methodology and other parties are free to propose and advocate other alternatives.

E. GRSA.

As shown on Attachment A, the incremental change to the GRSA resulting from the settled revenue requirement is negative 2.88%. The impact of this incremental change to the GRSA is reflected in the revised GRSA tariff included as Attachment K. The GRSA determined in this proceeding, when netted to the existing GRSA, results in a positive 14.19% GRSA.

F. Customer Impacts by Class.

The Settling Parties have included as Attachment B the incremental impact of the settlement on the average monthly total bills for the five major rate classes. These impacts reflect the estimated average monthly bills during 2015, 2016, and 2017 under the settlement as compared to the 2015 estimated average monthly bills without the settlement.

G. Earnings Test.

As part of this Settlement Agreement, the Settling Parties agree to an extension of the Earnings Test approved in Proceeding No. 11AL-947E that will apply annually to calendar years 2015, 2016, and 2017 with the following modified sharing thresholds and percentages:

Earned ROE	Sharing Percentages	
	Customers	Company
<= 9.83%	0%	100%
9.84% to 10.48%	50%	50%
>10.48%	100%	0%

The principles that shall apply to the implementation of the Earnings Test are set out in Attachment E to this Settlement Agreement, and are essentially the same as those approved by the Commission in Proceeding No. 11AL-947E, except as specifically modified herein. In addition, the following general principles apply:

- The earnings sharing amounts shall be determined annually on the basis of earnings test calculations.

- All Commission-ordered adjustments[6] and all accounting adjustments[7] as specifically described in Attachment E, except pro forma adjustments,[8] shall be made to such earnings test calculations.
- For purposes of the Earnings Test, rate case expenses will be included at $1,700,000 over a three year period (2015 through 2017) and the Mountain Pine Beetle amortization will be three years.
- In the event that the Company incurs a new cost or identifies an issue for which there is no previously established regulatory treatment subsequent to the date on which new base rates take effect as a result of the Commission's order, it shall identify such cost or issue in its earnings test filing together with the proposed regulatory treatment.

Public Service shall file earnings test information on or before April 30 of each year beginning April 30, 2016 and continuing through April 30, 2018. To the extent that the Company's earnings during the prior year exceed 9.83% return on equity, the Company shall also file an Advice letter seeking to put into effect, subject to true-up, a revised GRSA sufficient to refund to customers the proposed earnings sharing. The Staff and any other party that disputes the Company's earnings test information shall file notice with the Commission identifying any matters in the Company's earnings test filing

[6] Commission-ordered adjustments shall be defined as any adjustment adopted by the Commission to ensure that revenues, expenses, and rate base reflect traditional ratemaking principles (e.g., "just and reasonable" and "used and useful" standards.)

[7] Accounting adjustments shall be defined as any adjustment required to insure that transactions properly counted in the calculation of the review period's earnings are included in the annual filing and that transactions that are properly counted in the calculation of earnings for previous or future review periods are excluded.

[8] Pro forma adjustments shall be defined as annualization of price changes that occurred within the test year (in-period adjustments) or outside the test year (out-of-period adjustments).

with which such party takes issue and the basis for such dispute, no later than June 15 in any year. If all parties disputing the earnings sharing amount and the Company cannot resolve all of their differences by July 15, then all remaining disputes will be detailed in a written notice submitted to the Commission no later than August 1, together with a proposed procedural schedule for addressing such issues. Any over-collection of revenues resulting from the difference between the Earnings Sharing Adjustment ("ESA") ultimately approved by the Commission and the ESA implemented August 1 will be refunded to customers.

The ESA rider adopted here (Attachment J) shall continue to go into effect on August 1 of each year and shall remain in effect until July 31 of the following year or until modified in accordance with a Commission order issued as a result of an earnings test proceeding as described above.

In order to better facilitate review of the annual earnings test report by interested parties, the Company agrees to provide a table along with the earnings test reports that cross-references the applicable earnings test report and describing where in the earnings test report each regulatory principle identified in Attachment E to the Settlement Agreement has been incorporated.

H. Stay-Out Provision.

As part of this Settlement Agreement, the Company agrees that it will not seek any further changes in its base rates for retail electric service prior to the 2017 Rate Case, except as specifically provided below. When the Company files that rate case, it shall not propose an effective date such that new base rates will go into effect earlier than January 1, 2018, assuming the maximum 210-day suspension period.

This Section is not intended to limit the Company's ability to file (1) a Phase II rate case or other rate design changes that are intended to be revenue neutral; (2) new rates for customers with distributed generation;[9] (3) new standalone rates or charges for new voluntary service offerings or options; and (4) changes to or new non-rate terms and conditions.

1. GRSA to Reflect Material Changes in Expenses.

Notwithstanding this stay-out agreement, the Settling Parties agree that certain material changes in the Company's forecasted expenses are beyond Public Service's control and may require adjustment to the Company's GRSA then in effect or may be appropriate for deferral, provided that the change is reasonably expected to increase or decrease the Company's revenue requirement for its electric business by at least $10 million in that year. The types of cost changes that would qualify for a Regulatory Adjustment pursuant to this Section include:

- Changes in Generally Accepted Accounting Principles ("GAAP") that are appropriately reflected in rate regulation.
- Changes in tax laws other than property tax laws.
- Changes in Public Service's obligations stemming from changes in federal, state, or municipal laws, or regulations issued or actions taken by federal, state or local governmental bodies, including but not limited to the Environmental Protection Agency, the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation

[9] The Company recognizes that not all persons or entities may agree that new rates for customers with distributed generation are justified or reasonable and that the Commission is currently considering this issue in Proceeding No. 14M-0235E.

("NERC"), the Commission, the Colorado Department of Public Health and Environment, and local governments within the State of Colorado.

- Orders or acts of civil or military authority.
- Natural disasters or catastrophic events, net of any insurance proceeds.
- A Commission-approved asset acquisition or divestiture that exceeds $50 million.

The Company shall make a filing notifying all parties of any reductions or increases in its retail base rate revenue requirements that are or may be eligible for an adjustment under this Section within 60 days of the action or shall provide such notice in its Earnings Test filing on April 30th, whichever is earlier and shall either file an appropriate Advice Letter to change the GRSA or seek a deferral at the Company's discretion. The Settling Parties reserve their right to challenge prudency and the Company's calculation of the revenue requirement impact of such cost change.

2. GRSA Adjustment to Reflect Required Pre-Paid Pension Asset Filing.

In the event that the Company is permitted recovery associated with New Pre-Paid Pension Asset balances in accordance with Section *I*.C.6. (ii), the Company may request a new or modified GRSA.

3. Other Riders.

The Parties agree that currently existing riders applicable to the provision of electric service and not being modified in this Agreement (e.g., the Demand-Side Management Cost Adjustment or "DSMCA", etc.) will continue to apply and will be subject to periodic modification as specified in their respective tariffs. However, Public

Service will propose no new riders applicable to the provision of electric service to take effect during the stay out period.

I. Other Tariffs.

The Settling Parties agree that the following two tariffs should be allowed to go into effect as originally proposed and attached: Maintenance Charges for Street Lighting Service (Attachment H) and Schedule of Charges for Rendering Service (Attachment I).

I. Other Items Including Commitments Relating to Future Rate Filings

The Settling Parties also agree to the following provisions relating to specific issues that will require future filings, apply to the 2017 Rate Case, impose new reporting requirements, or may require subsequent filings.

A. Depreciation and Amortization Expense

The Company will continue to use the depreciation rates for its electric and common utility plant currently in effect as previously approved by the Commission prior to the filing of this proceeding. With respect to the regulatory assets/liabilities established for the Retired Generating Units,[10] the Company will continue to accrue annual amortization expense at the same level currently being accrued.[11] Upon the respective retirements of the Retiring Generating Units, the Company will establish regulatory assets in accordance with the accounting principles and procedures followed for the Retired Generation Units as previously approved by the Commission in Proceeding Nos. 09AL-299E and 11AL-947E. By April 1, 2016 the Company will file a comprehensive depreciation and amortization application before the Commission ("2016

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[10] As defined in the Company's testimony, "Retired Generating Units" refers to Cameo Units 1 & 2, Arapahoe Units 1 through 4, Cherokee Units 1 & 2 and Zuni Unit 1.

[11] As defined in the Company's testimony, "Retiring Generating Units" refers to Zuni Unit 2, Valmont Unit 3, and Cherokee Unit 3.

Depreciation Case") to address proposed changes to the depreciation rates, including without limitation, removal costs, net salvage, and amortization periods for its electric and common utility plant and the proposed amortization of the regulatory assets established for the Retired and Retiring Generating Units and potentially other production facilities retired or expected to be retired. The approved changes resulting from the 2016 Depreciation Case will be reflected in the 2017 Rate Case and the Settling Parties agree not to contest the implementation of any such approved changes from the 2016 Depreciation Case in the 2017 Rate Case. The Company shall not be required to record the depreciation and amortization changes approved in the 2016 Depreciation Case for accounting purposes until the effective date of new rates approved in the 2017 Rate Case and then only to the extent such approved depreciation and amortization changes are included in the development of such new rates. Incremental outside consultant and legal expenses incurred by the Company in preparing and defending the 2016 Depreciation Case will be eligible to be included in rate case expenses requested in the 2017 Rate Case.

B. Capital Structure.

Public Service commits to manage the equity component of the capital structure so that when rates become effective as a result of the 2017 Rate Case, the equity component of the actual capital structure will be lower than 56%. Until the effective date of approved rates resulting from the 2017 Rate Case, Public Service's Earnings Test and rate riders will be calculated based on the capital structure of Public Service as outlined in the applicable tariff provisions, but in no case will the equity portion of the capital structure be higher than 56%. Any change in Public Service's capital structure reflecting a lower equity component that occurs from February 13, 2015 until the effectiveness of rates approved in the 2017 Rate Case will be captured in applicable riders and calculation of the Earnings Test.

C. Other Items and Miscellaneous Future Rate Commitments.

1. Incentive Compensation.

The Settling Parties agree that AIP incentive payment recovery in the 2017 Rate Case will be capped at 15% of an employee's salary. In the 2017 Rate Case, the Company will also make an adjustment to the revenue requirement to reflect the removal of the pension expense impact relating to employee compensation for AIP above the Company's target incentive compensation. For the purposes of the Earnings Test, the AIP incentive payment recovery will be capped at 15% of an employee's salary, and the Company will be responsible for the pension expense impact relating to employee compensation for AIP above the Company's target incentive compensation.

2. Metro Ash Disposal Site.

In the event that Public Service sells this property in the future, Public Service will be entitled to retain 100% of any net proceeds or losses realized from such sale. Public Service will not include the property as plant held for future use in any future electric rate cases.

3. Oil & Gas Royalty Revenues.

For the purposes of the Earnings Test, the oil and gas royalty revenues are recognized to be shared 50/50. The Settling Parties agree that Public Service shall propose this same treatment in the 2017 Rate Case and the Settling Parties will not oppose such proposed treatment.

4. Arapahoe Decommissioning.

The Settling Parties accept Public Service's proposed Arapahoe decommissioning plan and recommend Commission authorization for Public Service to proceed with decommissioning and begin incurring costs. The Settlement Agreement does not reflect the Company's proposed mechanism to accelerate the recovery of the Arapahoe decommissioning costs beyond the level currently being amortized. The issue of the appropriate recovery mechanism will be taken up in the 2016 Depreciation Case.

5. Ponnequin Wind Farm.

The Settling Parties accept Public Service's proposed retirement of the Ponnequin Wind Farm ("Ponnequin"), and will not assert that Public Service is required to obtain a CPCN for the retirement of Ponnequin under Commission Rule 3103.

6. Equivalent Availability Factor Performance Mechanism.

The Settling Parties agree to an EAFPM as set forth below and incorporated in the attached ECA tariff (Attachment G).

The EAFPM will commence in 2015 and expire at the end of 2017. However, it will be reexamined in the Company's 2017 Rate Case. To facilitate such a reexamination, the Company will present a proposal in its 2017 Rate Case to either continue, modify, replace or discontinue the EAFPM going forward. In the event the Company proposes to continue or modify the EAFPM going forward, the Company will include in its direct testimony data regarding the benefits achieved by the expiring EAFPM.

(i) 2015:

For calendar year 2015, the Company will calculate its actual capacity weighted average EAF for the following generating units: Cherokee 4, 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. This actual capacity weighted average EAF calculation will be made using EAF data as reported to the North American Electric Reliability Corporation ("NERC") as part of its Generating Availability Data System ("GADS"). The Settling Parties agree the Company can adjust its EAF calculation only for outage events that are classified as Outside Management Control ("OMC") using NERC criteria and for outage events that are specifically attributable to an order of a state or federal regulatory agency or law.

The actual 2015 capacity weighted average EAF will be compared to two performance metrics. If the Company's actual 2015 capacity weighted average EAF is at or above 86.19 percent, the Company will receive an incentive payment of $3 million. If the Company's actual 2015 capacity weighted average EAF is at or below 83.79 percent, the Company will be assessed an incentive penalty of $3 million. If the Company's actual 2015 capacity weighted average EAF falls between 83.79 percent and 86.19 percent, the Company will neither earn an incentive payment nor be assessed an incentive penalty.

(ii) 2016 and 2017:

For calendar years 2016 and 2017, the Company will calculate its actual capacity weighted average EAF for the following generating units: 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. This actual capacity weighted average EAF calculation will be made using EAF data as reported to the NERC as part of its GADS. The Settling Parties agree the Company can adjust its EAF calculation only for outage events that are classified as OMC using NERC criteria and for outage events that are specifically attributable to an order of a state or federal regulatory agency or law.

The actual 2016 and 2017 capacity weighted average EAFs will be compared to two performance metrics. If the Company's actual 2016 or 2017 capacity weighted average EAF is at or above 86.57 percent, the Company will receive an incentive payment of $3 million. If the Company's actual 2016 or 2017 capacity weighted average EAF is at or below 84.49 percent, the Company will be assessed an incentive penalty of $3 million. If the Company's actual 2016 or 2017 capacity weighted average EAF falls between 84.49 percent and 86.57 percent, the Company will neither earn an incentive payment nor be assessed an incentive penalty.

(iii) Reporting and Evaluation

On or before April 1 of 2016, 2017, and 2018, the Company will make a separate filing to report the EAFPM performance results for the preceding calendar year. Once approved by the Commission, any incentive payment or incentive penalty will be reflected in the Company's ECA. Revisions to the ECA tariff to include the incentive penalty or incentive payment as described above are included as Attachment G to this Settlement Agreement.

General Provisions

1. The Settling Parties understand and agree that this Settlement Agreement represents a negotiated resolution of all issues that the Settling Parties either raised or

could have raised in this proceeding. The Settling Parties understand that the Commission's approval of this Settlement Agreement shall constitute a determination that the Settlement Agreement represents a just, equitable, and reasonable resolution of these issues. Accordingly, the Settling Parties state that reaching resolution of these issues in this proceeding through this negotiated Settlement Agreement is in the public interest and that the results of the compromises and agreements reflected in the Settlement Agreement are just, reasonable, and in the public interest.

2. The Settling Parties agree to join in a motion that requests that the Commission approve this Settlement Agreement, and to support the Settlement Agreement in any subsequent pleadings or filings. Each Settling Party further agrees that in the event that it sponsors a witness to address the Settlement Agreement at any hearing that the Commission may hold to address it, the Settling Party's witness will testify in support of the Settlement Agreement and the rates that will result from it, as well as all other terms and conditions of the Settlement Agreement. The Settling Parties agree to reasonably seek approval of this Settlement Agreement before the Commission against challenges that may be made by non-executing parties.

3. The Settling Parties agree that all their pre-filed testimony and exhibits, as previously corrected, shall be admitted into evidence in this proceeding without cross-examination by the Settling Parties.

4. Except as expressly stated herein, nothing in this Settlement Agreement shall resolve any principle or establish any precedent or settled practice.

5. Notwithstanding that this Settlement Agreement specifies that the agreed to rates have been developed based on certain principles (e.g., a 9.83% return on

equity) and that certain principles are to apply to the Settling Parties in specified subsequent proceedings, nothing in this Settlement Agreement shall constitute an admission by any Settling Party of the correctness or general applicability of any such principle, or any claim, defense, rule, or interpretation of law, allegation of fact, regulatory policy, or other principle underlying or thought to underlie this Settlement Agreement or any of its provisions in this or any other proceeding. As a consequence, no Settling Party in any future negotiations or proceedings whatsoever (other than any proceeding involving the honoring, enforcing, or construing of this Settlement Agreement in those proceedings specified in this Settlement Agreement, and only to the extent, so specified) shall be bound or prejudiced by any provision of this Settlement Agreement.

6. Insofar as this Settlement Agreement includes the agreement on rate principles to be recognized in specified subsequent proceedings, Public Service shall propose rates that reflect those principles, as applicable, and the other Settling Parties shall not take positions contesting those rates that contravene those principles.

7. The discussions among the Settling Parties that have produced this Settlement Agreement have been conducted with the understanding, pursuant to Colorado law, that all offers of settlement, and discussions relating thereto, are and shall be privileged and shall be without prejudice to the position of any of the Settling Parties and are not to be used in any manner in connection with this or any other proceeding.

8. This Settlement Agreement shall not become effective until the issuance of a final Commission Order approving the Settlement Agreement, which Order does

not contain any modification of the terms and conditions of this Settlement Agreement that is unacceptable to any of the Settling Parties. In the event the Commission modifies this Settlement Agreement in a manner unacceptable to any Settling Party, that Settling Party shall have the right to withdraw from this Agreement and proceed to hearing on the issues that may be appropriately raised by that Settling Party in this proceeding. The withdrawing Settling Party shall notify the Commission and the Settling Parties to this Agreement by e-mail within three business days of the Commission modification that the party is withdrawing from the Settlement Agreement and that the party desires to proceed to hearing; the e-mail notice shall designate the precise issue or issues on which the party desires to proceed to hearing (the “Hearing Notice”).

9. The withdrawal of a Settling Party shall not automatically terminate this Agreement as to any other party. However, within three business days of the date of the Hearing Notice from the first withdrawing party, all Settling Parties shall confer to arrive at a comprehensive list of issues that shall proceed to hearing and a list of issues that remain settled as a result of the first party’s withdrawal from this Settlement Agreement. Within five business days of the date of the Hearing Notice, the Settling Parties shall file with the Commission a formal notice containing the list of issues that shall proceed to hearing and those issues that remain settled together with a proposed procedural schedule. The Settling Parties who proceed to hearing shall have and be entitled to exercise all rights with respect to the issues that are heard that they would have had in the absence of this Settlement Agreement.

10. All Parties have had the opportunity to participate in the drafting of this Settlement Agreement and the term sheet upon which it was based. There shall be no

legal presumption that any specific Settling Party was the drafter of this Settlement Agreement.

11. This Settlement Agreement may be executed in counterparts, all of which when taken together shall constitute the entire Settlement Agreement with respect to the issues addressed by this Agreement.

Dated this 23rd day of January, 2015.

Agreed on behalf of:

PUBLIC SERVICE COMPANY OF COLORADO

By: ______________________
Alice K. Jackson
Regional Vice President, Rates and Regulatory Affairs

Approved as to Form:

By: ______________________
William M. Dudley
Lead Assistant General Counsel

Dated 23rd day of January 2015

Agreed on behalf of:

TRIAL STAFF OF THE COLORADO PUBLIC UTILITIES COMMISSION

By : ______________________

Charles B. Hernandez, CPA
Chief Economist and Energy Financial Section Chief
1560 Broadway, Suite 250
Denver, CO 80202
Telephone: 303.894.2901
Email:
charles.hernandez@state.co.us

Approved as to form:

CYNTHIA H. COFFMAN
Attorney General

____

Michael J. Santisi, #29673*
David M. Nocera, #28776*
Senior Assistant Attorneys General
Paul J. Kyed, #37814*
Kristen L. Fischer, #46119*
Assistant Attorneys General
Revenue and Utilities Section

Counsel for Trial Staff of the Public Utilities Commission

*Counsel of Record

Ralph L. Carr Colorado Judicial Center
1300 Broadway, 8th Floor
Denver, Colorado 80203
Telephone:
720.508.6330 (Santisi)
720.508.6333 (Nocera)
720.508.6332 (Kyed)
720.508.6762 (Fischer)
Fax: 720.508.6038
Emails:
michael.santisi@state.co.us
dave.nocera@state.co.us
paul.kyed@state.co.us
kristen.fischer@state.co.us

Dated this 23rd day of January, 2015.

Agreed on behalf of:

COLORADO OFFICE OF CONSUMER COUNSEL

BY: Cindy Z. Schonhaut

Cindy Z. Schonhaut
Director
Office of Consumer Counsel
1560 Broadway, Suite 200
Denver, CO 80202

Approved as to Form:

BY: Thomas F. Dixon

Thomas F. Dixon, Colo. Reg. No. 500
First Assistant Attorney General
Office of the Attorney General
1300 Broadway, 7^{th} Floor
Denver, CO 80203

Dated this 23rd day of January, 2015

HOLLAND & HART LLP

Thorvald A. Nelson, #24715
Michelle Brandt King, # 35048
6380 South Fiddlers Green Circle, Suite 500
Greenwood Village, CO 80111
Telephone: (303) 290-1601 and x1097, respectively
tnelson@hollandhart.com
mbking@hollandhart.com

ATTORNEYS FOR COLORADO
ENERGY CONSUMERS

Dated this 23rd day of January, 2015.

Agreed on behalf of:

COLORADO HEALTHCARE ELECTRIC COORDINATING COUNCIL

By: Mark Sundback wr
Mark F. Sundback
Attorney for the Colorado Healthcare Electric Coordinating Council

Approved as to Form:

By: Wm M Rappolt
William M. Rappolt
Attorney for the Colorado Healthcare Electric Coordinating Council

Dated this 23rd day of January, 2015

DUFFORD & BROWN, P.C.

Richard L. Fanyo, Reg. No. 7238
Mark T. Valentine, Reg. No. 29986
1700 Broadway, Suite #2100
Denver, CO 80290-2101
Tel: 303-861-8013
Fax: 303-832-3804
Email: Rfanyo@duffordbrown.com
mvalentine@duffordbrown.com

Attorneys for Climax Molybdenum Company
and CF&I Steel, LP

Dated this 23rd day of January, 2015.

Agreed on behalf of:

FEDERAL EXECUTIVE AGENCIES

By: ______________________
JOHN C. DEGNAN, Lt Col, USAF
AFLOA/JACE-ULFSC

And,

By: ______________________
THOMAS A. JERNIGAN, Esq.
AFCEC/JA-ULFSC

Dated this 23rd day of January, 2015

GREENBERG TRAURIG

Meshach Y. Rhoades, Esq. (*CO Bar #35965)*
1200 17th Street, Suite 2400
Denver, Colorado 80203
Phone: (303) 572-6500
Fax: (303) 572-6540
rhoadesm@gtlaw.com

ATTORNEYS FOR WAL-MART, INC. AND
SAM'S WEST INC.

Dated this 23rd day of January, 2015.

Agreed on behalf of:

KROGER CO.

By: ______________________
[Name] Kurt J. Boehm
[Title] attorney for Kroger Co.

Approved as to Form:

By: ______________________
[Name]
[Title]

Dated this 23rd day of January, 2015.

Agreed on behalf of:

ENERGY OUTREACH COLORADO

By: ______________________________

Sanders Arnold
Executive Director
225 E. 16th Ave., Suite 200
Denver, CO 80203
303-226-5050
sarnold@energyoutreach.org

Approved as to Form:

By: ______________________________

Jeffrey G. Pearson
Pro Bono/Emeritus No. 5874/13PB0051
Jeffrey G. Pearson, LLC
1570 Emerson Street
Denver, CO 80218
Tel: 303.618.0686
Fax: 303.837.1557
jpearson@jgp-law.com

Public Service Company of Colorado
Proceeding No. 14AL-0660E
Settled Revenue Requirement

Line No.			2013 HTY
1	**As Filed Revenue Deficiency based on 2nd Revised Attachment No. DAB-3**	$	4,540,070
2			
3	**Settlement Adjustments**		
4	Return on Equity at 9.83%	$	(21,714,753)
5	Cost of Debt at 4.67%		3,156
6	15 Year Amortization of Net Prepaid Pension Asset at December 31, 2014		9,488,773
7			
8	**Total Settlement Adjustments**	**$**	**(12,222,824)**
9			
10	**Total Revenue Deficiency**	**$**	**(7,682,754)**
11			
12	Other Revenue Requirement Adjustments	**$**	**(31,735,761)**
13			
14	**Base Rate Decrease**	**$**	**(39,418,515)**
15			
16	**Riders**		
17	CACJA Rider Revenue		$96,968,401
18	TCA Rider Revenue		15,610,346
19	**Total Rider Revenue**		**$112,578,747**
20			
21	**Grand Total New Revevenue**		**$73,160,232**
22	Less: Existing TCA Rider Revenue		(31,660,232)
23	**Net Increase - Customer Impact**	**$**	**41,500,000**
24			
25			
26	**GRSA Calculation:**		
27			
28	Retail Base Rate Revenue (Attachment No. 2nd Revised DAB-3, Schedule 42)	$	1,597,444,843
29			
30	Less: Current 17.07% GRSA Rider Revenues		232,502,350
31	Less: Street Light Maintenance Revenue		2,530,414
32	Plus: Energy Affordability Program		4,086,700
33			
34	Rider Applicable Revenue	$	1,366,498,780
35			
36	**GRSA Rider (line 14 / line 34)**		**-2.88%**

(1) The Revenue Requirement impact of the annual amortization of the Legacy Pre-Paid Pension asset ($139,137,447/15 yrs. = $9,275,830)

Public Service Company of Colorado
Electric Department

INCREMENTAL BILL IMPACTS OF SETTLEMENT (2015 - 2017)

2015-2015

Rate Class	2015 Monthly Bill w/o the Settlement	2015 Monthly Bill with the Settlement	Monthly Difference $	Monthly Bill Difference %	Cummulative % Change from 2015
R	$ 73.45	$ 74.41	$ 0.96	1.31%	1.31%
C	$ 123.54	$ 125.37	$ 1.83	1.48%	1.48%
SG	$ 2,465.45	$ 2,509.21	$ 43.76	1.77%	1.77%
PG	$ 36,799.35	$ 37,407.02	$ 607.67	1.65%	1.65%
TG	$ 782,705.11	$ 797,879.20	$ 15,174.09	1.94%	1.94%

2015-2016

Rate Class	2015 Monthly Bill with the Settlement	2016 Monthly Bill	Monthly Difference $	Monthly Bill Difference %	Cummulative % Change from 2015
R	$ 74.41	$ 74.90	$ 0.49	0.66%	1.97%
C	$ 125.37	$ 126.23	$ 0.86	0.69%	2.18%
SG	$ 2,509.21	$ 2,527.32	$ 18.11	0.72%	2.51%
PG	$ 37,407.02	$ 37,640.40	$ 233.38	0.62%	2.29%
TG	$ 797,879.20	$ 802,587.38	$ 4,708.18	0.59%	2.54%

2016-2017

Rate Class	2016 Monthly Bill	2017 Monthly Bill	Monthly Difference $	Monthly Bill Difference %	Cummulative % Change from 2015
R	$ 74.90	$ 74.82	$ (0.08)	-0.11%	1.87%
C	$ 126.23	$ 126.08	$ (0.15)	-0.12%	2.06%
SG	$ 2,527.32	$ 2,524.42	$ (2.90)	-0.11%	2.39%
PG	$ 37,640.40	$ 37,597.97	$ (42.43)	-0.11%	2.17%
TG	$ 802,587.38	$ 801,843.98	$ (743.40)	-0.09%	2.45%

Notes:
1. ESA is held constant at end of year 2014 level for all three years.
2. For each class the DSMCA, PCCA, ECA and RESA are held constant at 2015 levels for all three years.
3. For each class the decline in the TCA resulting from the Settlement is included in the 2015 bill impact. The TCA is then assumed to remain at that level in 2016 and 2017.
4. For each class the 2015 CACJA Rider is based on the 2015 CACJA revenue requirement specified in the Settlement. The 2016 and 2017 CACJA Riders are based on the projected 2016 class billing determinants and the projected 2016 and 2017 CACJA revenue requirements provided on Page 1 of 2nd Revised Attachment No. DAB-15.

Public Service Company of Colorado
Proceeding No. 14AL-0660E
Customer Impact Study 2015-2015
Base, TCA and CACJA Rate Impact

Please Note:
***ESA is 8/2014 rate**

Customer Class	2015 Rate		Proposed 2015 Rate		Monthly Average Usage		2015 Bill		Proposed 2015 Bill		Monthly Difference $	Difference %
Residential - Schedule R												
Service and Facility Charge	$	6.75	$	6.75			$	6.75	$	6.75	$ -	
Energy Charge - Annualized	$	0.05177 /kWh	$	0.05177 /kWh	632 kWh			32.72		32.72	-	
Subtotal							$	39.47	$	39.47	$ -	0.00%
GRSA		**17.07%**		**14.19%**				**6.74**		**5.60**	**(1.14)**	
*ESA		-3.35%		-3.35%				(1.32)		(1.32)		
Base Rate Amount							$	44.89	$	43.75	$ (1.14)	-2.54%
DSMCA	$	0.00244 /kWh	$	0.00244 /kWh			$	1.54	$	1.54	$ -	
PCCA	$	0.00650 /kWh	$	0.00650 /kWh			$	4.11	$	4.11	$ -	
CACJA	**$**	**- /kWh**	**$**	**0.00392 /kWh**			**$**	**-**	**$**	**2.48**	**$ 2.48**	
TCA	**$**	**0.00127 /kWh**	**$**	**0.00063 /kWh**			**$**	**0.80**	**$**	**0.40**	**$ (0.40)**	
ECA - Secondary	$	0.03271 /kWh	$	0.03271 /kWh			$	20.67	$	20.67	$ -	
Subtotal Base Rate Adjustments							$	27.12	$	29.20	$ 2.08	
Total Bill Subtotal							$	72.01	$	72.95	$ 0.94	1.31%
RESA		2.00%		2.00%			$	1.44	$	1.46	$ 0.02	
Total Bill							$	73.45	$	74.41	$ 0.96	**1.31%**
Commercial - Schedule C												
Service and Facility Charge	$	10.75	$	10.75			$	10.75	$	10.75	$ -	
Energy Charge - Annualized	$	0.04763 /kWh	$	0.04763 /kWh	1,123 kWh			53.49		53.49	-	
Subtotal							$	64.24	$	64.24	$ -	0.00%
GRSA		**17.07%**		**14.19%**				**10.97**		**9.12**	**(1.85)**	
*ESA		-3.35%		-3.35%				(2.15)		(2.15)		
Base Rate Amount							$	73.06	$	71.21	$ (1.85)	-2.53%
DSMCA	$	0.00241 /kWh	$	0.00241 /kWh			$	2.71	$	2.71	$ -	
PCCA	$	0.00642 /kWh	$	0.00642 /kWh			$	7.21	$	7.21	$ -	
CACJA	**$**	**- /kWh**	**$**	**0.00387 /kWh**			**$**	**-**	**$**	**4.35**	**$ 4.35**	
TCA	**$**	**0.00126 /kWh**	**$**	**0.00062 /kWh**			**$**	**1.41**	**$**	**0.70**	**$ (0.71)**	
ECA - Secondary	$	0.03271 /kWh	$	0.03271 /kWh			$	36.73	$	36.73	$ -	
Subtotal Base Rate Adjustments							$	48.06	$	51.70	$ 3.64	
Total Bill Subtotal							$	121.12	$	122.91	$ 1.79	1.48%
RESA		2.00%		2.00%			$	2.42	$	2.46	$ 0.04	
Total Bill							$	123.54	$	125.37	$ 1.83	**1.48%**

Public Service Company of Colorado
Proceeding No. 14AL-0660E
Customer Impact Study 2015-2015

Customer Class	2015 Rate	Proposed 2015 Rate	Monthly Average Usage	2015 Bill	Proposed 2015 Bill	Monthly Difference $	Difference %
Secondary General - Schedule SG							
Service and Facility Charge	$ 40.00	$ 40.00	51.49% L.F.	$ 40.00	$ 40.00	$ -	
Energy Charge	$ 0.00473 kWh	$ 0.00473 kWh	26,685 kWh	126.22	126.22	-	
Distribution Demand Charge	$ 4.84 /kW	$ 4.84 /kW	71.00 kW	343.64	343.64	-	
G & T Demand Charge - Annualized	$ 8.99 /kW	$ 8.99 /kW	71.00 kW	638.29	638.29	-	
Subtotal				$ 1,148.15	$ 1,148.15	$ -	0.00%
GRSA	**17.07%**	**14.19%**		**195.99**	**162.92**	**(33.07)**	
*ESA	-3.35%	-3.35%		(38.46)	(38.46)		
Base Rate Amount				$ 1,305.68	$ 1,272.61	$ (33.07)	-2.53%
DSMCA	$ 0.81 /kW	$ 0.81 /kW		$ 57.51	$ 57.51	$ -	
PCCA	$ 2.13 /kW	$ 2.13 /kW		$ 151.23	$ 151.23	$ -	
CACJA	**$ - /kW**	**$ 1.28 /kW**		**$ -**	**$ 90.88**	**$ 90.88**	
TCA	**$ 0.42 /kW**	**$ 0.21 /kW**		**$ 29.82**	**$ 14.91**	**$ (14.91)**	
ECA - Secondary	$ 0.03271 /kWh	$ 0.03271 /kWh		$ 872.87	$ 872.87	$ -	
Subtotal Base Rate Adjustments				$ 1,111.43	$ 1,187.40	$ 75.97	
Total Bill Subtotal				$ 2,417.11	$ 2,460.01	$ 42.90	1.77%
RESA	2.00%	2.00%		$ 48.34	$ 49.20	$ 0.86	
Total Bill				$ 2,465.45	$ 2,509.21	$ 43.76	**1.77%**
Primary General - Schedule PG							
Service and Facility Charge	$ 305.00	$ 305.00	64.82% L.F.	$ 305.00	$ 305.00	$ -	
Energy Charge	$ 0.00461 kWh	$ 0.00461 kWh	492,079 kWh	2,268.48	2,268.48	-	
Distribution Demand Charge	$ 3.98 /kW	$ 3.98 /kW	1,040.00 kW	4,139.20	4,139.20	-	
G & T Demand Charge - Annualized	$ 8.03 /kW	$ 8.03 /kW	1,040.00 kW	8,351.20	8,351.20	-	
Subtotal				$ 15,063.88	$ 15,063.88	$ -	0.00%
GRSA	**17.07%**	**14.19%**		**2,571.40**	**2,137.56**	**(433.84)**	
*ESA	-3.35%	-3.35%		(504.64)	(504.64)		
Base Rate Amount				$ 17,130.64	$ 16,696.80	$ (433.84)	-2.53%
DSMCA	$ 0.75 /kW	$ 0.75 /kW		$ 780.00	$ 780.00	$ -	
PCCA	$ 1.98 /kW	$ 1.98 /kW		$ 2,059.20	$ 2,059.20	$ -	
CACJA	**$ - /kW**	**$ 1.19 /kW**		**$ -**	**$ 1,237.60**	**$ 1,237.60**	
TCA	**$ 0.40 /kW**	**$ 0.20 /kW**		**$ 416.00**	**$ 208.00**	**$ (208.00)**	
ECA - Primary On-Peak (1)	$ 0.03987 /kWh	$ 0.03987 /kWh		$ 7,509.44	$ 7,509.44	$ -	
ECA - Primary Off-Peak (1)	$ 0.02694 /kWh	$ 0.02694 /kWh		$ 8,182.51	$ 8,182.51	$ -	
Subtotal Base Rate Adjustments				$ 18,947.15	$ 19,976.75	$ 1,029.60	
Total Bill Subtotal				$ 36,077.79	$ 36,673.55	$ 595.76	1.65%
RESA	2.00%	2.00%		$ 721.56	$ 733.47	$ 11.91	
Total Bill				$ 36,799.35	$ 37,407.02	$ 607.67	**1.65%**

(1) Assumes 38.276% on-peak and 61.724% off-peak usage factors.

Public Service Company of Colorado
Electric Department
Customer Impact Study 2015-2015

Customer Class	2015 Rate			Proposed 2015 Rate			Monthly Average Usage		2015 Bill		Proposed 2015 Bill		Monthly Difference $		Difference %
Transmission General - Schedule TG															
Service and Facility Charge	$	14,800.00		$	14,800.00		72.68%	L.F.	$	14,800.00	$	14,800.00	$	-	
Energy Charge	$	0.00451	/kWh	$	0.00451	/kWh	12,889,873	kWh		58,133.33		58,133.33		-	
Demand Charge - Annualized	$	7.68	/kW	$	7.68	/kW	24,294	kW		186,577.92		186,577.92		-	
Subtotal									$	259,511.25	$	259,511.25	$	-	0.00%
GRSA		**17.07%**			**14.19%**					**44,298.57**		**36,824.65**		**(7,473.92)**	
*ESA		-3.35%			-3.35%					(8,693.63)		(8,693.63)			
Base Rate Amount									$	295,116.19	$	287,642.27	$	(7,473.92)	-2.53%
DSMCA	$	0.70	/kW	$	0.70	/kW			$	17,005.80	$	17,005.80	$	-	
PCCA	$	1.84	/kW	$	1.84	/kW			$	44,700.96	$	44,700.96	$	-	
CACJA	**$**	**-**	**/kW**	**$**	**1.11**	**/kW**			**$**	**-**	**$**	**26,966.34**	**$**	**26,966.34**	
TCA	**$**	**0.37**	**/kW**	**$**	**0.18**	**/kW**			**$**	**8,988.78**	**$**	**4,372.92**	**$**	**(4,615.86)**	
ECA - Transmission On-Peak (2)	$	0.03929	/kWh	$	0.03929	/kWh			$	182,942.44	$	182,942.44	$	-	
ECA - Transmission Off-Peak (2)	$	0.02655	/kWh	$	0.02655	/kWh			$	218,603.78	$	218,603.78	$	-	
Subtotal Base Rate Adjustments									$	472,241.76	$	494,592.24	$	22,350.48	
Total Bill Subtotal									$	767,357.95	$	782,234.51	$	14,876.56	1.94%
RESA		2.00%			2.00%				$	15,347.16	$	15,644.69	$	297.53	
Total Bill									$	782,705.11	$	797,879.20	$	15,174.09	**1.94%**

(2) Assumes 36.123% on-peak and 63.877% off-peak usage factors.

Public Service Company of Colorado
Electric Department
Customer Impact Study 2015-2016
Base, TCA and CACJA Rate Impact

Please Note:
***ESA is 8/2014 rate**

Customer Class	Proposed 2015 Rate	Proposed 2016 Rate	Monthly Average Usage	Proposed 2015 Bill	Proposed 2016 Bill	Monthly Difference $	Difference %
Residential - Schedule R							
Service and Facility Charge	$ 6.75	$ 6.75		$ 6.75	$ 6.75	$ -	
Energy Charge - Annualized	$ 0.05177 /kWh	$ 0.05177 /kWh	632 kWh	32.72	32.72	-	
Subtotal				$ 39.47	$ 39.47	$ -	0.00%
GRSA	14.19%	14.19%		5.60	5.60	-	
*ESA	-3.35%	-3.35%		(1.32)	(1.32)		
Base Rate Amount				$ 43.75	$ 43.75	$ -	0.00%
DSMCA	$ 0.00244 /kWh	$ 0.00244 /kWh		$ 1.54	$ 1.54	$ -	
PCCA	$ 0.00650 /kWh	$ 0.00650 /kWh		$ 4.11	$ 4.11	$ -	
CACJA	**$ 0.00392 /kWh**	**$ 0.00468 /kWh**		**$ 2.48**	**$ 2.96**	**$ 0.48**	
TCA	$ 0.00063 /kWh	$ 0.00063 /kWh		$ 0.40	$ 0.40	$ -	
ECA - Secondary	$ 0.03271 /kWh	$ 0.03271 /kWh		$ 20.67	$ 20.67	$ -	
Subtotal Base Rate Adjustments				$ 29.20	$ 29.68	$ 0.48	
Total Bill Subtotal				$ 72.95	$ 73.43	$ 0.48	0.66%
RESA	2.00%	2.00%		$ 1.46	$ 1.47	$ 0.01	
Total Bill				$ 74.41	$ 74.90	$ 0.49	**0.66%**
Commercial - Schedule C							
Service and Facility Charge	$ 10.75	$ 10.75		$ 10.75	$ 10.75	$ -	
Energy Charge - Annualized	$ 0.04763 /kWh	$ 0.04763 /kWh	1,123 kWh	53.49	53.49	-	
Subtotal				$ 64.24	$ 64.24	$ -	0.00%
GRSA	14.19%	14.19%		9.12	9.12	-	
*ESA	-3.35%	-3.35%		(2.15)	(2.15)		
Base Rate Amount				$ 71.21	$ 71.21	$ -	0.00%
DSMCA	$ 0.00241 /kWh	$ 0.00241 /kWh		$ 2.71	$ 2.71	$ -	
PCCA	$ 0.00642 /kWh	$ 0.00642 /kWh		$ 7.21	$ 7.21	$ -	
CACJA	**$ 0.00387 /kWh**	**$ 0.00462 /kWh**		**$ 4.35**	**$ 5.19**	**$ 0.84**	
TCA	$ 0.00062 **/kWh**	$ 0.00062 **/kWh**		**$ 0.70**	**$ 0.70**	**$ -**	
ECA - Secondary	$ 0.03271 /kWh	$ 0.03271 /kWh		$ 36.73	$ 36.73	$ -	
Subtotal Base Rate Adjustments				$ 51.70	$ 52.54	$ 0.84	
Total Bill Subtotal				$ 122.91	$ 123.75	$ 0.84	0.68%
RESA	2.00%	2.00%		$ 2.46	$ 2.48	$ 0.02	
Total Bill				$ 125.37	$ 126.23	$ 0.86	**0.69%**

Public Service Company of Colorado
Electric Department
Customer Impact Study 2015-2016

Customer Class	Proposed 2015 Rate	Proposed 2016 Rate	Monthly Average Usage	Proposed 2015 Bill	Proposed 2016 Bill	Monthly Difference $	Difference %
Secondary General - Schedule SG							
Service and Facility Charge	$ 40.00	$ 40.00	51.49% L.F.	$ 40.00	$ 40.00	$ -	
Energy Charge	$ 0.00473 kWh	$ 0.00473 kWh	26,685 kWh	126.22	126.22	-	
Distribution Demand Charge	$ 4.84 /kW	$ 4.84 /kW	71.00 kW	343.64	343.64	-	
G & T Demand Charge - Annualized	$ 8.99 /kW	$ 8.99 /kW	71.00 kW	638.29	638.29	-	
Subtotal				$ 1,148.15	$ 1,148.15	$ -	0.00%
GRSA	14.19%	14.19%		162.92	162.92	-	
*ESA	-3.35%	-3.35%		(38.46)	(38.46)		
Base Rate Amount				$ 1,272.61	$ 1,272.61	$ -	0.00%
DSMCA	$ 0.81 /kW	$ 0.81 /kW		$ 57.51	$ 57.51	$ -	
PCCA	$ 2.13 /kW	$ 2.13 /kW		$ 151.23	$ 151.23	$ -	
CACJA	**$ 1.28 /kW**	**$ 1.53 /kW**		**$ 90.88**	**$ 108.63**	**$ 17.75**	
TCA	$ 0.21 /kW	$ 0.21 /kW		$ 14.91	$ 14.91	$ -	
ECA - Secondary	$ 0.03271 /kWh	$ 0.03271 /kWh		$ 872.87	$ 872.87	$ -	
Subtotal Base Rate Adjustments				$ 1,187.40	$ 1,205.15	$ 17.75	
Total Bill Subtotal				$ 2,460.01	$ 2,477.76	$ 17.75	0.72%
RESA	2.00%	2.00%		$ 49.20	$ 49.56	$ 0.36	
Total Bill				$ 2,509.21	$ 2,527.32	$ 18.11	**0.72%**
Primary General - Schedule PG							
Service and Facility Charge	$ 305.00	$ 305.00	64.82% L.F.	$ 305.00	$ 305.00	$ -	
Energy Charge	$ 0.00461 kWh	$ 0.00461 kWh	492,079 kWh	2,268.48	2,268.48	-	
Distribution Demand Charge	$ 3.98 /kW	$ 3.98 /kW	1,040.00 kW	4,139.20	4,139.20	-	
G & T Demand Charge - Annualized	$ 8.03 /kW	$ 8.03 /kW	1,040.00 kW	8,351.20	8,351.20	-	
Subtotal				$ 15,063.88	$ 15,063.88	$ -	0.00%
GRSA	14.19%	14.19%		2,137.56	2,137.56	-	
*ESA	-3.35%	-3.35%		(504.64)	(504.64)		
Base Rate Amount				$ 16,696.80	$ 16,696.80	$ -	0.00%
DSMCA	$ 0.75 /kW	$ 0.75 /kW		$ 780.00	$ 780.00	$ -	
PCCA	$ 1.98 /kW	$ 1.98 /kW		$ 2,059.20	$ 2,059.20	$ -	
CACJA	**$ 1.19 /kW**	**$ 1.41 /kW**		**$ 1,237.60**	**$ 1,466.40**	**$ 228.80**	
TCA	$ 0.20 /kW	$ 0.20 /kW		$ 208.00	$ 208.00	$ -	
ECA - Primary On-Peak (1)	$ 0.03987 /kWh	$ 0.03987 /kWh		$ 7,509.44	$ 7,509.44	$ -	
ECA - Primary Off-Peak (1)	$ 0.02694 /kWh	$ 0.02694 /kWh		$ 8,182.51	$ 8,182.51	$ -	
Subtotal Base Rate Adjustments				$ 19,976.75	$ 20,205.55	$ 228.80	
Total Bill Subtotal				$ 36,673.55	$ 36,902.35	$ 228.80	0.62%
RESA	2.00%	2.00%		$ 733.47	$ 738.05	$ 4.58	
Total Bill				$ 37,407.02	$ 37,640.40	$ 233.38	**0.62%**

(1) Assumes 38.276% on-peak and 61.724% off-peak usage factors.

Public Service Company of Colorado
Electric Department
Customer Impact Study 2015-2016

Customer Class	Proposed 2015 Rate		Proposed 2016 Rate		Monthly Average Usage		Proposed 2015 Bill	Proposed 2016 Bill	Monthly Difference $	Difference %
Transmission General - Schedule TG										
Service and Facility Charge	$ 14,800.00		$ 14,800.00		72.68%	L.F.	$ 14,800.00	$ 14,800.00	$ -	
Energy Charge	$ 0.00451	/kWh	$ 0.00451	/kWh	12,889,873	kWh	58,133.33	58,133.33	-	
Demand Charge - Annualized	$ 7.68	/kW	$ 7.68	/kW	24,294	kW	186,577.92	186,577.92	-	
Subtotal							$ 259,511.25	$ 259,511.25	$ -	0.00%
GRSA	14.19%		14.19%				36,824.65	36,824.65	-	
*ESA	-3.35%		-3.35%				(8,693.63)	(8,693.63)		
Base Rate Amount							$ 287,642.27	$ 287,642.27	$ -	0.00%
DSMCA	$ 0.70	/kW	$ 0.70	/kW			$ 17,005.80	$ 17,005.80	$ -	
PCCA	$ 1.84	/kW	$ 1.84	/kW			$ 44,700.96	$ 44,700.96	$ -	
CACJA	**$ 1.11**	**/kW**	**$ 1.30**	**/kW**			**$ 26,966.34**	**$ 31,582.20**	**$ 4,615.86**	
TCA	$ 0.18	/kW	$ 0.18	/kW			$ 4,372.92	$ 4,372.92	$ -	
ECA - Transmission On-Peak (2)	$ 0.03929	/kWh	$ 0.03929	/kWh			$ 182,942.44	$ 182,942.44	$ -	
ECA - Transmission Off-Peak (2)	$ 0.02655	/kWh	$ 0.02655	/kWh			$ 218,603.78	$ 218,603.78	$ -	
Subtotal Base Rate Adjustments							$ 494,592.24	$ 499,208.10	$ 4,615.86	
Total Bill Subtotal							$ 782,234.51	$ 786,850.37	$ 4,615.86	0.59%
RESA	2.00%		2.00%				$ 15,644.69	$ 15,737.01	$ 92.32	
Total Bill							$ 797,879.20	$ 802,587.38	$ 4,708.18	**0.59%**

(2) Assumes 36.123% on-peak and 63.877% off-peak usage factors.

Public Service Company of Colorado
Electric Department
Customer Impact Study 2016-2017
Base, TCA and CACJA Rate Impact

Please Note:
***ESA is 8/2014 rate**

Customer Class	Proposed 2016 Rate	Proposed 2017 Rate	Monthly Average Usage	Proposed 2016 Bill	Proposed 2017 Bill	Monthly Difference $	Difference %
Residential - Schedule R							
Service and Facility Charge	$ 6.75	$ 6.75		$ 6.75	$ 6.75	$ -	
Energy Charge - Annualized	$ 0.05177 /kWh	$ 0.05177 /kWh	632 kWh	32.72	32.72	-	
Subtotal				$ 39.47	$ 39.47	$ -	0.00%
GRSA	14.19%	14.19%		5.60	5.60	-	
*ESA	-3.35%	-3.35%		(1.32)	(1.32)		
Base Rate Amount				$ 43.75	$ 43.75	$ -	0.00%
DSMCA	$ 0.00244 /kWh	$ 0.00244 /kWh		$ 1.54	$ 1.54	$ -	
PCCA	$ 0.00650 /kWh	$ 0.00650 /kWh		$ 4.11	$ 4.11	$ -	
CACJA	**$ 0.00468 /kWh**	**$ 0.00455 /kWh**		**$ 2.96**	**$ 2.88**	**$ (0.08)**	
TCA	$ 0.00063 /kWh	$ 0.00063 /kWh		$ 0.40	$ 0.40	$ -	
ECA - Secondary	$ 0.03271 /kWh	$ 0.03271 /kWh		$ 20.67	$ 20.67	$ -	
Subtotal Base Rate Adjustments				$ 29.68	$ 29.60	$ (0.08)	
Total Bill Subtotal				$ 73.43	$ 73.35	$ (0.08)	-0.11%
RESA	2.00%	2.00%		$ 1.47	$ 1.47	$ -	
Total Bill				$ 74.90	$ 74.82	$ (0.08)	**-0.11%**
Commercial - Schedule C							
Service and Facility Charge	$ 10.75	$ 10.75		$ 10.75	$ 10.75	$ -	
Energy Charge - Annualized	$ 0.04763 /kWh	$ 0.04763 /kWh	1,123 kWh	53.49	53.49	-	
Subtotal				$ 64.24	$ 64.24	$ -	0.00%
GRSA	14.19%	14.19%		9.12	9.12	-	
*ESA	-3.35%	-3.35%		(2.15)	(2.15)		
Base Rate Amount				$ 71.21	$ 71.21	$ -	0.00%
DSMCA	$ 0.00241 /kWh	$ 0.00241 /kWh		$ 2.71	$ 2.71	$ -	
PCCA	$ 0.00642 /kWh	$ 0.00642 /kWh		$ 7.21	$ 7.21	$ -	
CACJA	**$ 0.00462 /kWh**	**$ 0.00450 /kWh**		**$ 5.19**	**$ 5.05**	**$ (0.14)**	
TCA	$ 0.00062 **/kWh**	$ 0.00062 **/kWh**		**$ 0.70**	**$ 0.70**	**$ -**	
ECA - Secondary	$ 0.03271 /kWh	$ 0.03271 /kWh		$ 36.73	$ 36.73	$ -	
Subtotal Base Rate Adjustments				$ 52.54	$ 52.40	$ (0.14)	
Total Bill Subtotal				$ 123.75	$ 123.61	$ (0.14)	-0.11%
RESA	2.00%	2.00%		$ 2.48	$ 2.47	$ (0.01)	
Total Bill				$ 126.23	$ 126.08	$ (0.15)	**-0.12%**

Public Service Company of Colorado
Electric Department
Customer Impact Study 2016-2017

Customer Class	Proposed 2016 Rate			Proposed 2017 Rate			Monthly Average Usage		Proposed 2016 Bill		Proposed 2017 Bill		Monthly Difference $		Difference %
Secondary General - Schedule SG															
Service and Facility Charge	$	40.00		$	40.00		51.49%	L.F.	$	40.00	$	40.00	$	-	
Energy Charge	$	0.00473	kWh	$	0.00473	kWh	26,685	kWh		126.22		126.22		-	
Distribution Demand Charge	$	4.84	/kW	$	4.84	/kW	71.00	kW		343.64		343.64		-	
G & T Demand Charge - Annualized	$	8.99	/kW	$	8.99	/kW	71.00	kW		638.29		638.29		-	
Subtotal									$	1,148.15	$	1,148.15	$	-	0.00%
GRSA		14.19%			14.19%					162.92		162.92		-	
*ESA		-3.35%			-3.35%					(38.46)		(38.46)			
Base Rate Amount									$	1,272.61	$	1,272.61	$	-	0.00%
DSMCA	$	0.81	/kW	$	0.81	/kW			$	57.51	$	57.51	$	-	
PCCA	$	2.13	/kW	$	2.13	/kW			$	151.23	$	151.23	$	-	
CACJA	**$**	**1.53**	**/kW**	**$**	**1.49**	**/kW**			**$**	**108.63**	**$**	**105.79**	**$**	**(2.84)**	
TCA	$	0.21	/kW	$	0.21	/kW			$	14.91	$	14.91	$	-	
ECA - Secondary	$	0.03271	/kWh	$	0.03271	/kWh			$	872.87	$	872.87	$	-	
Subtotal Base Rate Adjustments									$	1,205.15	$	1,202.31	$	(2.84)	
Total Bill Subtotal									$	2,477.76	$	2,474.92	$	(2.84)	-0.11%
RESA		2.00%			2.00%				$	49.56	$	49.50	$	(0.06)	
Total Bill									$	2,527.32	$	2,524.42	$	(2.90)	**-0.11%**
Primary General - Schedule PG															
Service and Facility Charge	$	305.00		$	305.00		64.82%	L.F.	$	305.00	$	305.00	$	-	
Energy Charge	$	0.00461	kWh	$	0.00461	kWh	492,079	kWh		2,268.48		2,268.48		-	
Distribution Demand Charge	$	3.98	/kW	$	3.98	/kW	1,040.00	kW		4,139.20		4,139.20		-	
G & T Demand Charge - Annualized	$	8.03	/kW	$	8.03	/kW	1,040.00	kW		8,351.20		8,351.20		-	
Subtotal									$	15,063.88	$	15,063.88	$	-	0.00%
GRSA		14.19%			14.19%					2,137.56		2,137.56		-	
*ESA		-3.35%			-3.35%					(504.64)		(504.64)			
Base Rate Amount									$	16,696.80	$	16,696.80	$	-	0.00%
DSMCA	$	0.75	/kW	$	0.75	/kW			$	780.00	$	780.00	$	-	
PCCA	$	1.98	/kW	$	1.98	/kW			$	2,059.20	$	2,059.20	$	-	
CACJA	**$**	**1.41**	**/kW**	**$**	**1.37**	**/kW**			**$**	**1,466.40**	**$**	**1,424.80**	**$**	**(41.60)**	
TCA	$	0.20	/kW	$	0.20	/kW			$	208.00	$	208.00	$	-	
ECA - Primary On-Peak (1)	$	0.03987	/kWh	$	0.03987	/kWh			$	7,509.44	$	7,509.44	$	-	
ECA - Primary Off-Peak (1)	$	0.02694	/kWh	$	0.02694	/kWh			$	8,182.51	$	8,182.51	$	-	
Subtotal Base Rate Adjustments									$	20,205.55	$	20,163.95	$	(41.60)	
Total Bill Subtotal									$	36,902.35	$	36,860.75	$	(41.60)	-0.11%
RESA		2.00%			2.00%				$	738.05	$	737.22	$	(0.83)	
Total Bill									$	37,640.40	$	37,597.97	$	(42.43)	**-0.11%**

(1) Assumes 38.276% on-peak and 61.724% off-peak usage factors.

Public Service Company of Colorado
Electric Department
Customer Impact Study 2016-2017

Customer Class		Proposed 2016 Rate			Proposed 2017 Rate		Monthly Average Usage			Proposed 2016 Bill		Proposed 2017 Bill		Monthly Difference $	Difference %
Transmission General - Schedule TG															
Service and Facility Charge	$	14,800.00		$	14,800.00		72.68%	L.F.	$	14,800.00	$	14,800.00	$	-	
Energy Charge	$	0.00451	/kWh	$	0.00451	/kWh	12,889,873	kWh		58,133.33		58,133.33		-	
Demand Charge - Annualized	$	7.68	/kW	$	7.68	/kW	24,294	kW		186,577.92		186,577.92		-	
Subtotal									$	259,511.25	$	259,511.25	$	-	0.00%
GRSA		14.19%			14.19%					36,824.65		36,824.65		-	
*ESA		-3.35%			-3.35%					(8,693.63)		(8,693.63)			
Base Rate Amount									$	287,642.27	$	287,642.27	$	-	0.00%
DSMCA	$	0.70	/kW	$	0.70	/kW			$	17,005.80	$	17,005.80	$	-	
PCCA	$	1.84	/kW	$	1.84	/kW			$	44,700.96	$	44,700.96	$	-	
CACJA	**$**	**1.30**	**/kW**	**$**	**1.27**	**/kW**			**$**	**31,582.20**	**$**	**30,853.38**	**$**	**(728.82)**	
TCA	$	0.18	/kW	$	0.18	/kW			$	4,372.92	$	4,372.92	$	-	
ECA - Transmission On-Peak (2)	$	0.03929	/kWh	$	0.03929	/kWh			$	182,942.44	$	182,942.44	$	-	
ECA - Transmission Off-Peak (2)	$	0.02655	/kWh	$	0.02655	/kWh			$	218,603.78	$	218,603.78	$	-	
Subtotal Base Rate Adjustments									$	499,208.10	$	498,479.28	$	(728.82)	
Total Bill Subtotal									$	786,850.37	$	786,121.55	$	(728.82)	-0.09%
RESA		2.00%			2.00%				$	15,737.01	$	15,722.43	$	(14.58)	
Total Bill									$	802,587.38	$	801,843.98	$	(743.40)	**-0.09%**

(2) Assumes 36.123% on-peak and 63.877% off-peak usage factors.

Public Service Company of Colorado
Electric Department
Projected Riders by Class - Settlement

*ECA is 1st Q CPUC Filed Rate, 2nd, 3rd and 4th Q Projection from Annual ECA filing.

Schedule R	*Actual 2015	Proposed 2015
DSMCA	0.00244	0.00244
PCCA	0.00650	0.00650
CACJAR		0.00392
TCA	0.00127	0.00063
ECA Secondary	0.03271	0.03271

Schedule C	*Actual 2015	Proposed 2015
DSMCA	0.00241	0.00241
PCCA	0.00642	0.00642
CACJAR		0.00387
TCA	0.00126	0.00062
ECA Secondary	0.03271	0.03271

Schedule SG	*Actual 2015	Proposed 2015
DSMCA	0.81	0.81
PCCA	2.13	2.13
CACJAR		1.28
TCA	0.42	0.21
ECA Secondary	0.03271	0.03271

Schedule PG	*Actual 2015	Proposed 2015
DSMCA	0.75	0.75
PCCA	1.98	1.98
CACJAR		1.19
TCA	0.40	0.20
ECA On-Peak	0.03987	0.03987
ECA Off Peak	0.02694	0.02694

Schedule TG	*Actual 2015	Proposed 2015
DSMCA	0.70	0.70
PCCA	1.84	1.84
CACJAR		1.11
TCA	0.37	0.18
ECA On-Peak	0.03929	0.03929
ECA Off-Peak	0.02655	0.02655

PUBLIC SERVICE COMPANY OF COLORADO

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Cancels
Sheet No.

ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER

APPLICABILITY

All rate schedules for electric service are subject to a Clean-Air Clean-Jobs Act Rider (CACJA Rider) designed to recover both the capital and operations and maintenance costs associated with Eligible Clean-Air Clean-Jobs Act Projects in accordance with the Settlement Agreement approved by the Commission in Decision No. C15-XXXX in Proceeding No. 14AL-0660E.

The CACJA Rider for all applicable rate schedules is as set forth on Sheet No. 112E. The CACJA Rider shall be calculated for each service schedule and for customers subscribing for Standby Service.

DEFINITIONS

Clean-Air Clean-Jobs Act (CACJA)
House Bill HB10-1365 required Public Service to work with the Colorado Department of Public Health and Environment to submit a plan to the Public Utilities Commission to reduce nitrogen oxide emissions at Front Range coal plants by 70 to 80 percent by December 31, 2017. The plan, which was approved by the Commission in 2010, includes the retirement of five aging coal plants, their replacement with a new natural gas combined cycle plant, the addition of pollution control equipment at three other coal plants, and the conversion of one coal plant to a natural gas fuel source.

Eligible CACJA Projects
The approved projects included in this CACJA Rider are as follows:

1. Cherokee 5, 6, and 7 -- a natural gas combined cycle (CC) plant, including interconnection equipment.
2. Pawnee selective catalytic reduction and particulate scrubber.
3. Hayden 1 selective catalytic reduction.
4. Hayden 2 selective catalytic reduction.

Eligibility Window: To be eligible to be included in the Rider a cost must be incurred and associated with an investment that went into service between August 1, 2014 and December 31, 2017.

CACJA Revenue Requirement
The forecasted or actual costs associated with Eligible CACJA Projects, including the following:

1. Variable non-fuel Operation and Maintenance (O&M) expenses, including chemical and water expenses. The 2015 CACJA Base Costs will include the variable non-fuel O&M for the existing Cherokee 3 coal unit. After that unit is retired at the end of 2015, subsequent CACJA rider calculations will reflect the variable O&M savings from Cherokee 3's retirement.

(Continued on Sheet No. 112A)

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ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER

DEFINITIONS – Cont'd

CACJA Revenue Requirement – Cont'd

2. Depreciation expense, which will be calculated monthly.
3. State and federal current and deferred income tax expense. This income tax expense shall recognize the impacts of depreciation expense and any other tax deductions including the Domestic production Activities Tax Deduction – Section 199.
4. Return on net plant for projects that have been placed into service, including the accumulated allowance for funds used during construction (AFUDC) for capital expenditures incurred before January 1, 2015.
5. Return on construction work in progress (CWIP) for capital expenditures incurred on or after January 1, 2015.

CACJA Forecasted Revenue Requirements (FRR)

Forecast of the CACJA Revenue Requirement for the subsequent calendar year, based on the best available estimates of capital expenditures, O&M expenses, taxes, and the cost of capital.

CACJA Actual Revenue Requirements (ARR)

The actual CACJA Revenue Requirement for the previous calendar year.

CACJA Rider Revenues (RR)

The actual amount collected from customers in a given year through the CACJA Rider.

Allowance for Funds Used During Construction (AFUDC)

An account that tracks the accumulating costs to the Company to fund large construction projects. The account includes the financing cost of the capital invested in the construction project. These costs are tracked until the project is placed into service, at which point the accumulated AFUDC is included as part of the gross plant placed in service.

Construction Work In Progress (CWIP)

The capital expenditures the Company incurs for a project prior to its in-service date.

Return on CWIP

The Return on CWIP will be the Company's weighted average cost of capital (WACC) times the average monthly CWIP balance for the relevant period.

(Continued on Sheet No. 112B)

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ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER

DEFINITIONS – Cont'd

Weighted Average Cost of Capital (WACC)
The costs of debt and common equity weighted by the relative proportions of each in the Company's balance sheet. For the purpose of developing the FRR, a forecast of the debt cost and capital structure for the following calendar year will be used. For the purpose of developing both the FRR and ARR, the return on equity shall be the latest return on equity approved by the Commission for the Company's electric department.

CACJA Rider True-up
The over-recovery or under-recovery of CACJA costs from two years previous. In 2015 and 2016 the CACJA Rider True-up value shall be $0. The CACJA Rider True-up consists of three components. The first is an adjustment that reconciles the difference between the forecasted revenue requirements (FRR) and the prudently incurred actual revenue requirements (ARR) from two years prior that are demonstrably tied to specific CACJA projects for which the Company has a CPCN. The second component accounts for the difference between the revenues the rider was designed to recover from customers and the actual dollars collected. The third component is an adjustment for interest expenses on the monthly over- or under-recovery from two years prior. For each month the interest component shall be the after-tax WACC applied to the monthly over- or under-collection from the mid-point of the month to the date on which the Company will begin crediting or collecting the over- or under-collection through the CACJA Rider True-up.

CLEAN AIR CLEAN JOBS ACT RIDER AMOUNT

The CACJA Rider Amount shall consist of the current year's Forecasted Revenue Requirement plus the CACJA Rider True-up.

The following formula is used to determine the total annual costs to be collected through the CACJA Rider.

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ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER

CLEAN AIR CLEAN JOBS ACT RIDER AMOUNT – Cont'd

CACJA Rider = Forecasted Rev.Req. + True-up1 + True-up$_2$ + True-up$_3$
= $FFR_y + (ARR_{y-2} - FRR_{y-2}) + (FRR_{y-2} - RR_{y-2}) + Int_{y-2}$

FRR_y = Forecasted CACJA revenue requirements in year 'y', the current year
FRR_{y-2} = Forecasted CACJA revenue requirements in year 'y-2', two years previous
ARR_{y-2} = Actual revenue requirements for CACAJA projects in year 'y-2', two years previous
RR_{y-2} = Actual revenues collected through the CACJA Rider in year 'y-2', two years previous
Int_{y-2} = Accumulated interest expense in year 'y-2', two years previous. Interest shall be calculated monthly by applying the Company's after-tax WACC applied to each months average over or under recovered balance.

The FRR used to set 2015 rates will be $96,968,401.

The True-up component of the 2017 rates will be based on the ARR for the entire year of 2015.

RATE DESIGN

The costs of approved Clean-Air Clean-Job initiatives will be allocated to rate classes based on the production demand allocator approved in the Company's latest Phase II rate case. The allocation factors will be updated based on a projection of energy use by customer class for the forecast year. Rates shall be designed by dividing the costs allocated to each class by the projected class billing determinants. The rates for all years will be based on 12 months of projected class billing determinants. Residential Demand, Secondary General, Primary General, Transmission General, Special Contracts and Standby customers shall be billed the CACJA Rider on a demand basis; all other customers will be billed on an energy basis.

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Cancels
Sheet No.

ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER

INFORMATION TO BE FILED WITH THE PUBLIC UTILITIES COMMISSION

Each revision to the CACJA Rider will be accomplished by filing an advice letter no later than November 1st of each year to take effect on the next January 1 and will be accompanied by such supporting data and information as the Commission may require.

The Company shall submit an additional annual filing on or around April 15, 2016, April 15, 2017 and April 15, 2018. In this filing the Company will: discuss the types and levels of expenditures incurred for Eligible CACJA Projects during the previous calendar year; and compare the FRR and ARR for the previous calendar year and explain material deviations. At a minimum, the Company will include in its filing the materials and data consistent with the Settlement reached in Proceeding No. 14AL-0660E.

(Continued on Sheet No. 112E)

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Sheet No. 112E

Cancels
Sheet No.

ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER

RATE TABLE

Rate Schedule	Applicable Charge	Monthly Rider Rate
Residential Service		
R, RTOU, RPTR, RCPP	Energy Charge	$0.00392/kWh
RD	Demand Charge	0.42/kW-Mo
Small Commercial Service		
C	Energy Charge	0.00387/kWh
NMTR	Energy Charge	0.00387/kWh
Commercial & Industrial General Service		
SGL	Energy Charge	0.01605/kWh
SG, STOU, SPVTOU	Demand Charge	1.28/kW-Mo
PG, PTOU	Demand Charge	1.19/kW-Mo
TG, TTOU	Demand Charge	1.11/kW-Mo
Special Contract Service		
SCS-7	Production Demand Charge	1.19/kW-Mo
Standby Service		
SST	Gen & Trans Standby Capacity Reservation Fee	0.15/kW-Mo
	Usage Demand Charge	1.13/kW-Mo
PST	Gen & Trans Standby Capacity Reservation Fee	0.14/kW-Mo
	Usage Demand Charge	1.05/kW-Mo
TST	Gen & Trans Standby Capacity Reservation Fee	0.13/kW-Mo
	Usage Demand Charge	0.98/kW-Mo
Lighting Service		
RAL, CAL, PLL, MSL, ESL, SL, SSL, COL, SLU	Energy Charge	0.00192/kWh
TSL, MI	Energy Charge	0.00192/kWh

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COLO. PUC No. 7 Electric

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 109

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Cancels
Sheet No.

ELECTRIC RATES
TRANSMISSION COST ADJUSTMENT

APPLICABILITY

All rate schedules for electric service are subject to a Transmission Cost Adjustment ("TCA") rider to reflect the ongoing capital costs associated with transmission investment that are not being recovered through the Company's base rates. The TCA amount will be subject to annual changes to be effective on January 1 of each year. The TCA to be applied to each rate schedule is as set forth on Sheet No. 109B.

DEFINITIONS

Over/Under Recovery Amount – The Over/Under Recovery Amount is the balance, positive or negative, of TCA revenues received less the Transmission Cost intended to be recovered each year through the rider.

True-Up Amount – The True-Up Amount is equal to the difference, positive or negative, between the Transmission Cost, calculated based on the projected ~~year end~~ net transmission plant and transmission CWIP balances, and the Transmission Cost calculated based on the actual ~~year-end~~ net transmission plant and transmission CWIP balances.

If any projects included in the year-end CWIP balance were placed in service sometime during the subsequent year when the TCA was effective, then the CWIP balance will be reduced accordingly. Specifically, the component of the year-end CWIP balance attributable to any such project will be reduced by the following:

Year-End Project CWIP Balance X (Number of Months Project Was in Service During Subsequent Year / 13)

Transmission Cost – For the purpose of this tariff, the Transmission Cost is defined as (1) a return, equal to the Company's weighted average cost of capital, on the projected increase in the retail jurisdictional portion of the thirteen month average net transmission plant for the ~~thirteen months immediately preceding the~~ year in which the TCA will be in effect; (2) the plant-related ownership costs associated with such incremental transmission investment, including depreciation, accumulated deferred income taxes, income taxes and pre-funded AFUDC, and (3) a return, equal to the Company's weighted average cost of capital, on the projected year-end transmission construction work in progress ("CWIP") balance as of December 31 of the year immediately preceding the effective date of the TCA. ~~that is not being recovered through base rates.~~

(Continued on Sheet No. 109A)

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Sheet No.

ELECTRIC RATES
TRANSMISSION COST ADJUSTMENT

DEFINITIONS – Cont'd

If any projects included in the year-end CWIP balance are projected to be placed in service sometime during the subsequent year when the TCA will be effective, then the CWIP balance will be reduced accordingly. Specifically, the component of the year-end CWIP balance attributable to any such project will be reduced by the following:

Year-End Project CWIP Balance X (Number of Months Project Will Be in Service During Subsequent Year / 13)

Transmission Cost Adjustment - The Transmission Cost Adjustment is equal to the Transmission Cost, plus, beginning with the second year of the rider, the True-Up Amount and, beginning with the third year of the rider, the Over/Under Recovery Amount, charged on a dollar per kilowatt basis for tariff schedules with demand rates and on a dollar per kilowatt-hour basis for tariff schedules without demand rates.

INFORMATION TO BE FILED WITH THE PUBLIC UTILITIES COMMISSION

Each proposed revision in the Transmission Cost Adjustment will be accomplished by filing an advice letter on November 1 of each year to take effect on the next January 1 and will be accompanied by supporting data and information as set forth in Ordering Paragraph No. 6 of Decision No. C07-1085.

TCA ADJUSTMENT WITH CHANGES IN BASE RATES

Whenever 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.

INTEREST CALCULATION UNDER A TRUE UP

Over collections of rider revenues that are due to over projections of net plant and CWIP balances shall be assessed interest as part of the true-up mechanism in the TCA. To determine an over collection of rider revenues due to over projections of net plant and CWIP, the revenue requirements associated with the projected net plant in service and CWIP shall be compared to the revenue requirements associated with the actual net plant in service and CWIP for that same year. Interest is only assessed on the positive balance of rider revenues calculated on projected plant in service and CWIP compared to the calculated rider revenues based on actual plant in service and CWIP over the same time period. Interest shall be calculated at the after taxes weighted average cost of capital.

(Continued on Sheet No. 109B)

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Sheet No. 109B

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Cancels
Sheet No.

ELECTRIC RATES
TRANSMISSION COST ADJUSTMENT

RATE TABLE

Rate Schedule	Applicable Charge	Monthly Rider Rate
Residential Service		
R, RTOU, RPTR, RCPP	Energy Charge	$0.00063~~127~~/kWh
RD	Demand Charge	$ 0.07~~14~~ /kW-Mo
Small Commercial Service		
C	Energy Charge	$ 0.00062~~126~~ /kWh
NMTR	Energy Charge	$ 0.00062~~126~~ /kWh
Commercial & Industrial General Service		
SGL	Energy Charge	$ 0.00258~~524~~ /kWh
SG, STOU, SPVTOU	Demand Charge	$ 0.21~~42~~ /kW-Mo
PG, PTOU	Demand Charge	$ 0.20~~40~~ /kW-Mo
TG, TTOU	Demand Charge	$ 0.18~~37~~ /kW-Mo
Special Contract Service		
SCS-7	Production Demand Charge	$ 0.20~~40~~ /kW-Mo
Standby Service		
SST	Gen & Trans Standby Capacity Reservation Fee	$ 0.02~~05~~ /kW-Mo
	Usage Demand Charge	$ 0.19~~37~~ /kW-Mo
PST	Gen & Trans Standby Capacity Reservation Fee	$ 0.02~~05~~ /kW-Mo
	Usage Demand Charge	$ 0.18~~35~~ /kW-Mo
TST	Gen & Trans Standby Capacity Reservation Fee	$ 0.02~~05~~ /kW-Mo
	Usage Demand Charge	$ 0.16~~33~~ /kW-Mo
Lighting Service		
RAL, CAL, PLL, MSL, ESL, SL, SSL, COL, SLU	Energy Charge	$ 0.00032~~65~~/kWh
TSL, MI	Energy Charge	$ 0.00032~~65~~/kWh

ADVICE LETTER NUMBER

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EFFECTIVE DATE

Public Service Company of Colorado
Proceeding No. 14AL-0660E

Earnings Test Sharing Mechanism
Calculation Methodologies and Adjustments
for 2015 – 2017 Calendar Year Reports

RATE BASE

1. Rate Base will be calculated using year-end plant balances except for Cash Working Capital, the coal, oil and natural gas used for electric generation inventory balances.

2. Coal, oil and natural gas used for electric generation inventory will be calculated using the average of the 12 monthly average balances during the calendar year.

3. Materials and supplies inventory and other non-plant rate base items, such as customer deposits will be calculated using a thirteen-month average of month-end balances.

4. The Accumulated Deferred Income Tax ("ADIT") balances are calculated using year-end balances and will incorporate the effects of bonus depreciation as applicable.

5. The ADIT reserve is a reduction to rate base, as opposed to a cost-free component in the capital structure. The ADIT balances will be functionalized. Adjustments to ADIT include eliminating amounts that are not included in the cost of service calculation and including adjustments related to plant adjustments.

6. The Company will calculate its earnings for purposes of the Earnings Test, using full tax normalization, allowing the Company to provide for deferred taxes on all book/tax timing differences, including any offset to ADIT for net operating losses ("NOL") or NOL carry forward applicable to the Company's electric department for income tax purposes.

7. Adjustments to rate base and specific assignment of plant to either CPUC or FERC jurisdictions will be made using the year-end plant balances.

8. An adjustment is made to eliminate from Construction Work in Progress and Plant in Service costs otherwise reflected in the CACJA rider.

9. Construction Work In Progress ("CWIP") will be included in rate base with an Allowance for Funds Used During Construction ("AFUDC") addition to earnings based on the year-end balance. The Company will annualize the AFUDC addition to earnings.

10. Pre-Funded AFUDC associated with the Comanche project and the transmission assets recovered through the Transmission Costs Adjustment ("TCA") that is included the plant in-service balances, is included as a reduction to rate base.

11. Eliminate contractor retentions from CWIP.

12. Adjustments to any rate base item for changes after the end of the calendar year being reviewed are not included.

13. Intangible plant in service will be functionalized in order to properly allocate to the retail jurisdiction.

14. Common plant is allocated to the electric, gas, thermal energy and non-regulated departments based on an annual study of all common plant assets and assigning an allocation method for each type of asset. A copy of the common plant study will be included with the earnings test sharing mechanism report when the report is filed with the Commission.

15. An adjustment is made to eliminate from plant in service fifty percent of the investment in specific distribution substations serving Holy Cross Rural Electric Association ("HCE").

16. An adjustment is made to eliminate from plant in service the amount of cost associated with the Pawnee turbine blade project that exceeded the Commission-ordered expenditure cap.

17. An adjustment is made to eliminate from plant in service the costs associated with the Ponnequinn wind assets.

18. Capital lease assets are not included in rate base.

19. The acquisition premium associated with the acquisition of the Calpine assets, is recorded in the following FERC Accounts and will be included in the Earnings Test calculation: Account 114 – Acquisition Adjustment, Account 115 – Accumulated Amortization of Acquisition Adjustment, and Account 407- Amortization of Acquisition Adjustment.

20. Southeast Water Rights recorded in Plant Held for Future Use ("PHFU") without amortization, and will continue to be included in rate base at a debt-only return.

21. The amounts recorded in PHFU associated with ash disposal site in Bennett, Colorado (known as "Metro Ash Disposal site") are excluded from rate base. In the event the Company sells this property in the future, any proceeds or losses incurred will be retained by the Company and excluded from the earning sharing calculation.

22. Regulatory assets will be included in rate base that are associated with the early plant retirements and cost of removal of Cameo units 1 and 2; Arapahoe units 3 and 4; and Cherokee 1 and 2. The amortization of these regulatory assets will continue to be based on the depreciation rates approved in Proceeding No. 11AL-947E.

23. An adjustment is made to eliminate a portion of the materials and supplies inventory balance allocated to construction-related projects.

24. Cash working capital components consist of fuel costs, purchased power costs, operation and maintenance expenses ("O&M expense"), both directly incurred by the Company and charges from Xcel Energy Services, Inc., paid time off, taxes other than income (payroll taxes, property taxes, sales and use taxes), federal and state income taxes and franchise fees and sales taxes paid. The cash working capital factors used shall be based on the lead-lag study presented in Proceeding No. 14AL-0660E in Attachment No. DAB-10.

25. The Legacy Pre-Paid Pension Asset balance will be incorporated into the Earnings Test as described in Section *I.*C.6(i) of the Settlement Agreement. The Legacy Pre-Paid Pension Asset and related accumulated deferred income tax balance that is included in rate base for purposes of the earnings test shall be equal to the unamortized balances of the Legacy Pre-Paid Pension Asset and the associated ADIT as of the end of the year to which the earnings test applies.

26. The New Pre-Paid Pension Asset balance, as defined in Section *I.*C.6(ii) of the Settlement Agreement shall be excluded from the Earnings Test calculation. Except to the extent the New Pre-Paid Pension Asset becomes reflected in the GRSA as described in Section *I.*H.2 of the Settlement Agreement.

27. Deductions from rate base include customer deposits, Qualifying Facilities ("QF") deposits (net of accrued interest), and customer advances for construction.

28. The unamortized balance of the regulatory liability associated with the gain on the sale of rail cars will not be included in rate base.

29. The retiree medical liability FAS 106 balance will be included in rate base.

<u>REVENUES</u>

30. Retail Base Rate Revenue does not include revenues billed through the following rider and fuel recovery mechanisms: ECA, PCCA, DSMCA, ISOC, CACJA, ESA, and RESA. Any costs or incentives associated with these recovery mechanisms are eliminated from the Earnings Test calculation and the supporting adjustment will be disclosed in the earnings test report. Unbilled revenues are not included in the Earnings Test calculation.

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

32. No adjustments are included to account for customer additions or losses to the calendar year sales or base rate revenues.

33. Electric sales will be normalized for weather. The weather normalization method will be based on the methodology filed in Proceeding No. 11AL-947E. The Company will reflect a weather normalization adjustment equal to 50% of the value of weather normalized for demand and 100% of value weather normalized sales. A description of the weather normalization methodologies applied to sales and demand is provided in Exhibit 1 to Attachment E.

34. Adjustments will be made to Miscellaneous Revenue to eliminate the rate refunds, Quality of Service Plan bill credits, DSM incentives, Joint Operating Agreement revenue, wholesale related transmission and ancillary service revenues, unbilled transmission revenues, ISOC, deferred fuel revenues, Hybrid Renewable Energy Credits, and discounts given to certain contract customers under §40-3-104.3(2)(a).

35. The earnings test calculation will include a revenue credit equal to 50% of the oil and gas royalty revenues recorded as non-utility revenue. As included in the Settlement Agreement in Section *II.*C.3.

36. Residential late payment revenues will be excluded from the cost of service calculation. The Company will continue to donate the residential late payment revenues to Energy Outreach Colorado, and will exclude the donation from the Earnings Test calculation.

EXPENSES

37. Fuel expenses, purchased power energy expenses and purchased wheeling expenses recovered through the fuel and purchased power recovery mechanisms are eliminated from the determination of revenue requirements.

38. The earnings test calculation will eliminate amounts that are booked in calendar years 2015, 2016 or 2017 that are applicable to periods prior to 2012. These adjustments are known as out-of-period accounting entries.

39. An adjustment is made to eliminate O&M expenses otherwise reflected in the CACJA rider from the Earnings Test calculation.

40. The earnings test calculation will eliminate all O&M associated with incremental wholesale sales.

41. The earnings test calculation will eliminate the margins associated with the Company's trading activities that are returned to customers through the ECA mechanism.

42. Eliminate 50% of the expenses associated with the Company's trading activities as set forth in 2nd Revised Attachment No. DAB-3, Schedule 52 filed in Proceeding No. 14AL-0660E.

43. Interest on QF deposits is included in Production O&M.

44. The Calpine acquisition costs will be amortized over ten (10) years beginning in December 2010, and will be included in the Earnings Test calculation.

45. The Legacy Pre-Paid Pension Asset balance net of the associated ADIT will be amortized over a period of 15 years beginning on the date on which rates are effective as a result of a final Commission order in Proceeding No. 14AL-0660E, resulting in a net annual amortization expense equal to $9,275,830 which amount shall be included in the Earnings Test. Any amortization of the New Pre-Paid Pension Asset balance net of the ADIT which becomes reflected in the GRSA as described in Section *I.*H.2 of the Settlement Agreement shall also be included in the Earnings Test calculation.

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

47. Lease expense associated with the Dark Fiber assets is included in the Earnings Test calculation.

48. Demand Side Management ("DSM") costs are included in base rates at the level of $89,263,631 as set in Proceeding No. 09AL-299E.

49. Advertising expense related to specific energy conservation, safety, and customer programs and services are included in the Earnings Test calculation.

50. Advertising expense related to marketing, promotion, community relations, image and political ads are eliminated.

51. All lobbying expenses and donations are excluded from the Earnings Test calculation.

52. Executive long-term incentive pay, other than the portion attributable to environmental goals, is excluded in the Earnings Test calculation.

53. Discretionary pay is not included in the Earnings Test calculation.

54. Any amounts paid to employees for their Annual Incentive Pay ("AIP") above a 15% cap, as described in the Settlement Agreement in Section *II.*C.1, shall be excluded from the Earnings Test calculation.

55. Employee expenses that do not meet corporate guidelines will not be included in the Earnings Test calculation. The amounts and accounts used of these expenses will be provided in a report in the Earnings Test.

56. Regulatory commission expenses associated with the Commission fees as booked in the calendar year will be included in the Earnings Test calculation without adjustment.

57. For the purposes of the Earnings Test Calculation, rate case expenses of $1,700,000 will be amortized over a three year period (2015 through 2017) as referenced in the Settlement Agreement in Section *I*.G.

58. Aviation expenses associated with the corporate aircraft will be excluded from the Earnings Test calculation.

59. Cost allocation between regulated and non-regulated business activities is based on the Cost Allocation Manual and the Fully Distributed Cost Allocation Study filed in Proceeding No. 14AL-0660E. The Company will identify and provide the basis for any changes to cost allocation methodologies with the annual Earnings Test filing.

60. Depreciation expense is based on the currently effective depreciation rates provided in Exhibit 2 to Attachment E.

61. The Mountain Pine Beetle amortization expense as described pursuant to the Settlement Agreement in Section *I*.G shall be included in the Earnings Test calculation.

62. Adjustments to depreciation and amortization expense are made to correspond with adjustments made to plant and accumulated depreciation, or to exclude amounts not included in the Earnings Test calculation.

63. The retail property tax expense will be equal to $109,506,702 annually for the Earnings Test calculations for calendar years 2015, 2016 and 2017. In addition property taxes deferred in 2012, 2013 and 2014 will be amortized consistent with the provisions of the Settlement Agreement entered into in Proceeding No. 11AL-947E but will be included in the earnings test calculation in the amount of $27,827,992. Beginning January 1, 2015, the difference between the actual property tax expense incurred each year and $109,506,702 and between the actual property tax amortization and $27,827,992 will be deferred and accounted for as a regulatory asset or liability which asset or liability will be amortized over a period of three years beginning no earlier than January 1, 2018 and included in the cost of service filed in the 2017 rate case.

64. The retail electric qualified pension expense will be equal to $21,086,171 and the retail electric non-qualified pension expense will be equal to $883,950. Pension expenses above or below the above-stated amounts of qualified and non-qualified pension expense will be deferred beginning January 1, 2015 and accounted for as a regulatory asset or liability. Such deferred amounts will be excluded from the earnings test.

65. Adjustments to payroll taxes are made to correspond to labor adjustments made to O&M expense, e.g., trading O&M costs, aviation expenses, executive long-term incentive costs.

66. Current federal and state income taxes are calculated as follows: taxable income is derived by starting with revenue less expenses and then synchronized interest expense is deducted and taxable additions/deductions are added, then stated and federal income taxes are applied.

67. Adjustments to current and deferred income tax expense are made to correspond with adjustments made to plant or to exclude amounts not included in the Earnings Test calculation.

68. Income tax expenses are reduced for the Manufacturing Production Tax deduction.

69. Gain on the disposition of emission credits (SO_2 allowances) due to the Department of Energy auction is included as a credit to the Earnings Test calculation.

70. Gain on the sale of steel railcars, net of actual one-time 2006 costs, are amortized over ten (10) years beginning January 1, 2007. There will be no amortization associated with the gain on the sale of steel railcars included in the 2017 earnings test.

CAPITAL STRUCTURE

71. The capital structure ratio will be based on year-end actual balances, subject to a cap of 56% equity. Adjustments are made to the capital structure to eliminate the following items: 1) notes payable/receivable with subsidiaries; 2) investment in subsidiaries; 3) subsidiary retained earnings; 4) net non-utility plant; 5) other investments at cost; 6) other funds; and 7) other comprehensive income.

72. Cost of Debt is the actual cost as of the end of the year calculated using the par value method, and includes bond premiums or discounts, underwriting expenses, other expenses of issue, and amortization of the long-term credit facility.

73. The return on equity for measuring any sharing under the Earnings Test calculation is 9.83%. If the Company earns in excess of a 9.83%, earnings will be shared with customers using the following structure:

Earned Return on Equity	Sharing Percentages	
	Customers	Company
≤ 9.83%	0%	100%
> 9.83% ≤ 10.48%	50%	50%
> 10.48%	100%	0%

JURISDICTIONAL ALLOCATION FACTORS AND DIRECT ASSIGNMENTS

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

75. Direct assignment of any costs of service item to either retail or the wholesale jurisdiction is identified, consistent with the Company's 2nd Revised Attachment No. DAB-3 in Proceeding No. 14AL-0660E.

76. Rent expense in FERC Account 923 will be analyzed to determine direct assignments to retail or allocated to retail based on labor.

77. The earnings test calculations will directly assign EEI dues and EPRI to retail jurisdiction.

Public Service Company of Colorado
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Sales Weather Normalization Methodology –

Public Service Company of Colorado weather normalizes sales for the Residential service, Commercial service, Secondary General service, and Primary General service classes.

Degree –day data is used to estimate the amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature. Heating degree days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65 degrees Fahrenheit, and cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above the 65 degrees Fahrenheit. Each degree of temperature above 65 degrees Fahrenheit is counted as one CDD, and each degree of temperature below 65 degrees Fahrenheit is counted as one HDD.

Normal weather conditions are defined as the 30-year average of actual historical weather as measured at the NOAA's Denver International Airport (DIA) weather station. The 30-year average is recalculated each year, rolling in the most recent historical year's data and dropping of the earliest year's data.

The percentage increases (decreases) in normal and actual HDD and CDD are as follows for DIA reported weather:

	2011 vs. Normal	2010 vs. Normal	2011 vs. 2010
HDD	1.0%	-3.9%	5.1%
CDD	29.7%	17.1%	10.8%

Demand Weather Normalization Methodology –

The Company has made an adjustment to weather normalize billing demands for the Residential service, Commercial service, Secondary General service, and Primary General service classes in the earnings test. The Company adjusted billing demands for weather variances from normal weather based on weather normalized sales and a Calculated Demand Factor. The Calculated Demand Factor quantifies the relationship of billing demand to sales for a given month by service class, and is calculated as the ratio of billing demand to sales as follows:

Calculated Demand Factor = Billing Demand (KW) / Sales (KWh)

The Calculated Demand Factor is then applied to the respective month's weather normalized sales, resulting in a weather normalized billing demand estimate.

*Weather Normalized Billing Demand = Calculated Demand Factor * Weather Normalized Sales*

The weather normal sales and weather normal billing demands are then used to calculate weather adjusted revenues.

Public Service Company of Colorado
Electric and Common Depreciation Rates
Proceeding No. 14AL-0660E

			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
	ELECTRIC INTANGIBLE PLANT				
301.00	Organization Costs				
302.00	Franchises & Consents	(6)	0.0000%		0.0000%
303.00	Miscellaneous Plant		0.0000%		0.0000%
303.40	Misc Computer Software 5 Yr		20.0000%		20.0000%
303.40	Misc Computer Software 10 Yr		10.0000%		10.0000%
	Total Electric Intangible Plant				
	STEAM PRODUCTION PLANT				
310.10	Land				
310.20	Land Rights		2.0000%		2.0000%
310.30	Water Rights		2.0000%		2.0000%
	Total Account 310				
311.00	Structures & Improvements				
	Arapahoe Unit 3		2.1006%	0.1744%	2.2750%
	Arapahoe Unit 4		2.4164%	0.2006%	2.6170%
	Arapahoe Common		3.3102%	0.2748%	3.5850%
	Cherokee Unit 2 SC		2.0878%	0.1942%	2.2820%
	Cherokee Unit 3		1.7502%	0.1628%	1.9130%
	Cherokee Unit 4		1.8240%	0.2330%	2.0570%
	Cherokee Common		2.3050%	0.2480%	2.5530%
	Comanche Unit 1		1.6360%	0.1970%	1.8330%
	Comanche Unit 2		1.3710%	0.1650%	1.5360%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.5000%	0.1780%	1.6780%
	Craig Unit 1		1.4600%	0.0880%	1.5480%
	Craig Unit 2		1.4380%	0.0870%	1.5250%
	Craig Common		1.4870%	0.0890%	1.5760%
	Hayden Unit 1		1.6759%	0.1961%	1.8720%
	Hayden Unit 2		1.3310%	0.1950%	1.5260%
	Hayden Common		2.2160%	0.2900%	2.5060%
	Pawnee Unit 1		1.4840%	0.0900%	1.5740%
	Pawnee Common		2.7150%	0.1440%	2.8590%
	Valmont Unit 5		2.3783%	0.1807%	2.5590%
	Valmont Common		2.6617%	0.2023%	2.8640%
	Zuni Unit 2	(2)	0.0000%	0.0000%	0.0000%
	Zuni Common		2.4184%	0.3216%	2.7400%
	Total Account 311				
312.00	Boiler Plant Equipment				
	Arapahoe Unit 3		2.7793%	0.2307%	3.0100%
	Arapahoe Unit 4		3.1440%	0.2610%	3.4050%
	Arapahoe Common		5.2419%	0.4351%	5.6770%
	Cherokee Unit 2 SC		2.7722%	0.2578%	3.0300%
	Cherokee Unit 3		2.4273%	0.2257%	2.6530%
	Cherokee Unit 4		1.6920%	0.2220%	1.9140%
	Cherokee Common		2.7650%	0.2910%	3.0560%
	Comanche Unit 1		1.9460%	0.2270%	2.1730%
	Comanche Unit 2		1.8040%	0.2080%	2.0120%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.6290%	0.1920%	1.8210%
	Craig Unit 1		1.5570%	0.1060%	1.6630%
	Craig Unit 2		1.5470%	0.1060%	1.6530%
	Craig Common		2.2670%	0.1440%	2.4110%
	Hayden Unit 1		2.9517%	0.3453%	3.2970%
	Hayden Unit 2		1.7300%	0.2370%	1.9670%
	Hayden Common		2.5300%	0.3190%	2.8490%
	Pawnee Unit 1		1.6670%	0.1130%	1.7800%
	Pawnee Common		2.8790%	0.1750%	3.0540%
	Valmont Unit 5		2.5920%	0.1970%	2.7890%
	Valmont Common		3.6357%	0.2763%	3.9120%
	Zuni Unit 2		2.3901%	0.3179%	2.7080%
	Zuni Common		3.0229%	0.4021%	3.4250%
	Total Account 312.0				

Public Service Company of Colorado
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			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
312.10	AQIR Equipment				
	Arapahoe Unit 3		6.6667%	0.0000%	6.6667%
	Cherokee Unit 3		6.6667%	0.0000%	6.6667%
	Cherokee Unit 4		6.6667%	0.0000%	6.6667%
	Cherokee Common		6.6667%	0.0000%	6.6667%
	Valmont Unit 5		6.6667%	0.0000%	6.6667%
	Total Account 312.1				
312.20	Coal Cars		3.1667%	0.0000%	3.1667%
	Total Account 312				
314.00	Turbogenerator Units				
	Arapahoe Unit 3		2.3850%	0.1980%	2.5830%
	Arapahoe Unit 4		2.7368%	0.2272%	2.9640%
	Arapahoe Common		4.0277%	0.3343%	4.3620%
	Cherokee Unit 2 SC		2.1116%	0.1964%	2.3080%
	Cherokee Unit 3		2.1985%	0.2045%	2.4030%
	Cherokee Unit 4		1.7190%	0.2240%	1.9430%
	Cherokee Common		4.6390%	0.4350%	5.0740%
	Comanche Unit 1		1.6980%	0.2040%	1.9020%
	Comanche Unit 2		1.6350%	0.1920%	1.8270%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		2.3140%	0.2520%	2.5660%
	Craig Unit 1		2.6570%	0.1590%	2.8160%
	Craig Unit 2		1.5140%	0.1010%	1.6150%
	Craig Common		1.5560%	0.1030%	1.6590%
	Hayden Unit 1		2.0627%	0.2413%	2.3040%
	Hayden Unit 2		1.4760%	0.2090%	1.6850%
	Hayden Common		2.7010%	0.3350%	3.0360%
	Pawnee Unit 1		1.5970%	0.1060%	1.7030%
	Pawnee Common		2.2750%	0.1420%	2.4170%
	Valmont Unit 5		3.4591%	0.2629%	3.7220%
	Valmont Common		4.1403%	0.3147%	4.4550%
	Zuni Unit 2		14.6920%	1.9540%	16.6460%
	Zuni Common		1.8464%	0.2456%	2.0920%
	Total Account 314				
315.00	Accessory Electric Equipment				
	Arapahoe Unit 3		4.3019%	0.3571%	4.6590%
	Arapahoe Unit 4		2.4811%	0.2059%	2.6870%
	Arapahoe Common		3.0849%	0.2561%	3.3410%
	Cherokee Unit 2 SC		3.0393%	0.2827%	3.3220%
	Cherokee Unit 3		2.2617%	0.2103%	2.4720%
	Cherokee Unit 4		1.5800%	0.2000%	1.7800%
	Cherokee Common		1.9540%	0.2050%	2.1590%
	Comanche Unit 1		1.5310%	0.1760%	1.7070%
	Comanche Unit 2		1.6290%	0.1790%	1.8080%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.6650%	0.1820%	1.8470%
	Craig Unit 1		1.5290%	0.0860%	1.6150%
	Craig Unit 2		1.4990%	0.0850%	1.5840%
	Craig Common		1.5410%	0.0870%	1.6280%
	Hayden Unit 1		1.9391%	0.2269%	2.1660%
	Hayden Unit 2		1.3750%	0.1870%	1.5620%
	Hayden Common		2.4740%	0.2960%	2.7700%
	Pawnee Unit 1		1.5620%	0.0880%	1.6500%
	Pawnee Common		2.1720%	0.1160%	2.2880%
	Valmont Unit 5		2.3950%	0.1820%	2.5770%
	Valmont Common		2.5678%	0.1952%	2.7630%
	Zuni Unit 2		2.6134%	0.3476%	2.9610%
	Zuni Common		2.2586%	0.3004%	2.5590%
	Total Account 315				

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			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
315.20	Computers & Peripherals (Boiler Controls)				
	Arapahoe Unit 4		6.5088%	0.5402%	7.0490%
	Arapahoe Common		5.1099%	0.4241%	5.5340%
	Cherokee Unit 3		3.8545%	0.3585%	4.2130%
	Cherokee Unit 4		4.3147%	0.4013%	4.7160%
	Cherokee Common		3.1757%	0.2953%	3.4710%
	Comanche Unit 1		3.6712%	0.3488%	4.0200%
	Comanche Common		3.4484%	0.3276%	3.7760%
	Craig Common		2.8817%	0.1383%	3.0200%
	Hayden Unit 1		3.6598%	0.4282%	4.0880%
	Hayden Unit 2		3.4324%	0.4016%	3.8340%
	Pawnee Unit 1		2.9428%	0.1442%	3.0870%
	Pawnee Common		2.6463%	0.1297%	2.7760%
	Valmont Common		3.3690%	0.2560%	3.6250%
	Zuni Common		6.7582%	0.8988%	7.6570%
	Total Account 315.2				
316.00	Misc. Power Plant Equipment				
	Arapahoe Unit 4		4.7775%	0.3965%	5.1740%
	Arapahoe Common		3.7673%	0.3127%	4.0800%
	Cherokee Unit 2 SC		2.6807%	0.2493%	2.9300%
	Cherokee Unit 3		2.3449%	0.2181%	2.5630%
	Cherokee Unit 4		1.4290%	0.1700%	1.5990%
	Cherokee Common		2.1380%	0.2040%	2.3420%
	Comanche Unit 1		1.3680%	0.1450%	1.5130%
	Comanche Unit 2		1.3560%	0.1370%	1.4930%
	Comanche Unit 3	(3)	1.8850%	0.1210%	2.0060%
	Comanche Common		1.6030%	0.1580%	1.7610%
	Craig Unit 1		1.5120%	0.0690%	1.5810%
	Craig Unit 2		1.4780%	0.0690%	1.5470%
	Craig Common		1.6400%	0.0740%	1.7140%
	Hayden Unit 1		1.6902%	0.1978%	1.8880%
	Hayden Unit 2		1.3970%	0.1710%	1.5680%
	Hayden Common		2.3100%	0.2540%	2.5640%
	Pawnee Unit 1		1.5700%	0.0710%	1.6410%
	Pawnee Common		2.3210%	0.0980%	2.4190%
	Valmont Unit 5		2.4879%	0.1891%	2.6770%
	Valmont Common		2.7063%	0.2057%	2.9120%
	Zuni Unit 2	(2)	0.0000%	0.0000%	0.0000%
	Zuni Common		4.9409%	0.6571%	5.5980%
	Total Account 316				
	Total Steam Production				
	HYDRAULIC PRODUCTION PLANT				
330.10	Land				
331.00	Structures & Improvements				
	Ames		1.4679%	0.0191%	1.4870%
	Cabin Creek		0.9324%	0.1296%	1.0620%
	Georgetown		1.6952%	0.0068%	1.7020%
	Salida		1.8055%	0.0325%	1.8380%
	Shoshone		1.6234%	0.0536%	1.6770%
	Tacoma		1.3804%	0.0276%	1.4080%
	Total Account 331				
332.00	Reservoirs, Dams & Waterways				
	Ames		1.5420%	0.0200%	1.5620%
	Cabin Creek		0.9587%	0.1333%	1.0920%
	Georgetown		2.3038%	0.0092%	2.3130%
	Salida		1.5658%	0.0270%	1.5928%
	Shoshone		0.8325%	0.0275%	0.8600%
	Tacoma		1.3500%	0.0270%	1.3770%
	Total Account 332				
333.00	Waterwheels, Turbines & Generators				
	Ames		0.9299%	0.0121%	0.9420%
	Cabin Creek		1.0773%	0.1497%	1.2270%
	Georgetown		1.0269%	0.0041%	1.0310%
	Salida		0.6965%	0.0125%	0.7090%
	Shoshone		1.7212%	0.0568%	1.7780%
	Tacoma		1.8147%	0.0363%	1.8510%
	Total Account 333				

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			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
334.00	Accessory Electric Equipment				
	Ames		2.4393%	0.0317%	2.4710%
	Cabin Creek		1.2581%	0.1749%	1.4330%
	Georgetown		1.6056%	0.0064%	1.6120%
	Salida		2.0010%	0.0360%	2.0370%
	Shoshone		2.2323%	0.0737%	2.3060%
	Tacoma		1.7667%	0.0353%	1.8020%
	Total Account 334				
334.20	Computers				
	Cabin Creek		1.1563%	0.1607%	1.3170%
	Total Account 334.2				
335.00	Misc. Power Plant Equipment				
	Ames		1.8095%	0.0235%	1.8330%
	Cabin Creek		1.4978%	0.2082%	1.7060%
	Georgetown		2.8665%	0.0115%	2.8780%
	Salida		3.6248%	0.0652%	3.6900%
	Shoshone		2.7396%	0.0904%	2.8300%
	Tacoma		1.8912%	0.0378%	1.9290%
	Total Account 335				
335.20	Recreational Facilities				
	Ames		2.3258%	0.0302%	2.3560%
	Cabin Creek		1.3565%	0.1885%	1.5450%
	Georgetown		2.2570%	0.0090%	2.2660%
	Salida		3.2711%	0.0589%	3.3300%
	Tacoma		1.6294%	0.0326%	1.6620%
	Total Account 335.2				
336.00	Roads, Railroads & Bridges				
	Ames		2.3722%	0.0308%	2.4030%
	Cabin Creek		0.9359%	0.1301%	1.0660%
	Salida		2.6189%	0.0471%	2.6660%
	Shoshone		1.0852%	0.0358%	1.1210%
	Tacoma		1.3029%	0.0261%	1.3290%
	Total Account 336				
	Total Hydraulic Production				
	OTHER PRODUCTION PLANT				
340.10	Land				
340.20	Land Rights		2.0000%	0.0000%	2.0000%
	Total Account 340				
341.00	Structures & Improvements				
	Alamosa		4.4734%	0.1566%	4.6300%
	Fruita CT		0.8302%	0.0548%	0.8850%
	FSV ST 1		1.3811%	0.0539%	1.4350%
	FSV GT 4		2.3994%	0.0936%	2.4930%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		1.6554%	0.0646%	1.7200%
	Ft. Lupton CT		2.4128%	0.1472%	2.5600%
	Valmont CT		0.7780%	0.0420%	0.8200%
	Total Account 341				
342.00	Fuel Holders, Producers & Access.				
	Alamosa		1.0058%	0.0352%	1.0410%
	Fruita CT		0.9756%	0.0644%	1.0400%
	FSV ST 1		2.3879%	0.0931%	2.4810%
	FSV GT 2		2.7469%	0.1071%	2.8540%
	FSV GT 3		2.7825%	0.1085%	2.8910%
	FSV GT 4		2.4321%	0.0949%	2.5270%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		1.6391%	0.0639%	1.7030%
	Ft. Lupton CT		3.6664%	0.2236%	3.8900%
	Valmont CT		1.2837%	0.0693%	1.3530%
	Total Account 342				

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			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
343.00	Prime Movers				
	FSV ST 1		2.1280%	0.0830%	2.2110%
	FSV GT 2		2.2281%	0.0869%	2.3150%
	FSV GT 3	(2)	1.8582%	0.2118%	2.0700%
	FSV Common		2.6266%	0.1024%	2.7290%
	Total Account 343				
344.00	Generators				
	Alamosa		1.5633%	0.0547%	1.6180%
	Blue Spruce	(4)	2.5000%	0.1887%	2.6887%
	Fruita CT		0.9653%	0.0637%	1.0290%
	FSV ST 1		1.3705%	0.0535%	1.4240%
	FSV GT 2		2.3272%	0.0908%	2.4180%
	FSV GT 3		2.6237%	0.1023%	2.7260%
	FSV GT 4		2.5881%	0.1009%	2.6890%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		2.5881%	0.1009%	2.6890%
	Ft. Lupton CT		3.7945%	0.2315%	4.0260%
	Rocky Mountain	(4)	2.5000%	0.3491%	2.8491%
	Wind - Hydrogen	(4)	6.6700%	0.0000%	6.6700%
	Valmont CT		1.8046%	0.0974%	1.9020%
	Total Account 344				
345.00	Accessory Electric Equipment				
	Alamosa		3.6184%	0.1266%	3.7450%
	Fruita CT		3.9428%	0.2602%	4.2030%
	FSV ST 1		1.3831%	0.0539%	1.4370%
	FSV GT 2		1.9838%	0.2262%	2.2100%
	FSV GT 4		2.4456%	0.0954%	2.5410%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		2.5958%	0.1012%	2.6970%
	Ft. Lupton CT		1.2875%	0.0785%	1.3660%
	Valmont CT		4.3197%	0.2333%	4.5530%
	Total Account 345				
345.20	Computers				
	FSV ST 1		1.6487%	0.0643%	1.7130%
	FSV Common		2.1193%	0.0827%	2.2020%
	Total Account 345.2				
346.00	Misc. Power Plant Equipment				
	Alamosa		0.9430%	0.0330%	0.9760%
	Fruita CT		1.0610%	0.0700%	1.1310%
	FSV ST 1		1.4379%	0.0561%	1.4940%
	FSV GT 4		2.4283%	0.0947%	2.5230%
	FSV GT 5	(3)	2.3680%	0.1940%	2.5620%
	FSV GT 6	(3)	2.3680%	0.1940%	2.5620%
	FSV Common		2.5303%	0.0987%	2.6290%
	Ft. Lupton CT		1.3713%	0.0837%	1.4550%
	Valmont CT		4.5873%	0.2477%	4.8350%
	Total Account 346				
	Total Other Production				
	Total Electric Production				
	TRANSMISSION PLANT				
350.10	Land				
350.20	Land Rights		1.0300%	0.0000%	1.0300%
352.00	Structures & Improvements		1.3091%	0.1309%	1.4400%
352.10	Structures & Improvements-Production		1.3091%	0.1309%	1.4400%
353.00	Station Equipment		1.6481%	0.1319%	1.7800%
353.10	Station Equipment-Production		1.6481%	0.1319%	1.7800%
354.00	Towers & Fixtures		1.1238%	0.0562%	1.1800%
355.00	Poles & Fixtures		1.5619%	0.0781%	1.6400%
356.00	OH Conductors & Devices		1.7048%	0.0852%	1.7900%
357.00	UG Conduit		1.9400%	0.0000%	1.9400%
358.00	UG Conductors & Devices		1.8800%	0.0000%	1.8800%
359.00	Roads & Trails		0.9700%	0.0000%	0.9700%
	Total Transmission				

Public Service Company of Colorado
Electric and Common Depreciation Rates
Proceeding No. 14AL-0660E

			Approved (1)		
Account Number	Description	Notes	Depr Rate	COR Depr Rate	Tot Depr Rate
	DISTRIBUTION PLANT				
360.10	Land				
360.20	Land Rights		1.0900%	0.0000%	1.0900%
361.00	Structures & Improvements		1.7100%	0.0000%	1.7100%
361.10	Structures & Improvements-Production		1.7100%	0.0000%	1.7100%
362.00	Station Equipment		1.7826%	0.2674%	2.0500%
362.10	Station Equipment-Production		1.7826%	0.2674%	2.0500%
364.00	Poles, Towers & Fixtures		2.8077%	0.8423%	3.6500%
365.00	OH Conductors & Devices		2.3643%	0.9457%	3.3100%
366.00	UG Conduit		1.9135%	0.0765%	1.9900%
367.00	UG Conductors & Devices		1.8636%	0.1864%	2.0500%
368.00	Line Transformers		2.2100%	0.0000%	2.2100%
369.00	Services		1.9580%	0.3720%	2.3300%
369.10	Services-Overhead		1.9580%	0.3720%	2.3300%
369.20	Services-Underground		1.9580%	0.3720%	2.3300%
370.00	Meters		3.9700%	0.0000%	3.9700%
370.20	AMR Equipment		8.8100%	0.0000%	8.8100%
371.00	Installation on Customer Premises		0.8333%	0.1667%	1.0000%
373.00	Street Lighting & Signal Systems		2.4583%	0.4917%	2.9500%
	Total Distribution				
	ELECTRIC GENERAL PLANT				
389.00	Land				
390.00	Structures & Improvements		4.8800%	0.0000%	4.8800%
390.10	General Buildings		2.9800%	0.0000%	2.9800%
390.20	Partitions		7.6900%	0.0000%	7.6900%
391.00	Office Furniture & Equipment		4.7500%	0.0000%	4.7500%
391.20	Computer Hardware		20.0000%	0.0000%	20.0000%
392.00	Transportation Equipment		9.0000%	0.0000%	9.0000%
393.00	Stores Equipment		3.1700%	0.0000%	3.1700%
394.00	Tools, Shop & Garage Equipment		3.8000%	0.0000%	3.8000%
395.00	Laboratory Equipment		9.5000%	0.0000%	9.5000%
396.00	Power Operated Equipment		9.0000%	0.0000%	9.0000%
397.00	Communication Equipment		6.6700%	0.0000%	6.6700%
398.00	Miscellaneous Equipment		5.0000%	0.0000%	5.0000%
	Total Electric General				
	Total Electric Plant				
	COMMON INTANGIBLE PLANT				
301.00	Organization Costs				
302.00	Franchises & Consents	(6)			
303.04	Misc Computer Software-5 Year		20.0000%	0.0000%	20.0000%
303.04	Misc Computer Software-10 Year		10.0000%	0.0000%	10.0000%
303.14	CRS Computer Software		10.0000%	0.0000%	10.0000%
	Total Common Intangible				
	COMMON GENERAL PLANT				
389.01	General Land Owned in Fee		0.0000%	0.0000%	0.0000%
390.00	Genl Structures & Improve		2.7304%	0.4096%	3.1400%
390.07	Genl Str & Imp-Lease Bldg-CPR	(7)			
390.07	Genl Str & Imp-Lease Bldg-106		6.0606%	0.0000%	6.0606%
390.08	Genl Str & Imp-Partitions		3.8000%	0.0000%	3.8000%
390.85	GS&I-1800 Leasehold Imp	(5)	6.6666%	0.0000%	6.6666%
391.00	General Office Furn & Eqp		4.7500%	0.0000%	4.7500%
391.04	Computer Hardware		20.0000%	0.0000%	20.0000%
391.05	Genl Off Eq-Comp 3 Yr Life		33.3300%	0.0000%	33.3300%
391.07	Genl Office Equip-Leased		20.0000%	0.0000%	20.0000%
391.09	Genl Off Eq-Part Lease Fac		5.0000%	0.0000%	5.0000%
392.00	General Transportation Eqp		9.0000%	0.0000%	9.0000%
393.00	General Stores Equipment		3.1700%	0.0000%	3.1700%
394.00	General Tools & Shop Equip		3.8000%	0.0000%	3.8000%
395.00	Laboratory Equipment		9.5000%	0.0000%	9.5000%
396.00	General Power Operated Eqp		9.0000%	0.0000%	9.0000%
397.00	General Communication Eqp		6.6700%	0.0000%	6.6700%
398.00	General Miscellaneous Eqp		5.0000%	0.0000%	5.0000%
	Total Common General Plant				
	Total Common Plant				

Notes:
(1) Approved rates are from Docket 06S-234EG, unless specified in the Notes column.
(2) Approved rates are from Docket 02S-315EG
(3) Depreciation rates for Comanche 3, FSV GT 5 and FSV GT 6 were approved in Docket 08S-520E.
(4) Depreciation rates set in Docket 11-947E.
(5) Amortized over the 15 year lease term.
(6) Amortized over the terms of the franchise agreements
(7) Amortized over the lease term.

Public Service Company of Colorado
Proceeding No. 14AL-0660E

Pension Reporting: To provide greater transparency, the Company will file three reports each April 30th providing qualified pension details for the following periods:

(1) Actual results for the prior year
(2) Forecasted results for the current year
(3) Forecasted results for the next four years

These reports will list data separately for the three qualified pension plans that impact Public Service, which are the PSCo Bargaining Pension Plan (only Public Service bargaining participants), the NCE Non-Bargaining Pension Plan (includes non-bargaining employees from both Public Service and Southwestern Public Service) and the Xcel Energy Pension Plan or "XEPP" portion associated with the Service Company employees. These reports will report data at both the company level (Public Service & Xcel Energy Services) and the PSCo electric retail jurisdiction, where applicable.

<u>Components of the Report for Year Proceeding Report Year</u>[1]

1. Qualified pension cost incurred
2. Annual return on plan assets
3. Annual return on plan assets as a percentage
4. Employer pension contributions
5. Liability gains and losses arising during the year
6. Asset gains and losses arising during the year
7. Change in Projected Benefit Obligation (PBO) roll-forward (10-K Format)
8. Change in Fair value of plan assets roll-forward (10-K Format)
9. PBO Funded status
10. Minimum funding requirements – by plan
11. Maximum funding requirements by plan
12. The unfunded qualified pension liability at year end
13. The life to date total unrecognized losses at year end
14. The GAAP prepaid pension asset balance at year end - Gross
15. The GAAP prepaid pension asset balance at year end (net of ADIT)
16. The current year additional prepaid pension asset amortization (Gross and net of ADIT)
17. The life to date additional prepaid pension asset amortization -excluding the current year (Gross and Net of ADIT)
18. The ratemaking prepaid pension asset balance at year end (Gross and Net of ADIT)
19. The four main assumptions used in the pension calculations (mortality, discount rate, EROA, salary scale).
20. Copy of the most recent filed 5500, with attachments

[1] For example, on April 30, 2015 the year proceeding would be calendar year ending December 31, 2014.

Public Service Company of Colorado
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Components of the Report for Current Year[2] - Filed as CONFIDENTIAL

1. Qualified pension cost incurred
2. Employer pension contributions
3. The GAAP prepaid pension asset balance at year end (Gross and net of ADIT)
4. The life to date additional prepaid pension asset amortization (Gross and net of ADIT)
5. The ratemaking prepaid pension asset balance at year end (Gross and net of ADIT)
6. Benefits cost elements of FAS 87 to arrive at net periodic pension cost
7. The four main assumptions used in the pension calculations (mortality, discount rate, EROA, salary scale).

Components of the Report for Future Years 2-5 – Filed as HIGHLY CONFIDENTIAL[3]

1. Qualified pension cost incurred
2. Employer pension contributions
3. The GAAP prepaid pension asset balance at year end (Gross and net of ADIT)
4. The life to date additional prepaid pension asset amortization (Gross and net of ADIT)
5. The ratemaking prepaid pension asset balance at year end (Gross and net of ADIT)
6. Benefits cost elements of FAS 87 to arrive at net periodic pension cost
7. The four main assumptions used in the pension calculations (mortality, discount rate, EROA, salary scale).

[2] The Current Year is the year in which the report is being filed. For example, if the report was filed on April 30, 2015, the Current Year would be calendar year ending December 31, 2015.
[3] Upon filing of the settlement agreement the Company will request the Future Years 2-5 of the report be designated as HIGHLY CONFIDENTIAL with access restricted to representatives of the Commission Staff and the OCC, and will submit the necessary documentation to support such a request. The other Settling Parties reserve the right to request access, contest or object to such a request.

Public Service Company of Colorado
Proceeding No. 14AL-00660E

Public Service Company of Colorado
Annual Qualified Pension Compliance Filing
Actuals Calendar Year 2014
(Amounts in 000s)

		Total Company			PSCo Electric Retail Jurisdiction				
		PSCo Bargaining - PSCo	NCE Non-Bargaining - PSCo	Xcel Energy Pension Plan - Xcel Energy Service Portion	PSCo Bargaining - PSCo	NCE Non-Bargaining - PSCo	Xcel Energy Pension Plan - Xcel Energy Service Portion	Total	
A	Actual qualified pension cost incurred	-	-	-	-	-	-	-	
B	Actual return on plan assets from 10-K	-	-	-	-	-	-	-	
C	Actual return on plan assets as a percentage	0%	0%	0%	0%	0%	0%	0% [1]	[1] Weighted Average
D	Employer contributions from 10-K	-	-	-	-	-	-	-	
E	Liability gains/(Losses) arising during the year	-	-	-	-	-	-	-	
F	Asset gain/(losses) arising during the year	-	-	-	-	-	-	-	
	Change in Projected Benefit Obligation:								
G	Obligation at Jan. 1								
H	Service Cost								
I	Interest Cost								
J	Transfer from other plan								
K	Plan amendments								
L	Actuarial (gain) loss								
M	Benefit payments								
N	Obligation at Dec. 31								
	Change in Fair Value of Plan Assets:								
O	Fair value of plan assets at Jan. 1								
P	Actual return on plan assets								
Q	Employer contributions								
R	Transfer from other plan								
S	Benefit payments								
T	Fair value of plan assets at Dec. 31								
U	PBO Funded Status	-	-	-	N/A	N/A	N/A	N/A	
V	Minimum contributions	-	-	-					
W	Maximum contributions	-	-	-					
X	Unfunded qualified pension liability from 10-K *	-	-	-	-	-	-	-	
Y	Total unrecognized losses from 10-K *	-	-	-	-	-	-	-	
Z	Gross Prepaid asset balance on December 31st GAAP	-	-	-	-	-	-	-	= X - Y
AA	Prepaid asset balance on December 31st GAAP net of ADIT	-	-	-	-	-	-	-	
	Other Ratemaking Amounts:								
BB	Gross Current year special prepaid amortization Docket No. 14AL-0660E	N/A	N/A	N/A	-	-	N/A	-	
CC	Current year special prepaid amortization Docket No. 14AL-0660E (Net of ADIT)	N/A	N/A	N/A			N/A		
DD	Gross Life to date special prepaid amortization Docket No. 14AL-0660E **	N/A	N/A	N/A	-	-	N/A	-	
EE	Life to date special prepaid amortization Docket No. 14AL-0660E (Net of ADIT) **	N/A	N/A	N/A			N/A		
FF	Gross Year end prepaid pension asset balance - Ratemaking	N/A	N/A	N/A	-	-	-	-	= Z - BB - DD
GG	Year end prepaid pension asset balance - Ratemaking (Net of ADIT)	N/A	N/A	N/A	-	-	-	-	= AA - CC - EE
	Benefit Costs								
HH	Service cost				-	-	-	-	
II	Interest cost				-	-	-	-	
JJ	Expected return on plan assets				-	-	-	-	
KK	Amortization of prior service (credit) cost				-	-	-	-	
LL	Amortization of net loss				-	-	-	-	
MM	Net periodic pension cost (FAS 87)				-	-	-	-	
	Significant Assumptions:								
NN	Mortality				N/A	N/A	N/A	N/A	
OO	Discount rate				N/A	N/A	N/A	N/A	
PP	Salary scale				N/A	N/A	N/A	N/A	
QQ	Expected return on assets (EROA)				N/A	N/A	N/A	N/A	

Footnotes
* The amount attibutable to the XES portions are not identifiable in the 10-K
** Does not include amortization from current year

Public Service Company of Colorado
Annual Qualified Pension Compliance Filing
Calendar Years 2015
(Amounts in 000s)

		Total Company			PSCo Electric Retail Jurisdiction			
		PSCo Bargaining - PSCo	NCE Non-Bargaining - PSCo	Xcel Energy Pension Plan - Xcel Energy Service Portion	PSCo Bargaining - PSCo	NCE Non-Bargaining - PSCo	Xcel Energy Pension Plan - Xcel Energy Service Portion	Total
A	Qualified pension cost 2015	-	-	-	-	-	-	-
B	Contributions 2015	-	-	-	-	-	-	-
C	Gross Year end prepaid pension asset balance GAAP 2015	-	-	-	-	-	-	-
D	Year end prepaid pension asset balance GAAP 2015 (Net of ADIT)	-	-	-	-	-	-	-
E	Gross Life to Date - Special prepaid amortization Docket No. 14AL-0660E 2015	N/A	N/A	N/A	-	-	N/A	-
F	Life to Date - Special prepaid amortization Docket No. 14AL-0660E 2015 (Net of ADIT)	N/A	N/A	N/A	-	-	N/A	-
G	Gross Year-end prepaid pension asset balance ratemaking 2015	N/A	N/A	N/A	-	-	-	-
H	Year-end prepaid pension asset balance ratemaking 2015 (Net of ADIT)	N/A	N/A	N/A	-	-	-	-
	Benefit Costs:							
I	Service cost				-	-	-	-
J	Interest cost				-	-	-	-
K	Expected return on plan assets				-	-	-	-
L	Amortization of prior service (credit) cost				-	-	-	-
M	Amortization of net loss				-	-	-	-
N	Net periodic pension cost (FAS 87)				-	-	-	-
	Significant Assumptions:							
O	Mortality	-	-	-	N/A	N/A	N/A	N/A
P	Discount rate	-	-	-	N/A	N/A	N/A	N/A
Q	Expected return on assets (EROA)	-	-	-	N/A	N/A	N/A	N/A
R	Salary scale	-	-	-	N/A	N/A	N/A	N/A

Public Service Company of Colorado
Proceeding No. 14AL-00660E

Public Service Company of Colorado
Annual Qualified Pension Compliance Filing
Calendar Years 2016-2019
(Amounts in 000s)

		Total Company			PSCo Electric Retail Jurisdiction			
		PSCo Bargaining - PSCo	NCE Non-Bargaining - PSCo	Xcel Energy Pension Plan - Xcel Energy Service Portion	PSCo Bargaining - PSCo	NCE Non-Bargaining - PSCo	Xcel Energy Pension Plan - Xcel Energy Service Portion	Total
A	Qualified pension cost 2016	-	-	-	-	-	-	-
B	Qualified pension cost 2017	-	-	-	-	-	-	-
C	Qualified pension cost 2018	-	-	-	-	-	-	-
D	Qualified pension cost 2019	-	-	-	-	-	-	-
E	Contributions 2016	-	-	-	-	-	-	-
F	Contributions 2017	-	-	-	-	-	-	-
G	Contributions 2018	-	-	-	-	-	-	-
H	Contributions 2019	-	-	-	-	-	-	-
I	Gross Year end prepaid pension asset balance GAAP 2016	-	-	-	-	-	-	-
J	Gross Year end prepaid pension asset balance GAAP 2017	-	-	-	-	-	-	-
K	Gross Year end prepaid pension asset balance GAAP 2018	-	-	-	-	-	-	-
L	Gross Year end prepaid pension asset balance GAAP 2019	-	-	-	-	-	-	-
M	Year end prepaid pension asset balance GAAP 2016 (Net of ADIT)	-	-	-	-	-	-	-
N	Year end prepaid pension asset balance GAAP 2017 (Net of ADIT)	-	-	-	-	-	-	-
O	Year end prepaid pension asset balance GAAP 2018 (Net of ADIT)	-	-	-	-	-	-	-
P	Year end prepaid pension asset balance GAAP 2019 (Net of ADIT)	-	-	-	-	-	-	-
Q	Gross Life to Date - Special prepaid amortization Docket No. 14AL-0660E 2016	N/A	N/A	N/A	-	-	N/A	-
R	Gross Life to Date - Special prepaid amortization Docket No. 14AL-0660E 2017	N/A	N/A	N/A	-	-	N/A	-
S	Gross Life to Date - Special prepaid amortization Docket No. 14AL-0660E 2018	N/A	N/A	N/A	-	-	N/A	-
T	Gross Life to Date - Special prepaid amortization Docket No. 14AL-0660E 2019	N/A	N/A	N/A	-	-	N/A	-
U	Life to Date - Special prepaid amortization Docket No. 14AL-0660E 2016 (Net of ADIT)	N/A	N/A	N/A	-	-	N/A	-
V	Life to Date - Special prepaid amortization Docket No. 14AL-0660E 2017 (Net of ADIT)	N/A	N/A	N/A	-	-	N/A	-
W	Life to Date - Special prepaid amortization Docket No. 14AL-0660E 2018 (Net of ADIT)	N/A	N/A	N/A	-	-	N/A	-
X	Life to Date - Special prepaid amortization Docket No. 14AL-0660E 2019 (Net of ADIT)	N/A	N/A	N/A	-	-	N/A	-
Y	Gross Year end prepaid pension asset balance ratemaking 2016	N/A	N/A	N/A	-	-	-	-
Z	Gross Year end prepaid pension asset balance ratemaking 2017	N/A	N/A	N/A	-	-	-	-
AA	Gross Year end prepaid pension asset balance ratemaking 2018	N/A	N/A	N/A	-	-	-	-
BB	Gross Year end prepaid pension asset balance ratemaking 2019	N/A	N/A	N/A	-	-	-	-
CC	Year end prepaid pension asset balance ratemaking 2016 (Net of ADIT)	N/A	N/A	N/A	-	-	-	-
DD	Year end prepaid pension asset balance ratemaking 2017 (Net of ADIT)	N/A	N/A	N/A	-	-	-	-
EE	Year end prepaid pension asset balance ratemaking 2018 (Net of ADIT)	N/A	N/A	N/A	-	-	-	-
FF	Year end prepaid pension asset balance ratemaking 2019 (Net of ADIT)	N/A	N/A	N/A	-	-	-	-
	Benefit Costs:							
GG	Service cost				-	-	-	-
HH	Interest cost				-	-	-	-
II	Expected return on plan assets				-	-	-	-
JJ	Amortization of prior service (credit) cost				-	-	-	-
KK	Amortization of net loss				-	-	-	-
LL	Net periodic pension cost (FAS 87)				-	-	-	-
	Significant Assumptions:							
MM	Mortality	-	-	-	N/A	N/A	N/A	N/A
NN	Discount rate	-	-	-	N/A	N/A	N/A	N/A
OO	Expected return on assets (EROA)	-	-	-	N/A	N/A	N/A	N/A
PP	Salary scale	-	-	-	N/A	N/A	N/A	N/A

PUBLIC SERVICE COMPANY OF COLORADO

P.O. Box 840
Denver, CO 80201-0840

COLO. PUC No. 7 Electric

Sheet No. 111

Cancels
Sheet No.

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

APPLICABILITY

All rate schedules for electric service are subject to an Electric Commodity Adjustment (ECA) to reflect the cost of energy utilized to supply electric service. The Electric Commodity Adjustment Factors for all applicable rate schedules are as set forth on Sheet No. 111~~HF~~ and will be applied to all kilowatt-hours sold by the Company with the exception of any buy-through kilowatt-hours (BT kWh) sold to participants in the Interruptible Service Option Credit (ISOC) program who buy through an Economic Interruption. The ECA Factors for lighting service bills and other non-metered service will be determined by applying the ECA Factor to the calculated monthly kilowatt-hour consumption.

TIME-OF-USE ECA FACTORS APPLICABILITY

All kilowatt-hours used under any Rate Schedule for Commercial and Industrial Primary, Transmission or Special Contract Service customers shall be billed under the appropriate Time-of-Use ECA Factor. Customers that receive electric service under any Commercial and Industrial Secondary Service Rate Schedule that have measured demands of three hundred kilowatt (300 kW) or more for twelve (12) consecutive months may elect to be billed prospectively under the Secondary Time-of-Use ECA Factor. Subsequent to a customer’s election to be billed under the Secondary Time-of-Use ECA Factor, customer must have a measured demand of three hundred kilowatts (300 kW) or more every month, except a customer may have one month within the previous twelve (12) months where the customer demand is less than three hundred kilowatts (300 kW). In the event that a second month occurs in any twelve month period where the customer’s measured demand is less than three hundred kilowatts (300 kW), the Company shall bill the customer under the non-Time-of-Use Secondary ECA Factor.

The On-peak hours shall be 9:00 AM to 9:00 PM for all non-holiday weekdays. Holidays are defined as New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The Off-peak period shall be all other hours. The On-peak and Off-peak price differentials are based on the ratio of system marginal costs for a calendar year. The On-peak and Off-peak price ratio will be projected annually and will be filed with the Commission on the first business day of November, and shall remain in effect for the subsequent calendar year. The TOU ECA rates will be updated with the Quarterly ECA rates and will be determined by applying the fixed annual On-peak and Off-peak ratios to the quarterly ECA cost of service.

(Continued on Sheet No. 111A)

COLO. PUC No. 7 Electric

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 111A

P.O. Box 840
Denver, CO 80201-0840

Cancels
Sheet No.

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

TIME-OF-USE NOTICE AND METERING REQUIREMENTS

Customers receiving service under the Time-of-Use ECA must have their usage metered by an Interval Data Recorder (“IDR”) meter. If a requesting customer is not currently metered with an IDR meter the Company will install an IDR meter as soon as reasonably practicable and the customer will be eligible for the Time-of-Use rate beginning with the first billing cycle immediately subsequent to the installation of the IDR meter.

ELECTRIC COMMODITY ADJUSTMENT QUARTERLY FILING

The Company shall file each quarter, on not less than fifteen (15) days notice, an application with the ECA Factors on Sheet No. 111H~~F~~ to be effective on the first day of the month of the next calendar quarter. The Company may also file for more frequent changes to the ECA factors, subject to Commission Approval.

ELECTRIC COMMODITY ADJUSTMENT

The ECA shall be calculated quarterly with the new ECA Factors to be effective on a prorated basis on the first day of the quarter. The ECA Factors shall be determined by dividing the Quarterly ECA Revenue Requirement by the projected kilowatt-hour sales to which the ECA is applicable for the next calendar quarter. The ECA Factors shall be differentiated by service delivery voltage to reflect line losses.

LOSS FACTOR

The ECA Factors take into account service delivery voltage to reflect line losses. Loss Factors are as follows:

Transmission	1.0000
Primary	1.0235
Secondary	1.0500

Primary and Secondary voltage losses may be updated by the Company from time to time.

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ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

ELECTRIC COMMODITY ADJUSTMENT – Cont'd

8) NGS Balance shall be the total cost for the sales of natural gas less the natural gas sales credit for all revenue received by the Company for the sale of natural gas to Southwest Generation for their Fountain Valley Facility.

The ECA revenue collected for the quarter will be adjusted for billing cycle lag.

Interest shall accrue monthly on the average monthly deferred balance (whether the balance is positive or negative). The monthly interest rate shall be at a rate equal to the average of the daily rates for Commercial Paper, Financial, 3-Month rates, published by the United States Federal Reserve H.15 report (http://www.federalreserve.gov/releases/h15/data.htm).

ADJUSTMENT FOR SHORT-TERM SALES MARGIN

Positive short-term sales margins from the calendar year shall be shared with retail customers through an adjustment to the ECA. Margin sharing shall be calculated separately for both the Generation Book margins and Proprietary Book margins. Proprietary Book margins shall be calculated from the Company's share of margins under the Joint Operating Agreement. Within each of these books, the retail jurisdictional Gross Margin shall be aggregated annually. If the aggregated Gross Margin from either book is negative, the negative margin shall not be passed on to retail customers.

If the annual retail jurisdictional aggregated Gross Margin in either book is positive, then such positive annual retail jurisdictional Gross Margin shall be shared annually with retail customers through the ECA as follows:

1) Generation Book: Gross Margin in excess of $678,027~~789,519~~ for calendar year 201~~2~~5 and subsequent years shall be shared ninety percent (90%) retail customers/ten percent (10%) Company.

2) Proprietary Book: Gross Margin in excess of $514,659~~508,794~~ for calendar year 201~~2~~5 and subsequent years shall be shared ten percent (10%) retail customers/ninety percent (90%) Company.

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ELECTRIC COMMODITY ADJUSTMENT

ADJUSTMENT FOR SHORT-TERM SALES MARGIN – Cont'd

The Company shall include in its quarterly filing for effect April 1 of each year a report setting forth the retail customer share of positive short-term sales margins from the prior calendar year. The total positive short-term sales margins will be divided by three (3), and the quotient shall be subtracted from each quarterly ECARR for the remainder of the calendar year.

ADJUSTMENT FOR SO_2 ALLOWANCE MARGINS

Margins earned from the sale of SO_2 allowances by the Company shall be shared with retail customers in accord with Commission orders. The Company shall include in its quarterly filing for effect April 1 of each year a report setting forth the retail customer share of the SO_2 allowance margins from the prior calendar year. The margins to be shared will be divided by three (3), and the quotient shall be subtracted from each quarterly ECARR for the remainder of the calendar year.

PUEBLO INCENTIVE PROPERTY TAX CREDIT

An adjustment shall be made to the Deferred Account Balance to include the flow-through to customers of the amount of any incentive property tax credit or payment received by the Company from the City of Pueblo or Pueblo County pursuant to agreements entered into by the Company with the City of Pueblo and Pueblo County in 2005, commencing with incentive property tax credits or payments attributable to property taxes payable for tax year 2012. As to each regular quarterly ECA application, the adjustment to the applicable Deferred Account Balance shall include all such incentive property tax credits and payments received by the Company during the quarterly period ending as of the last day of the calendar month immediately preceding the date of the ECA application.

ADJUSTMENT FOR TRUE-UP OF COSTS BETWEEN THE RESA AND ECA

An adjustment shall be made to the ECA Deferred Account Balance to collect the component of costs that were charged to the Renewable Energy Standard Adjustment ("RESA") that should have been charged to the ECA for the period 2010 – 2012. An adjustment to the ECA Deferred Account Balance shall commence beginning with the subsequent month after the Company receives Commission approval of said adjustment and shall be collected in the ECA Deferred Account Balance equally over a period of twelve months.

EQUIVALENT AVAILABILITY FACTOR PERFORMANCE MECHANISM

The Equivalent Availability Factor Performance Mechanism ("EAFPM") will apply only to the Company's performance in calendar years 2015, 2016 and 2017. An adjustment shall be made to the Deferred Account Balance to include the incentive or penalty attributable to the EAFPM for performance in 2015, 2016 and 2017.

(Continued on Sheet No. 111F)

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

EQUIVALENT AVAILABILITY FACTOR PERFORMANCE MECHANISM - CONT'D

The Company shall file on or before April 1, 2016, April 1, 2017, and April 1, 2018, a report detailing the results of the EAFPM for the previous calendar year and requesting through an Application Commission approval of an adjustment as applicable to the ECA Deferred Account Balance. Once a final Commission Decision has been issued on the Company's Application, the total amount of the approved incentive or penalty will be included in the subsequent quarterly filing.

For calendar years 2015, 2016 and 2017, the Company shall calculate the Current Year Weighted Average EAF for the Eligible Units.

If the Current Year Weighted Average EAF for calendar year 2015 is at or above 86.19%, then the Company will earn a before-tax incentive of $3 million. If the Current Year Weighted Average EAF for calendar year 2015 is at or below 83.79%, then the Company will be assessed a before-tax penalty of $3 million. If the Current Year Weighted Average EAF for calendar year 2015 falls between 83.79% and 86.19%, then the Company will neither earn an incentive nor be assessed a penalty.

If the Current Year Weighted Average EAF for calendar year 2016 or calendar year 2017 is at or above 86.57%, then the Company will earn a before-tax incentive of $3 million. If the Current Year Weighted Average EAF for calendar year 2016 is at or below 84.49%, then the Company will be assessed a before-tax penalty of $3 million. If the Current Year Weighted Average EAF for calendar year 2016 falls between 84.49% and 86.57%, then the Company will neither earn an incentive nor be assessed a penalty.

The Company shall exclude the following circumstances from the Current Year EAF calculation:

1.) Outage events that are classified as Outside Management Control in the Generating Availability Data System ("GADS").
2.) All outage events that are specifically attributable to an order from a state or federal regulatory agency or an adopted state or federal law.

(Continued on Sheet No. 111G)

ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

EQUIVALENT AVAILABILITY FACTOR PERFORMANCE MECHANISM - CONT'D

For purposes of this Equivalent Availability Factor Incentive Mechanism section, the following definitions will apply:

Eligible Units for 2015. Cherokee 4, Comanche 1-3, Hayden 1-2, Pawnee, Fort St. Vrain 1-4 and Rocky Mountain Energy Center 1-3.

Eligible Units for 2016 and 2017. Cherokee 4-7, Comanche 1-3, Hayden 1-2, Pawnee, Fort St. Vrain 1-4 and Rocky Mountain Energy Center 1-3.

Equivalent Availability Factor ("EAF"). The total number of available hours for the specified time period minus the equivalent derated hours, both planned, unplanned and seasonal, and then divided by the number of hours in the same period. The result is then multiplied by 100 percent. The EAF shall be calculated consistent with the North American Electric Reliability Corporation requirements as reported in GADS.

Current Year Weighted Average EAF. The average of the EAFs of the Eligible Units in the current year, weighted by the Net Maximum Capacity of the Eligible Units.

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ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

ECA FACTORS FOR THE FIRST QUARTER OF 2015

ECA Factors for Billing Purposes

Residential, applicable to all kilowatt-hours used under any Rate Schedule for Residential Service	$0.03340/kWh
Small Commercial and Non-Metered, applicable to all kilowatt-hours used under any Rate Schedules for Small Commercial Service and Non-Metered Service	$0.03340/kWh
Commercial and Industrial Service at Secondary Voltage applicable to all kilowatt-hours used under any Rate Schedules for Commercial and Industrial Secondary Service Rate Schedules for Commercial and Industrial Service	$0.03340/kWh
Optional Time-of-Use Off-Peak	$0.02770/kWh
On-Peak to Off-Peak Ratio	1.48
Optional Time-of-Use On-Peak	$0.04100/kWh
Commercial and Industrial Service at Primary Voltage, applicable to all kilowatt-hours used under any Rate Schedules for Commercial and Industrial Primary or Special Contract Service	
Mandatory Time-of-Use Off-Peak	$0.02751/kWh
On-Peak to Off-Peak Ratio	1.48
Mandatory Time-of-Use On-Peak	$0.04071/kWh
Commercial and Industrial Service at Transmission Voltage, applicable to all kilowatt-hours used under any Rate Schedules for Commercial and Industrial Transmission Service	
Mandatory Time-of-Use Off-Peak	$0.02711/kWh
On-Peak to Off-Peak Ratio	1.48
Mandatory Time-of-Use On-Peak	$0.04012/kWh
Lighting, applicable to all kilowatt-hours used under any Rate Schedule for Commercial Lighting or Public Street Lighting Service	$0.03340/kWh

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ELECTRIC RATES	RATE
ELECTRIC SERVICE	
MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE	
Under this schedule, the Company will specifically bill the customer for all maintenance and replacement of street lighting facilities, other than what is provided under each lighting service schedule, in accordance with the following rates, percentages, and general criteria.	
Labor	
For work performed during normal working hours, per man-hour..	$~~54.00~~57.00
For work performed during hours other than normal working hours, and except for Sundays and holidays, per man-hour..	~~79.00~~94.00
For work performed on Sundays and holidays, per man hour..	~~113.00~~112.00
Materials	
Stores Overhead Percentage............................	9.04%
The above percentage will be applied to and then added to the Company's individual materials costs to develop the total materials charge. Individual materials costs will be charged on a current actual cost basis and will be subject to change without notice.	
Vehicles	
1/2 Ton Pick-up Truck (12 Series):	
Per Hour	~~8.25~~8.23

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ELECTRIC RATES	RATE
ELECTRIC SERVICE	
MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE	
Vehicles - Cont'd	
3/4 or 1 Ton Truck, Special Body, 6,200-9,600 GVW (18 Series) Per Hour	$ ~~8.39~~11.83
1 Ton Truck, Special Body, 10,000-16,000 GVW (20 Series): Per Hour	~~14.49~~17.92
Utility Truck (21 Series): Per Hour	~~18.32~~14.54

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ELECTRIC RATES	RATE
ELECTRIC SERVICE	
MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE	
Vehicles - Cont'd	
Welding Truck (26 Series): Per Hour	$ ~~10.27~~11.74
Line Center Mount Truck (30 Series): Per Hour	~~18.47~~19.41
2 Ton Truck (31 Series): Per Hour	30.44
Boom Truck (32 Series): Per Hour	~~22.38~~21.90
35 Foot One-man Bucket Truck (33 Series): Per Hour	~~19.48~~20.04
40 Foot One-man Bucket Truck (34 Series): Per Hour	~~22.80~~21.33
50 Foot One-man Bucket Truck (35 Series): Per Hour	~~16.33~~15.96
85 Foot and Higher Two-man Bucket Truck (37 Series): Per Hour	~~79.38~~35.09

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ELECTRIC SERVICE

MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE

Vehicles - (Cont'd)

	RATE
Dump Truck (38 Series): Per Hour	$ ~~23.28~~20.93
Trencher (44 Series): Per Hour	~~14.90~~11.45
Earthboring Machine, Truck or Trailer Mounted (46 Series): Per Hour	100.00
Portable Welder or Air Compressor (58 Series): Per Hour	~~6.47~~6.83
Multiple Axle Trailer (61 Series): Per Hour	~~4.47~~4.81
Backhoe (62 Series): Per Hour	15.53
Misc. Boring & Restoration Truck (63 Series): Per Hour	37.57
Misc. Boring & Restoration Equipment (64 Series): Per Hour	23.97

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ELECTRIC RATES	RATE
ELECTRIC SERVICE	
SCHEDULE OF CHARGES FOR RENDERING SERVICE	
To institute or reinstitute electric service requiring a premise visit within:	
24 hours	$ ~~35.00~~38.00
12 hours	~~73.00~~77.00
To institute or reinstitute both gas and electric service requiring a premise visit within:	
24 hours	~~114.00~~96.00
12 hours	~~133.00~~132.00
To provide a non-regularly scheduled final meter Reading at customers request	24.00
To transfer service at a specific location from one customer to another customer where such service is continuous, either electric service or both electric and gas service at the same time not requiring a premise visit	8.00
To perform non-gratuitous labor for service work, not specified below, (not including appliance repair and premium power) in addition to charges for materials, is as follows:	
Trip Charge	~~38.00~~40.00
(Assessed when no actual service work is performed, other than a general diagnosis of the customer's problem)	
For service work during normal working hours per man-hour	~~71.00~~75.62
Minimum Charge, one hour	~~71.00~~75.62
An overtime rate will be applicable to non-gratuitous labor for service work performed before and after normal working hours of 8:00 AM to 5:00 PM Monday through Saturday. The overtime rate shall be,	
per man-hour	~~87.00~~94.26
Minimum Charge, one hour	~~87.00~~94.26

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ELECTRIC RATES

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ELECTRIC SERVICE

SCHEDULE OF CHARGES FOR RENDERING SERVICE

When such service work is performed on Sundays and holidays, per man hour	~~102.00~~112.90
Minimum Charge, one hour	~~102.00~~112.90

When customer requests one or more of the specific non-gratuitous services listed below to be performed at a time specified by the customer that is different from when the Company would ordinarily schedule the service(s) to be performed, such service(s) will be charged at the applicable overtime rates.

Specific non-gratuitous services:

Holding poles, minimum 4 hours	$~~766.00~~856.00
Each additional hour	~~192.00~~214.00
Line Covering – Primary, minimum 3 hours	~~862.00~~945.00
Each additional hour	~~287.00~~345.00
Line Covering – Secondary, minimum 2 hours	~~356.00~~397.00
Each additional hour	~~178.00~~199.00
Relocate Overhead Loop, minimum 2 hours	~~218.00~~236.00
Each additional hour	~~109.00~~118.00
Connect/Reconnect Loop Charge, minimum 2 hours	~~144.00~~181.00
Each additional hour................................	~~85.00~~90.00
Transformer opening, minimum 1 hour	~~91.00~~97.00
Each additional hour................................	~~91.00~~97.00
To process a check from a customer that is returned to the Company by the bank as not payable..................	15.00

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ELECTRIC RATES

RATE

EARNINGS SHARING ADJUSTMENT

APPLICABILITY

All rate schedules for electric service are subject to an Earnings Sharing (ES) Adjustment. The ES Adjustment amount will be subject to annual changes to be effective beginning August 1 of each year. There shall be a true-up mechanism to the extent necessary to address any over/under recovery issues. The ES Adjustment for all applicable rate schedules is set forth on sheet No. 103A, and will be included in the then current General Rate Schedule Adjustment for billing purposes.

EARNINGS SHARING MECHANISM

The earnings sharing mechanism is used to apply prospective electric rate adjustments for earnings in the prior year over the Company's authorized return on equity (ROE) threshold of 10.00%. The earnings sharing mechanism for earnings in excess of the 10.00% ROE is a follows:

Earned Return on Equity	Sharing Percentages Customers	Sharing Percentages Company
> 10.0% - ≤ 10.2%	60%	40 %
> 10.2% - ≤ 10.5%	50%	50 %
> 10.5%	100%	0 %

Beginning with the 2015 calendar year through 2017, earnings sharing will be measured against a new authorized ROE threshold of 9.83%. The earnings sharing mechanism for earnings in excess of the 9.83% ROE is a follows:

Earned Return on Equity	Sharing Percentages Customers	Sharing Percentages Company
≤ 9.83%	0%	100 %
> 9.83% - ≤ 10.48%	50%	50 %
> 10.48%	100%	0 %

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ELECTRIC RATES | RATE

EARNINGS SHARING ADJUSTMENT

EARNINGS SHARING MECHANISM – Cont'd

As provided in~~In accordance with~~ the Settlement Agreement approved by the Commission in Decision No. C12-0494 in Proceeding~~Docket~~ No. 11AL-947E for 2012 through 2014 and in accordance with the Settlement Agreement approved by the Commission in Decision No. C15-XXXXX in Proceeding No. 14AL-0660E for 2015 through 2017, earnings shall be calculated based on the Company's actual as-booked expenses and weather normalized base rate revenues for the prior year, including revenues from the GRSA as adjusted to remove the effects of any ES and as further adjusted as described below. In the case of the earnings calculation for 2012 through 2014, ~~-~~other regulatory adjustments (including any revenues from the application of the Revenue Loss Adjustment tariff) that may have been in effect during the prior year. For 2014, e~~E~~arnings shall be based on the application of the methodologies and ratemaking principles set forth in Attachment D to the Settlement Agreement entered into in Proceeding No. 11AL-947E. For 2015-2017, earnings shall be based on the application of the methodologies and ratemaking principles set forth in Attachment E to the Settlement Agreement entered into in Proceeding No. 14AL-0660E.

The ES Adjustment will be derived by dividing the amount of the ES Adjustment as derived above by projected weather-normalized revenues over the 12 months the ES Adjustment will be effective.

INFORMATION TO BE FILED WITH THE PUBLIC UTILITIES COMMISSION

Each annual revision to the ES Adjustment will be accomplished by filing an advice letter and will be accompanied by such supporting data and information as the Commission may require from time to time. The Company will file an earnings report on April 30 following each year to which earnings sharing applies, detailing the regulatory electric earnings and any calculated rate reduction to customers' rates.

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EARNINGS SHARING ADJUSTMENT	
The ES adjustment for the period August 1, 2014 through July 31, 2015 shall be negative 3.35 percent. Said adjustment shall be applied as part of the GRSA and shall not apply to charges determined by Non-Base Rate Adjustments or Total Rate Adjustments.	

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ELECTRIC RATES

GENERAL RATE SCHEDULE ADJUSTMENT

The charge for electric service calculated under Company's electric base rate schedules shall be increased by the Rider amount as shown below. Said increase shall not apply to charges determined by Non-Base Rate Adjustments.

RIDER

General Rate Schedule Adjustment (GRSA)	~~17.07~~14.19%
TOTAL:	~~17.07~~14.19%

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ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER N

APPLICABILITY

All rate schedules for electric service are subject to a Clean-Air Clean-Jobs Act Rider (CACJA Rider) designed to recover both the capital and operations and maintenance costs associated with Eligible Clean-Air Clean-Jobs Act Projects in accordance with the Settlement Agreement approved by the Commission in Decision No. C15-XXXX in Proceeding No. 14AL-0660E.

The CACJA Rider for all applicable rate schedules is as set forth on Sheet No. 112E. The CACJA Rider shall be calculated for each service schedule and for customers subscribing for Standby Service.

DEFINITIONS

Clean-Air Clean-Jobs Act (CACJA)
House Bill HB10-1365 required Public Service to work with the Colorado Department of Public Health and Environment to submit a plan to the Public Utilities Commission to reduce nitrogen oxide emissions at Front Range coal plants by 70 to 80 percent by December 31, 2017. The plan, which was approved by the Commission in 2010, includes the retirement of five aging coal plants, their replacement with a new natural gas combined cycle plant, the addition of pollution control equipment at three other coal plants, and the conversion of one coal plant to a natural gas fuel source.

Eligible CACJA Projects
The approved projects included in this CACJA Rider are as follows:

1. Cherokee 5, 6, and 7 -- a natural gas combined cycle (CC) plant, including interconnection equipment.
2. Pawnee selective catalytic reduction and particulate scrubber.
3. Hayden 1 selective catalytic reduction.
4. Hayden 2 selective catalytic reduction.

Eligibility Window: To be eligible to be included in the Rider a cost must be incurred and associated with an investment that went into service between August 1, 2014 and December 31, 2017.

CACJA Revenue Requirement
The forecasted or actual costs associated with Eligible CACJA Projects, including the following:

1. Variable non-fuel Operation and Maintenance (O&M) expenses, including chemical and water expenses. The 2015 CACJA Base Costs will include the variable non-fuel O&M for the existing Cherokee 3 coal unit. After that unit is retired at the end of 2015, subsequent CACJA rider calculations will reflect the variable O&M savings from Cherokee 3's retirement.

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ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER N

DEFINITIONS – Cont’d

CACJA Revenue Requirement – Cont’d

2. Depreciation expense, which will be calculated monthly.
3. State and federal current and deferred income tax expense. This income tax expense shall recognize the impacts of depreciation expense and any other tax deductions including the Domestic production Activities Tax Deduction – Section 199.
4. Return on net plant for projects that have been placed into service, including the accumulated allowance for funds used during construction (AFUDC) for capital expenditures incurred before January 1, 2015.
5. Return on construction work in progress (CWIP) for capital expenditures incurred on or after January 1, 2015.

CACJA Forecasted Revenue Requirements (FRR)

Forecast of the CACJA Revenue Requirement for the subsequent calendar year, based on the best available estimates of capital expenditures, O&M expenses, taxes, and the cost of capital.

CACJA Actual Revenue Requirements (ARR)

The actual CACJA Revenue Requirement for the previous calendar year.

CACJA Rider Revenues (RR)

The actual amount collected from customers in a given year through the CACJA Rider.

Allowance for Funds Used During Construction (AFUDC)

An account that tracks the accumulating costs to the Company to fund large construction projects. The account includes the financing cost of the capital invested in the construction project. These costs are tracked until the project is placed into service, at which point the accumulated AFUDC is included as part of the gross plant placed in service.

Construction Work In Progress (CWIP)

The capital expenditures the Company incurs for a project prior to its in-service date.

Return on CWIP

The Return on CWIP will be the Company’s weighted average cost of capital (WACC) times the average monthly CWIP balance for the relevant period.

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CLEAN-AIR CLEAN-JOBS ACT RIDER N

DEFINITIONS – Cont'd

Weighted Average Cost of Capital (WACC)
The costs of debt and common equity weighted by the relative proportions of each in the Company's balance sheet. For the purpose of developing the FRR, a forecast of the debt cost and capital structure for the following calendar year will be used. For the purpose of developing both the FRR and ARR, the return on equity shall be the latest return on equity approved by the Commission for the Company's electric department.

CACJA Rider True-up
The over-recovery or under-recovery of CACJA costs from two years previous. In 2015 and 2016 the CACJA Rider True-up value shall be $0. The CACJA Rider True-up consists of three components. The first is an adjustment that reconciles the difference between the forecasted revenue requirements (FRR) and the prudently incurred actual revenue requirements (ARR) from two years prior that are demonstrably tied to specific CACJA projects for which the Company has a CPCN. The second component accounts for the difference between the revenues the rider was designed to recover from customers and the actual dollars collected. The third component is an adjustment for interest expenses on the monthly over- or under-recovery from two years prior. For each month the interest component shall be the after-tax WACC applied to the monthly over- or under-collection from the mid-point of the month to the date on which the Company will begin crediting or collecting the over- or under-collection through the CACJA Rider True-up.

CLEAN AIR CLEAN JOBS ACT RIDER AMOUNT

The CACJA Rider Amount shall consist of the current year's Forecasted Revenue Requirement plus the CACJA Rider True-up.

The following formula is used to determine the total annual costs to be collected through the CACJA Rider.

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ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER

N

CLEAN AIR CLEAN JOBS ACT RIDER AMOUNT – Cont'd

CACJA Rider = Forecasted Rev.Req. + True-up1 + True-up_2 + True-up_3
= FFR_y $+(ARR_{y-2}–FRR_{y-2})+(FRR_{y-2}–RR_{y-2})+ Int_{y-2}$

FRR_y = Forecasted CACJA revenue requirements in year 'y', the current year
FRR_{y-2} = Forecasted CACJA revenue requirements in year 'y-2', two years previous
ARR_{y-2} = Actual revenue requirements for CACAJA projects in year 'y-2', two years previous
RR_{y-2} = Actual revenues collected through the CACJA Rider in year 'y-2', two years previous
Int_{y-2} = Accumulated interest expense in year 'y-2', two years previous. Interest shall be calculated monthly by applying the Company's after-tax WACC applied to each months average over or under recovered balance.

The FRR used to set 2015 rates will be $96,968,401.

The True-up component of the 2017 rates will be based on the ARR for the entire year of 2015.

RATE DESIGN

The costs of approved Clean-Air Clean-Job initiatives will be allocated to rate classes based on the production demand allocator approved in the Company's latest Phase II rate case. The allocation factors will be updated based on a projection of energy use by customer class for the forecast year. Rates shall be designed by dividing the costs allocated to each class by the projected class billing determinants. The rates for all years will be based on 12 months of projected class billing determinants. Residential Demand, Secondary General, Primary General, Transmission General, Special Contracts and Standby customers shall be billed the CACJA Rider on a demand basis; all other customers will be billed on an energy basis.

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ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER

N

INFORMATION TO BE FILED WITH THE PUBLIC UTILITIES COMMISSION

Each revision to the CACJA Rider will be accomplished by filing an advice letter no later than November 1st of each year to take effect on the next January 1 and will be accompanied by such supporting data and information as the Commission may require.

The Company shall submit an additional annual filing on or around April 15, 2016, April 15, 2017 and April 15, 2018. In this filing the Company will: discuss the types and levels of expenditures incurred for Eligible CACJA Projects during the previous calendar year; and compare the FRR and ARR for the previous calendar year and explain material deviations. At a minimum, the Company will include in its filing the materials and data consistent with the Settlement reached in Proceeding No. 14AL-0660E.

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ELECTRIC RATES
CLEAN-AIR CLEAN-JOBS ACT RIDER

N

RATE TABLE

Rate Schedule	Applicable Charge	Monthly Rider Rate
Residential Service		
R, RTOU, RPTR, RCPP	Energy Charge	$0.00392/kWh
RD	Demand Charge	0.42/kW-Mo
Small Commercial Service		
C	Energy Charge	0.00387/kWh
NMTR	Energy Charge	0.00387/kWh
Commercial & Industrial General Service		
SGL	Energy Charge	0.01605/kWh
SG, STOU, SPVTOU	Demand Charge	1.28/kW-Mo
PG, PTOU	Demand Charge	1.19/kW-Mo
TG, TTOU	Demand Charge	1.11/kW-Mo
Special Contract Service		
SCS-7	Production Demand Charge	1.19/kW-Mo
Standby Service		
SST	Gen & Trans Standby Capacity Reservation Fee	0.15/kW-Mo
	Usage Demand Charge	1.13/kW-Mo
PST	Gen & Trans Standby Capacity Reservation Fee	0.14/kW-Mo
	Usage Demand Charge	1.05/kW-Mo
TST	Gen & Trans Standby Capacity Reservation Fee	0.13/kW-Mo
	Usage Demand Charge	0.98/kW-Mo
Lighting Service		
RAL, CAL, PLL, MSL, ESL, SL, SSL, COL, SLU	Energy Charge	0.00192/kWh
TSL, MI	Energy Charge	0.00192/kWh

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ELECTRIC RATES
TRANSMISSION COST ADJUSTMENT

APPLICABILITY

All rate schedules for electric service are subject to a Transmission Cost Adjustment (“TCA”) rider to reflect the ongoing capital costs associated with transmission investment that are not being recovered through the Company’s base rates. The TCA amount will be subject to annual changes to be effective on January 1 of each year. The TCA to be applied to each rate schedule is as set forth on Sheet No. 109B.

DEFINITIONS

Over/Under Recovery Amount – The Over/Under Recovery Amount is the balance, positive or negative, of TCA revenues received less the Transmission Cost intended to be recovered each year through the rider.

True-Up Amount – The True-Up Amount is equal to the difference, positive or negative, between the Transmission Cost, calculated based on the projected net transmission plant and transmission CWIP balances, and the Transmission T
Cost calculated based on the actual net transmission plant and transmission T
CWIP balances.

If any projects included in the year-end CWIP balance were placed in N
service sometime during the subsequent year when the TCA was effective, N
then the CWIP balance will be reduced accordingly. Specifically, the N
component of the year-end CWIP balance attributable to any such project N
will be reduced by the following: N
Year-End Project CWIP Balance X (Number of Months Project Was in N
Service During Subsequent Year / 13) N

Transmission Cost – For the purpose of this tariff, the Transmission Cost is defined as (1) a return, equal to the Company’s weighted average cost of capital, on the projected increase in the retail jurisdictional portion of the thirteen month average net transmission plant for the year in which the TCA will be in effect; (2) the plant-related ownership costs associated T
with such incremental transmission investment, including depreciation, accumulated deferred income taxes, income taxes and pre-funded AFUDC, and (3) a return, equal to the Company’s weighted average cost of capital, on the projected year-end transmission construction work in progress (“CWIP”) balance as of December 31 of the year immediately preceding the effective C
date of the TCA. C

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ELECTRIC RATES
TRANSMISSION COST ADJUSTMENT

DEFINITIONS – Cont'd

If any projects included in the year-end CWIP balance are projected to be placed in service sometime during the subsequent year when the TCA will be effective, then the CWIP balance will be reduced accordingly. Specifically, the component of the year-end CWIP balance attributable to any such project will be reduced by the following: N N N N N N N

Year-End Project CWIP Balance X (Number of Months Project Will Be in Service During Subsequent Year / 13)

Transmission Cost Adjustment - The Transmission Cost Adjustment is equal to the Transmission Cost, plus, beginning with the second year of the rider, the True-Up Amount and, beginning with the third year of the rider, the Over/Under Recovery Amount, charged on a dollar per kilowatt basis for tariff schedules with demand rates and on a dollar per kilowatt-hour basis for tariff schedules without demand rates. M M M M M M

INFORMATION TO BE FILED WITH THE PUBLIC UTILITIES COMMISSION

Each proposed revision in the Transmission Cost Adjustment will be accomplished by filing an advice letter on November 1 of each year to take effect on the next January 1 and will be accompanied by supporting data and information as set forth in Ordering Paragraph No. 6 of Decision No. C07-1085.

TCA ADJUSTMENT WITH CHANGES IN BASE RATES

Whenever 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.

INTEREST CALCULATION UNDER A TRUE UP

Over collections of rider revenues that are due to over projections of net plant and CWIP balances shall be assessed interest as part of the true-up mechanism in the TCA. To determine an over collection of rider revenues due to over projections of net plant and CWIP, the revenue requirements associated with the projected net plant in service and CWIP shall be compared to the revenue requirements associated with the actual net plant in service and CWIP for that same year. Interest is only assessed on the positive balance of rider revenues calculated on projected plant in service and CWIP compared to the calculated rider revenues based on actual plant in service and CWIP over the same time period. Interest shall be calculated at the after taxes weighted average cost of capital.

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ELECTRIC RATES
TRANSMISSION COST ADJUSTMENT

RATE TABLE

Rate Schedule	Applicable Charge	Monthly Rider Rate	
Residential Service			
R, RTOU, RPTR, RCPP	Energy Charge	$0.00063 /kWh	R
RD	Demand Charge	$ 0.07 /kW-Mo	R
Small Commercial Service			
C	Energy Charge	$ 0.00062 /kWh	R
NMTR	Energy Charge	$ 0.00062 /kWh	R
Commercial & Industrial General Service			
SGL	Energy Charge	$ 0.00258 /kWh	R
SG, STOU, SPVTOU	Demand Charge	$ 0.21 /kW-Mo	R
PG, PTOU	Demand Charge	$ 0.20 /kW-Mo	R
TG, TTOU	Demand Charge	$ 0.18 /kW-Mo	R
Special Contract Service			
SCS-7	Production Demand Charge	$ 0.20 /kW-Mo	R
Standby Service			
SST	Gen & Trans Standby Capacity Reservation Fee	$ 0.02 /kW-Mo	R
	Usage Demand Charge	$ 0.19 /kW-Mo	R
PST	Gen & Trans Standby Capacity Reservation Fee	$ 0.02 /kW-Mo	R
	Usage Demand Charge	$ 0.18 /kW-Mo	R
TST	Gen & Trans Standby Capacity Reservation Fee	$ 0.02 /kW-Mo	R
	Usage Demand Charge	$ 0.16 /kW-Mo	R
Lighting Service			
RAL, CAL, PLL, MSL, ESL, SL, SSL, COL, SLU	Energy Charge	$ 0.00032/kWh	R
TSL, MI	Energy Charge	$ 0.00032/kWh	R

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ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

APPLICABILITY

All rate schedules for electric service are subject to an Electric Commodity Adjustment (ECA) to reflect the cost of energy utilized to supply electric service. The Electric Commodity Adjustment Factors for all applicable rate schedules are as set forth on Sheet No. 111H and will be T applied to all kilowatt-hours sold by the Company with the exception of any buy-through kilowatt-hours (BT kWh) sold to participants in the Interruptible Service Option Credit (ISOC) program who buy through an Economic Interruption. The ECA Factors for lighting service bills and other non-metered service will be determined by applying the ECA Factor to the calculated monthly kilowatt-hour consumption.

TIME-OF-USE ECA FACTORS APPLICABILITY

All kilowatt-hours used under any Rate Schedule for Commercial and Industrial Primary, Transmission or Special Contract Service customers shall be billed under the appropriate Time-of-Use ECA Factor. Customers that receive electric service under any Commercial and Industrial Secondary Service Rate Schedule that have measured demands of three hundred kilowatt (300 kW) or more for twelve (12) consecutive months may elect to be billed prospectively under the Secondary Time-of-Use ECA Factor. Subsequent to a customer's election to be billed under the Secondary Time-of-Use ECA Factor, customer must have a measured demand of three hundred kilowatts (300 kW) or more every month, except a customer may have one month within the previous twelve (12) months where the customer demand is less than three hundred kilowatts (300 kW). In the event that a second month occurs in any twelve month period where the customer's measured demand is less than three hundred kilowatts (300 kW), the Company shall bill the customer under the non-Time-of-Use Secondary ECA Factor.

The On-peak hours shall be 9:00 AM to 9:00 PM for all non-holiday weekdays. Holidays are defined as New Years Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. The Off-peak period shall be all other hours. The On-peak and Off-peak price differentials are based on the ratio of system marginal costs for a calendar year. The On-peak and Off-peak price ratio will be projected annually and will be filed with the Commission on the first business day of November, and shall remain in effect for the subsequent calendar year. The TOU ECA rates will be updated with the Quarterly ECA rates and will be determined by applying the fixed annual On-peak and Off-peak ratios to the quarterly ECA cost of service.

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ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

TIME-OF-USE NOTICE AND METERING REQUIREMENTS

Customers receiving service under the Time-of-Use ECA must have their usage metered by an Interval Data Recorder (“IDR”) meter. If a requesting customer is not currently metered with an IDR meter the Company will install an IDR meter as soon as reasonably practicable and the customer will be eligible for the Time-of-Use rate beginning with the first billing cycle immediately subsequent to the installation of the IDR meter.

ELECTRIC COMMODITY ADJUSTMENT QUARTERLY FILING

The Company shall file each quarter, on not less than fifteen (15) days notice, an application with the ECA Factors on Sheet No. 111H to be effective on the first day of the month of the next calendar quarter. The Company may also file for more frequent changes to the ECA factors, subject to Commission Approval. T

ELECTRIC COMMODITY ADJUSTMENT

The ECA shall be calculated quarterly with the new ECA Factors to be effective on a prorated basis on the first day of the quarter. The ECA Factors shall be determined by dividing the Quarterly ECA Revenue Requirement by the projected kilowatt-hour sales to which the ECA is applicable for the next calendar quarter. The ECA Factors shall be differentiated by service delivery voltage to reflect line losses.

LOSS FACTOR

The ECA Factors take into account service delivery voltage to reflect line losses. Loss Factors are as follows:

Transmission	1.0000
Primary	1.0235
Secondary	1.0500

Primary and Secondary voltage losses may be updated by the Company from time to time.

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ELECTRIC RATES
ELECTRIC COMMODITY ADJUSTMENT

ELECTRIC COMMODITY ADJUSTMENT – Cont'd

8) NGS Balance shall be the total cost for the sales of natural gas less the natural gas sales credit for all revenue received by the Company for the sale of natural gas to Southwest Generation for their Fountain Valley Facility.

The ECA revenue collected for the quarter will be adjusted for billing cycle lag.

Interest shall accrue monthly on the average monthly deferred balance (whether the balance is positive or negative). The monthly interest rate shall be at a rate equal to the average of the daily rates for Commercial Paper, Financial, 3-Month rates, published by the United States Federal Reserve H.15 report (http://www.federalreserve.gov/releases/h15/data.htm).

ADJUSTMENT FOR SHORT-TERM SALES MARGIN

Positive short-term sales margins from the calendar year shall be shared with retail customers through an adjustment to the ECA. Margin sharing shall be calculated separately for both the Generation Book margins and Proprietary Book margins. Proprietary Book margins shall be calculated from the Company's share of margins under the Joint Operating Agreement. Within each of these books, the retail jurisdictional Gross Margin shall be aggregated annually. If the aggregated Gross Margin from either book is negative, the negative margin shall not be passed on to retail customers.

If the annual retail jurisdictional aggregated Gross Margin in either book is positive, then such positive annual retail jurisdictional Gross Margin shall be shared annually with retail customers through the ECA as follows:

1) Generation Book: Gross Margin in excess of $678,027 for calendar T
year 2015 and subsequent years shall be shared ninety percent (90%) T
retail customers/ten percent (10%) Company.

2) Proprietary Book: Gross Margin in excess of $514,659 for calendar T
year 2015 and subsequent years shall be shared ten percent (10%) retail T
customers/ninety percent (90%) Company.

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ELECTRIC COMMODITY ADJUSTMENT

ADJUSTMENT FOR SHORT-TERM SALES MARGIN – Cont'd

The Company shall include in its quarterly filing for effect April 1 of each year a report setting forth the retail customer share of positive short-term sales margins from the prior calendar year. The total positive short-term sales margins will be divided by three (3), and the quotient shall be subtracted from each quarterly ECARR for the remainder of the calendar year.

ADJUSTMENT FOR SO_2 ALLOWANCE MARGINS

Margins earned from the sale of SO_2 allowances by the Company shall be shared with retail customers in accord with Commission orders. The Company shall include in its quarterly filing for effect April 1 of each year a report setting forth the retail customer share of the SO_2 allowance margins from the prior calendar year. The margins to be shared will be divided by three (3), and the quotient shall be subtracted from each quarterly ECARR for the remainder of the calendar year.

PUEBLO INCENTIVE PROPERTY TAX CREDIT

An adjustment shall be made to the Deferred Account Balance to include the flow-through to customers of the amount of any incentive property tax credit or payment received by the Company from the City of Pueblo or Pueblo County pursuant to agreements entered into by the Company with the City of Pueblo and Pueblo County in 2005, commencing with incentive property tax credits or payments attributable to property taxes payable for tax year 2012. As to each regular quarterly ECA application, the adjustment to the applicable Deferred Account Balance shall include all such incentive property tax credits and payments received by the Company during the quarterly period ending as of the last day of the calendar month immediately preceding the date of the ECA application.

ADJUSTMENT FOR TRUE-UP OF COSTS BETWEEN THE RESA AND ECA

An adjustment shall be made to the ECA Deferred Account Balance to collect the component of costs that were charged to the Renewable Energy Standard Adjustment ("RESA") that should have been charged to the ECA for the period 2010 – 2012. An adjustment to the ECA Deferred Account Balance shall commence beginning with the subsequent month after the Company receives Commission approval of said adjustment and shall be collected in the ECA Deferred Account Balance equally over a period of twelve months.

EQUIVALENT AVAILABILITY FACTOR PERFORMANCE MECHANISM N

The Equivalent Availability Factor Performance Mechanism ("EAFPM") will apply only to the Company's performance in calendar years 2015, 2016 and 2017. An adjustment shall be made to the Deferred Account Balance to include the incentive or penalty attributable to the EAFPM for performance in 2015, 2016 and 2017. N N N N N N N

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ELECTRIC COMMODITY ADJUSTMENT

EQUIVALENT AVAILABILITY FACTOR PERFORMANCE MECHANISM - CONT'D N

The Company shall file on or before April 1, 2016, April 1, 2017, and April 1, 2018, a report detailing the results of the EAFPM for the previous calendar year and requesting through an Application Commission approval of an adjustment as applicable to the ECA Deferred Account Balance. Once a final Commission Decision has been issued on the Company's Application, the total amount of the approved incentive or penalty will be included in the subsequent quarterly filing. N

For calendar years 2015, 2016 and 2017, the Company shall calculate the Current Year Weighted Average EAF for the Eligible Units. N

If the Current Year Weighted Average EAF for calendar year 2015 is at or above 86.19%, then the Company will earn a before-tax incentive of $3 million. If the Current Year Weighted Average EAF for calendar year 2015 is at or below 83.79%, then the Company will be assessed a before-tax penalty of $3 million. If the Current Year Weighted Average EAF for calendar year 2015 falls between 83.79% and 86.19%, then the Company will neither earn an incentive nor be assessed a penalty. N

If the Current Year Weighted Average EAF for calendar year 2016 or calendar year 2017 is at or above 86.57%, then the Company will earn a before-tax incentive of $3 million. If the Current Year Weighted Average EAF for calendar year 2016 is at or below 84.49%, then the Company will be assessed a before-tax penalty of $3 million. If the Current Year Weighted Average EAF for calendar year 2016 falls between 84.49% and 86.57%, then the Company will neither earn an incentive nor be assessed a penalty. N

The Company shall exclude the following circumstances from the Current Year EAF calculation: N

1.) Outage events that are classified as Outside Management Control in the Generating Availability Data System ("GADS"). N
2.) All outage events that are specifically attributable to an order from a state or federal regulatory agency or an adopted state or federal law. N

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ELECTRIC COMMODITY ADJUSTMENT

EQUIVALENT AVAILABILITY FACTOR PERFORMANCE MECHANISM - CONT'D N

For purposes of this Equivalent Availability Factor Incentive Mechanism section, the following definitions will apply: N N

Eligible Units for 2015. Cherokee 4, Comanche 1-3, Hayden 1-2, Pawnee, Fort St. Vrain 1-4 and Rocky Mountain Energy Center 1-3. N N

Eligible Units for 2016 and 2017. Cherokee 4-7, Comanche 1-3, Hayden 1-2, Pawnee, Fort St. Vrain 1-4 and Rocky Mountain Energy Center 1-3. N N

Equivalent Availability Factor ("EAF"). The total number of available hours for the specified time period minus the equivalent derated hours, both planned, unplanned and seasonal, and then divided by the number of hours in the same period. The result is then multiplied by 100 percent. The EAF shall be calculated consistent with the North American Electric Reliability Corporation requirements as reported in GADS. N N N N N N N

Current Year Weighted Average EAF. The average of the EAFs of the Eligible Units in the current year, weighted by the Net Maximum Capacity of the Eligible Units. N N N

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ELECTRIC RATES

ELECTRIC COMMODITY ADJUSTMENT

ECA FACTORS FOR THE FIRST QUARTER OF 2015

ECA Factors for Billing Purposes M

Residential, applicable to all kilowatt-hours used under any Rate Schedule for Residential Service	$0.03340/kWh	R
Small Commercial and Non-Metered, applicable to all kilowatt-hours used under any Rate Schedules for Small Commercial Service and Non-Metered Service	$0.03340/kWh	R
Commercial and Industrial Service at Secondary Voltage applicable to all kilowatt-hours used under any Rate Schedules for Commercial and Industrial Secondary Service Rate Schedules for Commercial and Industrial Service	$0.03340/kWh	R
Optional Time-of-Use Off-Peak	$0.02770/kWh	R
On-Peak to Off-Peak Ratio	1.48	R
Optional Time-of-Use On-Peak	$0.04100/kWh	R
Commercial and Industrial Service at Primary Voltage, applicable to all kilowatt-hours used under any Rate Schedules for Commercial and Industrial Primary or Special Contract Service		
Mandatory Time-of-Use Off-Peak	$0.02751/kWh	R
On-Peak to Off-Peak Ratio	1.48	R
Mandatory Time-of-Use On-Peak	$0.04071/kWh	R
Commercial and Industrial Service at Transmission Voltage, applicable to all kilowatt-hours used under any Rate Schedules for Commercial and Industrial Transmission Service		
Mandatory Time-of-Use Off-Peak	$0.02711/kWh	R
On-Peak to Off-Peak Ratio	1.48	R
Mandatory Time-of-Use On-Peak	$0.04012/kWh	R
Lighting, applicable to all kilowatt-hours used under any Rate Schedule for Commercial Lighting or Public Street Lighting Service	$0.03340/kWh	R

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ELECTRIC RATES	RATE	
ELECTRIC SERVICE		
MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE		
Under this schedule, the Company will specifically bill the customer for all maintenance and replacement of street lighting facilities, other than what is provided under each lighting service schedule, in accordance with the following rates, percentages, and general criteria.		
Labor		
For work performed during normal working hours, per man-hour..	$57.00	I
For work performed during hours other than normal working hours, and except for Sundays and holidays, per man-hour..	94.00	I
For work performed on Sundays and holidays, per man hour..	112.00	R
Materials		
Stores Overhead Percentage............................	9.04%	
The above percentage will be applied to and then added to the Company's individual materials costs to develop the total materials charge. Individual materials costs will be charged on a current actual cost basis and will be subject to change without notice.		
Vehicles		
1/2 Ton Pick-up Truck (12 Series):		
Per Hour	8.23	R
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ELECTRIC RATES	RATE	
ELECTRIC SERVICE		
MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE		
Vehicles - Cont'd		
3/4 or 1 Ton Truck, Special Body, 6,200-9,600 GVW (18 Series) Per Hour	$ 11.83	I
1 Ton Truck, Special Body, 10,000-16,000 GVW (20 Series): Per Hour	17.92	I
Utility Truck (21 Series): Per Hour	14.54	R

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ELECTRIC RATES	RATE	
ELECTRIC SERVICE		
MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE		
Vehicles - Cont'd		
Welding Truck (26 Series): Per Hour	$ 11.74	I
Line Center Mount Truck (30 Series): Per Hour	19.41	I
2 Ton Truck (31 Series): Per Hour	30.44	
Boom Truck (32 Series): Per Hour	21.90	R
35 Foot One-man Bucket Truck (33 Series): Per Hour	20.04	I
40 Foot One-man Bucket Truck (34 Series): Per Hour	21.33	R
50 Foot One-man Bucket Truck (35 Series): Per Hour	15.96	R
85 Foot and Higher Two-man Bucket Truck (37 Series): Per Hour	35.09	R

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ELECTRIC RATES	RATE	
ELECTRIC SERVICE		
MAINTENANCE CHARGES FOR STREET LIGHTING SERVICE		
Vehicles - (Cont'd)		
Dump Truck (38 Series): Per Hour	$ 20.93	R
Trencher (44 Series): Per Hour	11.45	R
Earthboring Machine, Truck or Trailer Mounted (46 Series): Per Hour	100.00	
Portable Welder or Air Compressor (58 Series): Per Hour	6.83	I
Multiple Axle Trailer (61 Series): Per Hour	4.81	I
Backhoe (62 Series): Per Hour	15.53	
Misc. Boring & Restoration Truck (63 Series): Per Hour	37.57	
Misc. Boring & Restoration Equipment (64 Series): Per Hour	23.97	

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ELECTRIC RATES	RATE	
ELECTRIC SERVICE		
SCHEDULE OF CHARGES FOR RENDERING SERVICE		
To institute or reinstitute electric service requiring a premise visit within:		
24 hours	$ 38.00	I
12 hours	77.00	I
To institute or reinstitute both gas and electric service requiring a premise visit within:		
24 hours	96.00	R
12 hours	132.00	R
To provide a non-regularly scheduled final meter Reading at customers request	24.00	
To transfer service at a specific location from one customer to another customer where such service is continuous, either electric service or both electric and gas service at the same time not requiring a premise visit	8.00	
To perform non-gratuitous labor for service work, not specified below, (not including appliance repair and premium power) in addition to charges for materials, is as follows:		
Trip Charge	40.00	I
(Assessed when no actual service work is performed, other than a general diagnosis of the customer's problem)		
For service work during normal working hours per man-hour	75.62	I
Minimum Charge, one hour	75.62	I
An overtime rate will be applicable to non-gratuitous labor for service work performed before and after normal working hours of 8:00 AM to 5:00 PM Monday through Saturday. The overtime rate shall be, per man-hour	94.26	I
Minimum Charge, one hour	94.26	I

(Continued on Sheet No. 25A)

COLO. PUC No. 7 Electric

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 25A

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ELECTRIC RATES	RATE	
ELECTRIC SERVICE		
SCHEDULE OF CHARGES FOR RENDERING SERVICE		
When such service work is performed on Sundays and holidays, per man hour	112.90	I
Minimum Charge, one hour	112.90	I
When customer requests one or more of the specific non-gratuitous services listed below to be performed at a time specified by the customer that is different from when the Company would ordinarily schedule the service(s) to be performed, such service(s) will be charged at the applicable overtime rates.		
Specific non-gratuitous services:		
Holding poles, minimum 4 hours	$856.00	I
Each additional hour	214.00	I
Line Covering – Primary, minimum 3 hours	945.00	I
Each additional hour	345.00	I
Line Covering – Secondary, minimum 2 hours	397.00	I
Each additional hour	199.00	I
Relocate Overhead Loop, minimum 2 hours	236.00	I
Each additional hour	118.00	I
Connect/Reconnect Loop Charge, minimum 2 hours	181.00	I
Each additional hour...............................	90.00	I
Transformer opening, minimum 1 hour	97.00	I
Each additional hour...............................	97.00	I
To process a check from a customer that is returned to the Company by the bank as not payable..................	15.00	

(Continued on Sheet No. 25B)

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Sheet No.

ELECTRIC RATES | RATE

EARNINGS SHARING ADJUSTMENT

APPLICABILITY

All rate schedules for electric service are subject to an Earnings Sharing (ES) Adjustment. The ES Adjustment amount will be subject to annual changes to be effective beginning August 1 of each year. There shall be a true-up mechanism to the extent necessary to address any over/under recovery issues. The ES Adjustment for all applicable rate schedules is set forth on sheet No. 103A, and will be included in the then current General Rate Schedule Adjustment for billing purposes.

EARNINGS SHARING MECHANISM

The earnings sharing mechanism is used to apply prospective electric rate adjustments for earnings in the prior year over the Company's authorized return on equity (ROE) threshold of 10.00%. The earnings sharing mechanism for earnings in excess of the 10.00% ROE is a follows:

	Sharing Percentages	
Earned Return on Equity	Customers	Company
> 10.0% - ≤ 10.2%	60%	40 %
> 10.2% - ≤ 10.5%	50%	50 %
> 10.5%	100%	0 %

Beginning with the 2015 calendar year through 2017, earnings sharing will be measured against a new authorized ROE threshold of 9.83%. The earnings sharing mechanism for earnings in excess of the 9.83% ROE is a follows: N N N N

	Sharing Percentages		
Earned Return on Equity	Customers	Company	N
≤ 9.83%	0%	100 %	N
> 9.83% - ≤ 10.48%	50%	50 %	N
> 10.48%	100%	0 %	N

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COLO. PUC No. 7 Electric

PUBLIC SERVICE COMPANY OF COLORADO

Sheet No. 103A

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ELECTRIC RATES | RATE

EARNINGS SHARING ADJUSTMENT

EARNINGS SHARING MECHANISM – Cont'd

As provided in the Settlement Agreement approved by the Commission in Decision No. C12-0494 in Proceeding No. 11AL-947E for 2012 through 2014 and in accordance with the Settlement Agreement approved by the Commission in Decision No. C15-XXXXX in Proceeding No. 14AL-0660E for 2015 through 2017, earnings shall be calculated based on the Company's actual as-booked expenses and weather normalized base rate revenues for the prior year, including revenues from the GRSA as adjusted to remove the effects of any ES and as further adjusted as described below. In the case of the earnings calculation for 2012 through 2014, other regulatory adjustments (including any revenues from the application of the Revenue Loss Adjustment tariff) that may have been in effect during the prior year. For 2014, earnings shall be based on the application of the methodologies and ratemaking principles set forth in Attachment D to the Settlement Agreement entered into in Proceeding No. 11AL-947E. For 2015-2017, earnings shall be based on the application of the methodologies and ratemaking principles set forth in Attachment E to the Settlement Agreement entered into in Proceeding No. 14AL-0660E. C C C C C C C C C C C C C C C C C C C C C

The ES Adjustment will be derived by dividing the amount of the ES Adjustment as derived above by projected weather-normalized revenues over the 12 months the ES Adjustment will be effective. M M M M

INFORMATION TO BE FILED WITH THE PUBLIC UTILITIES COMMISSION
Each annual revision to the ES Adjustment will be accomplished by filing an advice letter and will be accompanied by such supporting data and information as the Commission may require from time to time. The Company will file an earnings report on April 30 following each year to which earnings sharing applies, detailing the regulatory electric earnings and any calculated rate reduction to customers' rates. M M M M M M M M

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COLO. PUC No. 7 Electric

PUBLIC SERVICE COMPANY OF COLORADO

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ELECTRIC RATES | RATE

EARNINGS SHARING ADJUSTMENT

The ES adjustment for the period August 1, 2014 through July 31, 2015 shall be negative 3.35 percent. Said adjustment shall be applied as part of the GRSA and shall not apply to charges determined by Non-Base Rate Adjustments or Total Rate Adjustments. M M N M N

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PUBLIC SERVICE COMPANY OF COLORADO

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ELECTRIC RATES

GENERAL RATE SCHEDULE ADJUSTMENT

The charge for electric service calculated under Company's electric base rate schedules shall be increased by the Rider amount as shown below. Said increase shall not apply to charges determined by Non-Base Rate Adjustments.

RIDER

General Rate Schedule Adjustment (GRSA)	14.19%	R
TOTAL:	14.19%	R

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