EXHIBIT NO. ___(KJB-1T)
DOCKET NO. UE-14____
2014 PSE PCORC
WITNESS: KATHERINE J. BARNARD

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-14________**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
KATHERINE J. BARNARD
ON BEHALF OF PUGET SOUND ENERGY, INC.

MAY 23, 2014

PUGET SOUND ENERGY, INC.

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy, Inc.

A. My name is Katherine J. Barnard. My business address is 10885 NE 4th Street, Bellevue, Washington, 98009-5591. I am Director, Revenue Requirements and Regulatory Compliance with Puget Sound Energy, Inc. ("PSE").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(KJB-2).

Q. What is the nature of your testimony in this proceeding?

A. My testimony describes adjustments for changes in PSE's power supply costs that are included in the proposed Power Cost Baseline Rate ("Baseline Rate"), including the rate impact of: (1) new resources such as the Centralia Coal Transition Power Purchase Agreement ("Coal Transition PPA"); (2) updates to the Lower Baker and Snoqualmie Falls hydroelectric redevelopment projects; and (3) Treasury Grants for the Snoqualmie Falls and Baker hydroelectric plant capital upgrades. In addition, I present a proposal for recovery of the incremental costs associated with contract changes in price and volume for the Coal Transition PPA, as they occur, and I update resource expenses to account for current costs and expected power costs.

The total rate decrease resulting from these adjustments is $9,556,193 an average 0.456 percent decrease over the rates set in PSE's 2013 Power Cost Only Rate Case ("PCORC") in Docket No. UE-130617.

II. ADJUSTMENTS TO THE POWER COST BASELINE RATE

Q. Please explain what is meant by the Power Cost Baseline Rate.

A. The Baseline Rate is a product of the parties' settlement of PSE's 2001 general rate case, Docket Nos. UE-011570 and UG-011571. In June 2002, the Commission approved the Settlement Stipulation for Electric and Common Issues in that docket ("2001 GRC Settlement Stipulation"). *See* Commission's Twelfth Supplemental Order (June 20, 2002) ("Twelfth Supplemental Order"). Among other things, the Twelfth Supplemental Order authorized the use of a Power Cost Adjustment mechanism ("PCA") as a method for adjusting PSE's power costs. *See Settlement Terms for the Power Cost Adjustment Mechanism*, Exhibit A to the 2001 GRC Settlement Stipulation, attached as the Second Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(KJB-3).

As described in the 2001 GRC Settlement Stipulation, the PCA sets forth an annual accounting process for a sharing of costs and benefits between PSE and its customers over four graduated levels, or "bands," of power cost variances.[1] *See* Exhibit No. ___(KJB-3) at page 1. The PCA distinguishes between power costs and all other costs included in general rates and allows PSE to file an application

[1] The PCA had an overall cap on PSE's share of power cost variances of $40 million (+/-) over the four year period July 1, 2002 through June 30, 2006, which is now expired.

seeking adjustment to all of PSE's power costs identified in the Baseline Rate. *See* Exhibit No. ___(KJB-3) at page 3. The 2001 GRC Settlement Stipulation includes a table that shows the allocation of costs between costs that can be adjusted through the PCA, and other, non-power costs, which are not adjusted through the PCA. Two categories of costs comprise the Baseline Rate: variable rate components and fixed rate components. *See* Exhibit No. ___(KJB-3) at page 4.

Q. Have there been changes to the PCA and the method of determining the Baseline Rate since the 2001 GRC Settlement Stipulation was approved by the Commission?

A. Yes. Several changes have been made to the PCA since the 2001 GRC Settlement Stipulation was approved by the Commission. These include:

(i) revising the accounting period for the PCA accounting process to a calendar year;[2]

(ii) eliminating Schedule E;[3]

(iii) including interest costs and commitment fees associated with electric hedging activities in the Power Cost Baseline Rate;[4]

(iv) Rate spread is computed using the peak credit results from PSE's most recent general rate case proceeding rather than the methodology used in the 2001 general rate case;[5]

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[2] Docket UE-050870

[3] Docket UE-060266

[4] Docket UE-060266

[5] Docket UE-070565

(v) extending the expected procedural schedule for a PCORC from five to six months;[6]

(vi) limiting the filing of power cost updates to one per PCORC, with an additional update allowed as part of the compliance filing if the Commission determines the update is necessary due to changes in gas costs and orders that such update be made as part of the compliance filing;[7]

(vii) prohibiting the overlap of PCORC and general rate cases, except for requests for interim rate relief;[8]

(viii) shortening PCORC data request response time from ten to five business days at the outset.[9]

(ix) a temporary waiver of the requirement to file a general rate case within three months after issuance of the final order in a PCORC.[10]

(x) removal of property taxes from the PCA mechanism.[11]

Q. Are there efforts currently underway to review the existing PCA mechanism and PCORC?

A. Yes. As a result of the settlement in the 2013 PCORC[12] ("2013 PCORC Settlement Stipulation"), PSE, Commission Staff, Public Counsel and the Industrial Customers of Northwest Utilities ("collaborative parties") have been engaged in a collaborative process per WAC 480-07-720 to address PCA and PCORC-related issues ("PCA/PCORC collaborative"). Under the 2013 PCORC

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6 Docket UE-072300

7 *Id.*

8 *Id.*

9 *Id.*

10 Paragraph 194 in Order No. 07 in Docket UE-130137 and UG-130138.

11 Docket UE-130617.

12 The 2013 PCORC settlement was adopted by reference as Appendix A to Order No. 06 in Docket UE-130617 – Final Order Approving and Adopting Settlement Agreement.

Settlement Stipulation, if the parties reached an agreement in the collaborative, they would propose implementation of the agreed upon changes in this PCORC. If the parties did not reach agreement in the collaborative, PSE would initiate a new docket by July 1, 2014, to address outstanding issues. An additional collaborative to address rate spread and rate design issues is also currently ongoing and is discussed in more detail in the Prefiled Direct Testimony of Mr. Jon A. Piliaris, Exhibit No. ___(JAP-1T).

Q. Has there been any agreement reached in the PCA/PCORC collaborative?

A. No. While the collaborative parties have met several times between November 2013 and May 2014, they were not able to reach substantive resolution on any of the issues that were identified in the PCA/PCORC collaborative.

Q. How have the collaborative parties decided to address the unresolved issues?

A. The parties are continuing to consider proposals relating to the PCA/PCORC, and have agreed to ask the Commission to allow the scheduled July 1, 2014 filing to be postponed until October 1, 2014, to allow more time for analysis of proposals.

Q. Continuing with your discussion of the existing PCA mechanism, when are the accumulated PCA costs and benefits allocations reviewed?

A. PSE files an annual PCA compliance report in March of each year that details the power costs included in the deferral calculation for the annual period ending December 31 of the prior year.

Q. How is the Power Cost Baseline Rate adjusted?

A. Independent of the yearly accounting and adjustment for power cost variances, PSE may also apply to the Commission to true up the Power Cost Baseline Rate to all power costs identified in a PCORC. In order to true up the Baseline Rate, the 2001 GRC Settlement Stipulation requires, among other things, testimony and exhibits that include

- Adjustments to the fixed rate components of the Baseline Rate;
- Adjustments to the variable rate components of the Baseline Rate; and
- A calculation of pro forma production cost schedules that are consistent with the costs presented with PSE's most recent general rate case, including power supply and other adjustments impacting production costs.

My testimony provides this required information in support of PSE's present application to true up its Power Cost Baseline Rate through this PCORC.

Q. Would you please describe the adjustments used to determine the new Baseline Rate?

A. The Third Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(KJB-4), summarizes the adjustments used to determine the new Power Cost Baseline Rate. As stated earlier, the PCA makes a distinction between: (i) power costs, as determined in a PCORC; and (ii) all the other costs included in general rates. In both a general rate case and a PCORC, PSE uses a future rate year to determine certain power costs and then pro forms those costs back to the test year. Using such methodology for this proceeding, PSE summarized the power cost adjustments, plus restating adjustments, associated with production costs in Exhibit No. ___(KJB-4)**.** The proposed rate year used for these adjustments is December 2014 through November 2015. As was agreed to in the 2013 PCORC Settlement Stipulation, the test year is the period January 1, 2013 through December 31, 2013 (the "test year")[13].

In addition to the above power cost adjustments, a pro forma adjustment has been made to account for the equity adder on the Coal Transition PPA, as authorized by the Commission in Docket UE-121373, *In re Petition of Puget Sound Energy, Inc. for Approval of a Power Purchase Agreement for Acquisition of Coal Transition Power, as Defined in RCW 80.80.010, and the Recovery of Related Acquisition Costs*. A separate equity return variable line item has been added to the Baseline Rate for this item. I will also propose a method to recover the incremental power costs and equity adder associated with the contracted volume and price increases included in the Coal Transition PPA for periods beyond this proceeding's rate year, as instructed by the Commission in Order 8 in the above referenced docket.[14]

Finally, regulatory and ratemaking treatment related to the pending sale of the Electron project have not been included in the Baseline Rate but will be updated should the pending sale progress by the time of a supplemental update for this proceeding. The status of the pending sale is discussed in the Prefiled Direct Testimony of Mr. Paul K. Wetherbee, Exhibit No. ___(PKW-1T).

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[13] Paragraph 32 in Final Order No. 06 in Docket No. UE-130617.

[14] Docket UE-121373 WUTC Order 08 on Reconsideration at page 29, paragraph 56.

Q. Please explain what Exhibit No. ___(KJB-4) represents.

A. The first column of Exhibit No. ___(KJB-4), titled "Test Year Actual 12 months ended December 31, 2013," shows the rate base and production costs from the test year that will be considered in setting the Power Cost Baseline Rate. The columns to the right of this first column show the impact of the pro forma and restating production cost adjustments PSE is proposing for the pro forma rate year. These adjustments are presented in more detail on the succeeding pages referenced in the title of a particular column. The work papers supporting these adjustments have been provided to WUTC Staff and intervenors. The total of the test year amounts plus the pro forma and restating adjustments is shown in the column titled "Adjusted 12 months ended December 31, 2013" on page 3 of Exhibit No. ___(KJB-4). This column represents the costs to be used in determining the Power Cost Baseline Rate, which in turn is used to calculate the required rate increase or decrease. These are the same amounts shown in the first column of the first 1 of the Fourth Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(KJB-5), "Exhibit A-1 Power Cost Baseline Rate."

III. ADJUSTMENTS TO TEST YEAR POWER COSTS

Q. Please describe each of the adjustments presented in Exhibit No. ___(KJB-4).

A. The adjustments are:

1. **<u>Power Cost</u> – Page one of Adjustment-1,** lines two through eight represent the rate year pro forma power costs presented in Second Exhibit to the Prefiled Direct Testimony of Mr. David E. Mills, Exhibit No. ___(DEM-3). Line nine represents

the production operations and maintenance costs ("production O&M") presented in the Second Exhibit to the Prefiled Direct Testimony of Mr. Ronald J. Roberts, Exhibit No. ___(RJR-3). These costs are the projected rate year fixed and variable production related costs for PSE's rate year power supply portfolio that are adjusted to test year levels using the relationship of normalized test year delivered load to rate year delivered load ("production factor"). These projected costs are a pro forma adjustment to the test year costs shown on the first page of Exhibit No. ___(KJB-4). Line ten presents the transmission expenses that are recovered through the PCA mechanism related to the Third AC, Northern Intertie and Colstrip transmission lines. This category of costs is left at its historical test year level and the adjustment reflects the result of applying the production factor to these test year expenses. The variable transmission income adjustment on line eleven captures revenue earned under PSE's Open Access Transmission Tariff ("OATT"). Under the PCA mechanism, these revenues were typically included in the power cost baseline rate by adjusting revenues to equal the most recent three-year average after being adjusted for non-recurring items. However, in 2013, PSE received FERC approval to utilize a formula rate that adjusts annually for setting PSE's OATT tariff. Consistent with the 2013 PCORC, the variable transmission revenues included in this PCORC are calculated by re-pricing the most recent three-year average of transmission volume across the respective lines at the most current OATT tariff rate. New OATT rates under the formula rate will be finalized by June 1, 2014 and their impact on this adjustment will be included in the supplemental update for this proceeding. Finally, and new to the power cost adjustment, is the calculation of the return on equity of the Coal Transition PPA shown on line twelve.

Q. Please explain the equity return for the Coal Transition PPA.

A. On January 9, 2013 the Commission approved a power purchase agreement between PSE and TransAlta Centralia Generation LLC that provides for PSE's acquisition of an average 346 MW of coal transition power, as defined in RCW 80.80.010, over a contract term of 133 months. The Commission determined that PSE is also authorized by statute to recover an equity return of $1.49 per megawatt hour ("MWh")[15] for all deliveries of power under the Coal Transition PPA. This adjustment increases expenses for electric operations by $2,326,384 to allow for the recovery of the equity adder in the rate year and this item is shown as a separate variable cost line item in the Baseline Rate.

Q. Do you have any further explanations with respect to the power costs in Adjustment -1?

A. Yes. As certain power costs and operation and maintenance ("O&M") costs are also included in other adjustments, it is necessary to reduce the total power cost adjustment by these amounts to avoid a double count in the revenue requirement. Page 5, which is the second page of Adjustment-1, depicts these adjustments and presents a reconciliation of the rate year projections included in the testimonies of Mr. Mills and Mr. Roberts, to the final adjusted rate year power cost and O&M projections included in Adjustment-1. For example, amortizations of regulatory

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[15] Docket UE-121373 Final Order

assets and liabilities that impact power costs are removed from amounts included in Adjustment-1 since they are included in adjustments 10, 13, 14, 15 and 16, which are discussed later in my testimony. Test year benefits and taxes are re-classified out of Mr. Mills' and Mr. Roberts' power costs and production O&M totals and reflected separately on lines 15a and 15d on page 1 of Exhibit No. ___(KJB-4). The remaining rate year power costs have been adjusted to test year power cost levels by the production factor discussed later in my testimony and are the amounts reflected in Adjustment-1.

The total power cost adjustment decreases costs by $994,057.

2. **Montana Energy Tax – Adjustment-2** pro forms the taxes due in the State of Montana that are assessed on Colstrip generation. This adjustment compares the forecast generation of the Colstrip plants that underlies the determination of rate year power costs at the current Montana tax rate to the actual tax expensed in the test year. This adjustment increases expense by $49,314.

3. **Snoqualmie Falls Hydroelectric Redevelopment Project ("Snoqualmie Falls Project") – Adjustment-3** presents the rate base and expenses associated with the Snoqualmie Falls Project. On June 29, 2004, the FERC issued PSE its current license to operate the Snoqualmie Falls Hydroelectric Project, FERC Project No. 2493. This run of the river project consists of a diversion dam and two powerhouses located on the Snoqualmie River in the city of Snoqualmie. As licensed, the installed capacity increased from 44.4 MW to 54.4 MW. Existing recreation facilities consist of viewing decks, picnic areas, trails, restrooms, and an outdoor education center, which are provided as requirements of the license.

The in-service dates for this project were known and were included in PSE's 2013 PCORC. Plant costs and expenses used in calculating this adjustment are discussed in the Prefiled Direct Testimony of Mr. Douglas S. Loreen, Exhibit No. ___(DSL-1T), and supporting exhibits thereto.

This restating adjustment presents the rate base and expenses associated with the diversion dam, plant 2 and plant 1 closing to plant on October 31, 2012, April 17, 2013, and September 5, 2013 respectively. The expected output from the redevelopment project has been included in the AURORA power cost model run for the rate year. The plant balance of $324,638,389, shown on line two of this adjustment, is the restated average of the monthly averages ("AMA") plant cost for the project. This AMA balance is based on the end of period balance of plant in service for the project as of March 31, 2014 of $325,085,015.

Q. Please explain how the rate base was calculated for rate purposes.

A. Per the 2013 PCORC Settlement Stipulation, the Snoqualmie Falls Project plant balances have been restated on an AMA basis to the 13 months ending November 30, 2014 (the beginning of the rate year).[16]

The capital investment based on the March 31, 2014 actual costs of the Snoqualmie Falls Project for each month of the agreed upon AMA restatement period were used to determine the AMA plant balance for the month prior to the beginning of the rate period. To calculate the depreciation expense, the depreciation rate of 3.20 percent approved in the 2013 PCORC was used, which

[16] Docket UE-130617 Settlement Stipulation Page 10, Paragraph 24.

was based on the amount of annual depreciation expense necessary to recover the estimated net book value over the average remaining service life based on the original license expiration date. The accumulated depreciation AMA balance of $7,192,835 is shown on line three of this adjustment. The balance of accumulated depreciation represents the accumulation of the depreciation expense mentioned above as well as an offset for $2,964,662 of cost of removal incurred associated with the project.

As with gross plant and accumulated depreciation, accumulated deferred taxes associated with the tax depreciation of the Snoqualmie Falls Project were calculated using the same AMA restatement period. The deferred tax calculation is based on twenty-year tax depreciation with an additional half-year bonus depreciation included in tax depreciation for the first year it is in service. Additionally, as part of the American Recovery and Reinvestment Act of 2009, PSE has received a U.S. Treasury Grant ("Treasury Grant"), which results in a reduction to the tax basis for the Snoqualmie Falls Project. The half-year convention for tax depreciation, the bonus tax depreciation of 50 percent in the first year, and the reduction to tax basis resulting from the Treasury Grant were applied when determining the deferred tax liability for the restated period. The deferred income tax liability AMA balance of $ 49,134,728 is shown on line four of this adjustment.

The total of all the adjustments described above increases rate base by $121,310,792.

Q. Has PSE included any pro forma rate base for the Snoqualmie Falls Project?

A. No. As stated above, the end of period balance of plant in service totaling $325,085,015 as of March 31, 2014 is used as the basis for this adjustment. Under the 2013 PCORC Settlement Stipulation, PSE is allowed to include post-test year capital additions up to a cutoff date, which is the date of PSE's supplemental filing in the 2014 PCORC.[17] Should additional material post-test year additions after March 31, 2014 become known and measurable in time for the agreed upon cutoff date, they will be included in this adjustment in PSE's supplemental filing.

Q. Please describe the expense adjustment.

A. The calculation of total restated book depreciation expense of $10,362,286 shown on lines eleven and twelve is explained above. The depreciation shown on line twelve is associated with the Treasury Grant tax basis reduction and is not tax deductible. The revenue adjustment restatement for flow through taxes of $833,951 is shown on line thirteen and represents the gross-up associated with the non-taxable depreciation on line twelve. The rate year power generation and production O&M costs associated with the Snoqualmie Falls Project are included in Power Costs **Adjustment-1** and are supported by the Prefiled Direct Testimony of Mr. David E. Mills, Exhibit No. ___(DEM-1CT), the Prefiled Direct Testimony of Mr. Paul K. Wetherbee, Exhibit No. ___(PKW-1T), and the Prefiled Direct Testimony of Mr. Ronald J. Roberts, Exhibit No. ___(RJR-1CT). Property

[17] Docket UE-130617 Settlement Stipulation Page 10, Paragraph 24.

insurance for the project is included in **Adjustment-9.** The Snoqualmie facility is connected directly to PSE's transmission system and as a result, there is no incremental transmission costs associated with the project additions. This adjustment increases expense by $5,624,322.

4. **<u>Upgrades To the Baker River Hydroelectric Project Related to FERC Relicensing ("Lower Baker Upgrade")</u> – Adjustment-4** presents the rate base and expenses associated with the Lower Baker Upgrade. The project includes the Lower Baker Floating Surface Collector ("FSC"), which went into commercial operation on February 14, 2013, and the Lower Baker Powerhouse, which went into commercial operation on July 25, 2013. The FSC involved the construction and installation of a floating steel barge that collects juvenile fish for downstream transport as part of PSE's fish-recovery effort and as required by the Baker River Hydroelectric Project FERC license. The new Lower Baker Powerhouse is a concrete structure containing a 30 MW turbine-generator unit and associated equipment. The structure is located downstream of Lower Baker dam adjacent to an existing powerhouse. The new unit operates in conjunction with the existing powerhouse to generate electricity while maintaining minimum flows in the Baker River for the benefit of migrating fish as stipulated in the FERC license agreement. The AMA plant balance of $160,836,550 shown on line two of this adjustment represents the adjusted plant cost for the project for the restatement period.

Q. Please explain how the rate base addition was calculated for rate purposes.

A. As with Snoqualmie, per the 2013 PCORC Settlement Stipulation, investment for the Lower Baker FSC and the Lower Baker Powerhouse was derived by calculating the 13-month AMA plant balance comprised of actual investment available through March 31, 2014 and sustained through the remainder of the restatement period, which per the 2013 PCORC Settlement Stipulation, was determined to be November 30, 2014, the day prior to the beginning of the rate year. Plant costs and expenses used in calculating this adjustment are discussed in the Prefiled Direct Testimony of Mr. Douglas S. Loreen, Exhibit No. ___(DSL-1T), and supporting exhibits thereto. As noted above, per the 2013 PCORC Settlement Stipulation, PSE may also include post-test year capital additions related to the Baker Projects up to the date of PSE's supplemental filing for this proceeding. To calculate the depreciation expense, actual depreciation was included through March 31, 2014, and the depreciation rate of 2.19 percent which was approved in the 2013 PCORC, was used to calculate depreciation expense for the months after March 31, 2014. The approved depreciation rate represents the average deprecation rate of both projects based on their individual in-service dates and the remaining period left on the FERC license. PSE received the fifty-year license from FERC in October 2008. The depreciation expense was accrued monthly in this calculation, and the resulting monthly accumulated depreciation was averaged in the same manner as the plant cost.

As with gross plant and accumulated depreciation, accumulated deferred taxes associated with the tax depreciation of the Lower Baker Upgrade were calculated using the same AMA restatement period. The deferred tax calculation is based on twenty-year tax depreciation with the additional half-year bonus depreciation included in tax depreciation for the first year it is in service. Additionally, the Lower Baker Powerhouse qualified for a Section 1603 Treasury Grant as will be discussed next, which results in a reduction to the tax basis for one half of the grant amount received. After applying the half-year convention for tax depreciation, recognizing the 50 percent bonus tax depreciation in the first year and including the reduction to tax basis resulting from the Treasury Grant, the AMA deferred tax liability for the Lower Baker Upgrade is $25,432,044 for the rate year, shown on line four of this adjustment.

The total of all the Lower Baker Upgrade adjustments described above increases rate base by $43,967,725.

Q. Please describe the expense adjustment.

A. The calculation of total book depreciation expense of $3,572,389, representing the sum of lines eleven and twelve, is explained above. The depreciation shown on line twelve is associated with the Treasury Grant tax basis reduction and is not tax deductible. Accordingly, line thirteen represents the gross-up associated with this non-taxable portion of depreciation. The rate year power generation and production O&M costs associated with the Lower Baker Upgrade are supported by the Prefiled Direct Testimony of Mr. David E. Mills, Exhibit No. ___(DEM-1CT), the Prefiled Direct Testimony of Mr. Paul K. Wetherbee, Exhibit No. ___(PKW-1T), and the Prefiled Direct Testimony of Mr. Ronald J. Roberts, Exhibit No. ___(RJR-1CT). Property insurance for the project is included in

Adjustment-9. As in the case of Snoqualmie Falls Project, the Baker project is connected directly to PSE's transmission system and as a result, there is no incremental transmission costs associated with the project additions. The Lower Baker Upgrade expense adjustment increases expense by $1,806,578.

5. **<u>Treasury Grants</u> – Adjustment-5.** The Treasury Grant is a subsidy provided by U.S. government per Section 1603 of the American Recovery and Reinvestment Act of 2009 for certain renewable energy projects. For hydroelectric projects providing incremental generation due to improvements as defined by the Internal Revenue Service Code Section 45, the Treasury Grant is an alternative to Production Tax Credits, which some companies, including PSE, have not been able to use in a timely fashion. The Treasury Grant is equal to 30 percent of the qualifying investment, less a 7.2 percent sequestration reduction. The Treasury Grant reduces the tax basis for accelerated tax depreciation by one half of the grant received.

On April 24, 2014, PSE received a payment in the amount of $80,241,567 from the United States Department of the Treasury representing the Treasury Grant related to the Snoqualmie Redevelopment Project.

On May 14, 2014, PSE received a payment in the amount of $27,634,237 from the Treasury Department representing the Treasury Grant related to the Lower Baker powerhouse.

In accordance with the 2013 PCORC Settlement Stipulation, PSE will not apply the conventional method of passing the grants for the Snoqualmie Falls Project and the Lower Baker powerhouse on to customers by way of the Schedule 95A tracker. Rather, per the 2013 PCORC Settlement Stipulation, PSE will apply a regulatory treatment equivalent to a direct rate base reduction by establishing two regulatory liabilities for the amount of the grants received. These Treasury Grants will be treated as a reduction to fixed production rate base (included in a PCORC and the PCA) and, beginning on the receipt dates of the Treasury Grants, will be amortized over the remaining lives of the associated hydroelectric facilities which are equivalent to their FERC license periods.

The Snoqualmie Treasury Grant balance of $80,241,567 on line three represents the 13-month AMA of the grant receipt amount, through the end of the rate year. The amortization expense was calculated by dividing the Treasury Grant balance by the 30 years remaining on the 40-year Snoqualmie FERC license. The accumulated amortization was derived by calculating the AMA of the accumulated amortization through the end of the rate year and is shown on line four in the amount of $2,933,324. The total adjustment to the test year for the rate base offset related to the Snoqualmie Treasury Grant is $77,308,243.

The Baker Treasury Grant balance of $27,634,237 on line eight represents the 13-month AMA of the grant receipt amount, through the end of the rate year. The amortization expense was calculated by dividing the Treasury Grant balance by the 44 years remaining on the 50-year Baker FERC license. The accumulated amortization was derived by calculating the AMA of the accumulated amortization through the end of the rate year and is shown on line nine in the amount of $649,825. The total Treasury Grant adjustment decreases rate base by $104,292,654 and is shown on line twelve. As explained previously, the amortization expense for the Treasury Grants is calculated using the remaining life of the underlying asset, which is tied to the license term, and the amortization reflected on line seventeen of $2,659,941 and line twenty one of $619,833 represent the rate year amortization for the Snoqualmie and Baker Treasury Grants respectively. This adjustment decreases expense by $3,279,775.

6. **<u>Treasury Grants Deferral</u> – Adjustment-6** includes the rate year amortization expense and net rate base amount for deferred costs associated with the Treasury Grants for the Snoqualmie Project and Baker Project. In accordance with the 2013 PCORC Settlement Stipulation, PSE will defer the return of and the return on the Treasury Grants in the same manner as permitted under RCW 80.80.060 deferrals for resources such the Lower Snake River wind plant ("LSR") and Mint Farm Energy Center that have been approved in prior rate proceedings. Per the 2013 PCORC Settlement Stipulation, the recognition and deferral of the return of and return on the Treasury Grant balances commences when PSE receives the Treasury Grants and will cease to accumulate once the balances of the Treasury Grants are included in rates in the 2014 PCORC. The amortization of the deferrals will be set in the 2014 PCORC to fully amortize by October 31, 2018 as called for in the 2013 Settlement Stipulation.[18] When compiling this filing, it was discovered that the ending amortization date referenced in the 2013 Settlement Stipulation and the Final Order was incorrect. The ending amortization date in the 2013 PCORC was intended to be the same as the plant deferrals for the Snoqualmie Falls Project and Lower Baker Upgrade that were deferred under

[18] Paragraph 23 of Final Order 6 in Docket No. UE-130617.

RCW 80.80.060 and were approved for recovery in the 2013 PCORC. The ending amortization date for these plant deferrals was in fact six years from the November 2013 rates effective date, or October 31, 2019. In order to be compliant with the 2013 PCORC Settlement Stipulation and Final Order as written, PSE has kept the Treasury Grant amortization ending date as October 31, 2018. And, to conform to the intent of having the plant and Treasury Grant deferrals for the projects end on the same date, PSE has adjusted the plant deferral amortization end dates to match the October 31, 2018 date. These plant deferrals are included in **Adjustment-12**. The Treasury Grant deferrals and their associated amortization will be treated as variable costs in the PCA mechanism and included in Exhibit D which is consistent with the treatment afforded the other RCW 80.80.060 plant deferrals that have been previously approved by the Commission.

The deferral period is the grant receipt date through November 30, 2014. The deferral represents the sum of the return on the Treasury Grant balance net of accumulated amortization as well as the amortization expense for the deferral period. The return on rate base is calculated using PSE's authorized net of tax rate of return grossed up for income taxes. PSE began deferring the return and the amortization expense for the Snoqualmie Treasury Grant on April 24, 2014, the receipt date of the cash payment, and began deferring the return and the amortization expense for the Baker Treasury Grant on May 14, 2014, the receipt date of the cash payment.

The resulting deferral balances of $3,682,635 for Snoqualmie shown on line eighteen and $1,066,057 for Baker shown on line twenty-three are net of accumulated deferred income taxes and represent the AMA balances at the end of the rate year.

The resulting amortization of $1,658,222 for Snoqualmie shown on line three and $480,026 for Baker shown on line seven of the adjustment, represents the impact of this calculation on expense.

As a result of this adjustment, rate base is decreased by $4,748,692, which is shown on line twenty-five and the amortization expense is decreased by $2,138,248, which is shown on line eleven of the adjustment.

7. **Sale of Electron – Adjustment-7** is intentionally left blank and included here only as a placeholder pending developments on the expected sale of the Electron facility.

8. **Remove Wild Horse Solar- Adjustment-8** restates the test year and removes the effects of the solar project at Wild Horse. This power project is a demonstration project, and PSE is not requesting recovery of the costs associated with it at this time. This adjustment decreases expense for electric operations by $ 187,935 and decreases rate base by $2,439,424.

9. **Property Insurance – Adjustment-9** reflects the actual premium increases for production property insurance expense and increases expense for electric operations by $171,261.

10. **Bonneville Exchange Power – Adjustment-10** trues up the production related regulatory asset, net of deferred federal income taxes, to its projected rate year AMA balance. The amount of the decrease to rate base of $4,582,987 was determined using the amortization schedule approved in prior rate cases. No adjustment to expense is necessary as the test year level represents the amortization expense that will exist in the rate year.

11. **Regulatory Assets –White River Hydroelectric Project- Adjustment-11** trues up the production related regulatory assets and liabilities, net of deferred federal income taxes, to their projected rate year AMA balances. The amount of the decrease to rate base of $1,848,458 was determined using the amortization schedules approved in prior rate cases. No adjustment to expense is necessary as the test year level represents the amortization expense that will exist in the rate year.

12. **Plant Deferrals - Adjustment-12** pro forms rate base and amortization related to the plant deferrals associated with resources approved in prior proceedings to rate year levels.

Plant Deferral Rate Base: The amount of the decrease to rate base for resources approved in prior rate cases, such as the Mint Farm Energy Center in Docket UE-090704 and LSR Phase 1 in Docket UE-111048, was determined using the amortization schedules approved in prior rate cases. AMA deferral balances for resources such as Ferndale, the Snoqualmie Falls Project and the Lower Baker Upgrade, which were recently approved in the 2013 PCORC, reflect an increase in lines four through six primarily because the test year did not include a full 12 months of the deferral balances for these resources. Additionally, the difference between actual deferred costs and those estimated during the 2013 PCORC proceeding has been included for these three projects and also impacts the resulting rate year deferral balance.

Plant Deferral Amortization: No adjustment to expense is necessary for the Mint Farm plant deferral as the test year level represents the amortization expense that will exist in the rate year. Expense for the LSR plant deferral on line eleven reflects the slight reduction in test period amortization expense to reflect annual amortization approved in the 2013 PCORC. The increased amortization for Ferndale, the Snoqualmie Falls Project and the Lower Baker Upgrade on lines twelve through fourteen represents the difference between a full rate year of amortization based on updated actual deferred costs discussed above and the partial test year amortization. The amortization period for the Ferndale deferral was left at October 31, 2019, and the amortization expense was reset to fully amortize the actual deferred balance at the beginning of the rate year by that date. Additionally, as discussed earlier, the amortization periods for the Snoqualmie Falls Project and Lower Baker Upgrade deferrals have been changed from October 31, 2019, to October 31, 2018, to reflect the end dates for the amortization periods as agreed upon by parties in the 2013 PCORC Settlement Stipulation.

This adjustment brings rate base and expense to rate year levels based on actual deferrals. This adjustment decreases rate base by $3,176,758 and increases expense by $6,652,847.

13. **Capacity Payments on Westcoast Pipeline (FB Energy and BNP Paribas) - Adjustment-13** trues up rate base related to capacity payments made to PSE by FB Energy and BNP Paribas approved in Dockets UE-090704 and UE-100503. The amount of the increase to rate base of $1,158,371 was determined using the amortization schedules approved in prior rate cases. No adjustment to expense is necessary as the test year level represents the amortization expense that will exist in the rate year.

14. **Chelan PUD Contract Initiation Payments & Security Deposit – Adjustment-14** trues up rate base and amortization related to a security deposit and initiation payment made under the Chelan Public Utility District ("Chelan PUD") power sales agreement for the output of the Rock Island and Rocky Reach hydroelectric projects to rate year levels. The rate base and amortization expense for this rate year adjustment is calculated by using the amortization schedules approved in prior rate cases. This adjustment decreases rate base by $11,815,758. No adjustment to expense is necessary as the test year level represents the amortization expense that will exist in the rate year.

15. **Other Miscellaneous Regulatory Assets - Adjustment-15** trues up rate base and amortization related to the Colstrip Units 1 and 2 reservation dedication payment and FERC Part 12 study non construction costs, that were both approved for recovery in prior rate proceedings. This adjustment decreases rate base by $1,420,764. No adjustment to expense is necessary as the test year level represents the amortization expense that will exist in the rate year.

16. <u>LSR Prepaid Transmission and Deferred Carrying Charges</u> - Adjustment-16 trues up rate base and amortization related to the LSR prepaid transmission deposit with BPA as well as the deferred carrying charges on the deposit that were both approved for recovery in prior rate proceedings. The rate base and amortization expense for this regulatory asset have been changed to reflect the regulatory treatment for a transfer of BPA large generator interconnection agreement ("LGIA") credits ("transferred transmission credits") to Portland General Electric ("PGE") upon PSE's sale and transfer of certain assets relating to LSR Phase II to PGE. PSE assigned certain BPA transferred transmission credits in an amount equal to $20,500,000 to PGE as authorized by the Commission on July 31, 2013 in Docket UE-131230. PSE had originally made prepayments of $102.2 million to BPA to construct the Central Ferry Substation and certain transmission network upgrades to interconnect the output of the various phases of the Lower Snake River Wind Project, including LSR Phase 1 and LSR Phase 2. PSE's total prepayment of $102.2 million to BPA consisted of a $2.5 million prepayment for interconnection facilities and a $99.7 million prepayment for network upgrades. BPA will continue to refund to PSE the prepayment related to the network upgrade facilities, plus interest, through transmission credits to PSE's point-to-point transmission tariff expenses in the future, but BPA's refund obligation will be reduced by the $20,500,000 of transmission credits transferred to PGE.

The format of the amortization schedule used to determine the rate year balance of this regulatory asset was the same as was used in prior rate proceedings. The amortization schedule includes recognition of the payment of $20,500,000 for assignment of the prepayment to PGE as of the actual release date of October 15, 2013. Additionally, the amortization schedule includes the transmission credits that are estimated to be received by PSE from BPA throughout the rate year. This adjustment decreases rate base by $23,187,029 and the amortization expense on this regulatory asset occurring in the rate year increases expense by $2,033,759.

The $17.4 million original carrying charges on the original transmission deposit are also included in rate base on line three, as approved in prior rate proceedings. The rate base and amortization expense for this adjustment were calculated using the amortization schedule approved in prior rate proceedings. This amortization schedule was reduced by $96,421 for interest at PSE's after tax rate of return grossed up for federal income taxes that was accrued on the payment of $20,500,000 for assignment of the prepayment to PGE from the date of receipt, October 15, 2013, through October 31, 2013 . This adjustment reduces rate base by $912,905 shown on line three and reduces expense by $6,832 shown on line eight.

17. **Hedging Line of Credit – Adjustment-17** pro forms in the commitment costs associated with PSE's line of credit for hedging. In Docket UE-060266 and UG-060267, the Commission approved recovery of costs associated with a line of credit supporting hedging transactions in the PCA and Purchased Gas Adjustment mechanisms. Interest expense and debt issuance amortization are allocated to the gas or electric book based on actual historical activity of access to the credit facility by each energy portfolio. For this adjustment, 59 percent is allocated to electric book. PSE recently brokered an amendment to the hedging line of credit to extend the maturity date by one year and update other terms and conditions. The annualized costs of this amendment were included with the facility fees in this transaction. This adjustment reflects the difference between the facility costs that existed in the test year and the lower annualized cost of the new facility and decreases expense by $325,540.

18. **<u>Production Adjustment</u> – Adjustment-18** pro forms the production related rate base and expenses that have not been included in **<u>Power Cost</u> – Adjustment-1**. As with **<u>Power Cost</u> – Adjustment-1**, these costs are adjusted to test year levels using the production factor, the ratio of test year delivered load to rate year delivered load, so that the test year level of costs are collected in the rate year. The test year delivered load of 21,215,954 MWhs has been adjusted by the temperature normalization, a reduction of 19,657 MWhs, which is discussed in more detail in **Adjustment–19 Temperature Normalization** below. Additionally, 100,949 MWhs of Jefferson County load for January through March of the test year were subtracted as Jefferson County PUD began electric service for its customers on April 1, 2013. The resulting adjusted test year delivered load of 21,095,347 MWhs divided by the rate year delivered load of 21,304,356 MWhs results in a production factor of 0.981 percent. When applied to the production costs and rate base in this adjustment, it reduces rate base by $24,001,888 and expense by $1,598,695.

19. **<u>Temperature Normalization</u> – Adjustment-19,** shown on page 24 of Exhibit No. ___(KJB-4), presents the adjustment to test year load to a level which would have been expected to occur had the temperatures during the test year been "normal". The "normal" temperature is assumed to be the average value taken for a thirty-year period ending December 2013. The difference between the actual test year Generated, Purchased and Interchange ("GPI") load and the temperature normalized GPI is adjusted for system losses. The test year was cooler than normal requiring an adjustment to load that decreases actual GPI by 21,135 MWh, or 19,657 MWh when adjusted for line losses.

20. **<u>Conversion Factor</u> – Adjustment-20** shown on page 25 of Exhibit No. ___(KJB-4) allows the deficiency or surplus to be grossed up for revenue sensitive items to determine the total revenue deficiency or surplus. The calculation of this conversion factor uses the bad debt percentage from the electric Expedited Rate Filing in Docket UE-130137, current annual Washington State utility tax and the Washington Utilities and Transportation Commission annual filing fee rates. The conversion factor used in this proceeding is .954379.

IV. PROPOSAL TO RECOVER INCREMENTAL COSTS FOR THE COAL TRANSITION PPA DUE TO CONTRACTED VOLUME AND PRICE INCREASES

Q. Please explain how PSE proposes to address the contracted volume and price increases for the Coal Transition PPA.

A. PSE proposes that the contracted volume and price increases associated with the Coal Transition PPA be accomplished through either 1) a PCORC filing; (2) a compliance filing made 60 days before December 1, 2015 and December 1, 2016; or 3) a combination of PCORC and compliance filing if a PCORC addresses only a partial year of a contract change thus requiring a compliance filing to address the remainder of the contract year.

Q. What is the basis for PSE's proposed approach?

A. The proposed approach is consistent with the approach proposed by PSE and WUTC Staff in the Multiparty Settlement Agreement in Docket UE-121373. Although the Commission rejected the Multiparty Settlement, it encouraged PSE to propose an alternative to allow for recovery of incremental increases in the Coal Transition PPA through a compliance filing. Specifically, in Order 8 in Docket UE-121373, the Commission encouraged PSE to:

> propose in the context of its initial PCORC filing additional clarifications, such as the compliance filing approach suggested by Multiparty Settlement Agreement, and how this will interact with annual adjustments in the PCA baseline.[19]

Q. Please explain the proposed compliance approach.

A. PSE proposes that for each of the December 2015 and December 2016 increases, PSE would submit a compliance filing to update Schedule 95 and the PCA Baseline Rate for the price and volumes of the contract and the equity adder. The updated costs of the Coal Transition PPA would be offset by the cost of the market power currently being recovered in rates that the additional PPA replaces.

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[19] Order 08 at ¶ 53.

Q. Please explain how the incremental costs associated with the Coal Transition PPA will be calculated.

A. The rate year power costs in this PCORC, as discussed in the Prefiled Direct Testimony of Mr. David E. Mills, Exhibit No. ___(DEM-1CT), reflect the initial 180 megawatts (MW) of Coal Transition PPA volumes effective for the rate year beginning December 1, 2014. Subsequent to the rate year, on December 1, 2015, the volume increases to 280 MW and on December 1, 2016, the volume increases again to 380 MW.

To calculate the incremental costs associated with the December 1, 2015 change, PSE would update the FERC Account 555, purchased power costs, on Exhibit A-1 to reflect the December 1, 2015 through November 30, 2016 contract costs of the Coal Transition PPA. Additionally, PSE would reduce the FERC Account 555, for the cost of secondary purchases built into rates for the incremental volumes. Finally, line 10a on Exhibit A-1, the Coal Transition PPA equity component, would be increased by the equity return on the increased volumes. Exhibit No. ___(KJB-7) depicts an example of how the incremental costs for the Coal Transition PPA would be calculated.

Q. What will be the timing of the annual compliance filing?

A. PSE will file no later than October 1, 2015, an update to the Exhibit A-1 from the 2014 PCORC compliance filing, providing Staff and the parties 60 days to review the filing. PSE will make a similar filing no later than October 1, 2016 to reflect the increases to the Coal Transition PPA effective December 1, 2016. Rates will be adjusted on December 1 of 2015 and 2016 to reflect the incremental costs associated with the Coal Transition PPA.

V. POWER COST BASELINE RATE

Q. Please describe the impact of the pro forma adjustments on the Baseline Rate.

A. Exhibit No. ___(KJB-5) shows the impact of the above adjustments on the Power Cost Baseline Rate. The costs are allocated between fixed and variable, and the total costs are adjusted for revenue sensitive items. The total costs of $1,271,288,818 are divided by the test year delivered load of 21,095,348 MWhs to calculate the new Baseline Rate of $60.264 per MWh before revenue sensitive items and $63.145 per MWh after revenue sensitive items.

Q. Please explain the remaining pages included in Exhibit No. ___(KJB-5).

A. The remaining pages of Exhibit No. ___(KJB-5) are equivalent to the Exhibits A-2 through D included in the 2001 GRC Settlement Stipulation and have been updated to reflect the changes in power costs presented by PSE.

Q. How will the new Baseline Rate be implemented?

A. Each month PSE calculates the potential over or under collection of power costs for the PCA. For the fixed cost component of the PCA, these costs are attributed equally over the twelve month period. Once the new rate is effective, this part of the calculation will be changed to reflect the new monthly fixed costs allowed in the PCA for the remaining days and months of the PCA period.

Because the variable costs are adjusted to actual variable costs, there will be no change to the way this cost category is determined in the PCA calculation. Any necessary further adjustments required under the PCA mechanism will then be deducted from these costs.

The total of the above adjustments for an individual month will then be compared to the kilowatt hours for such month multiplied by the appropriate Power Cost Baseline Rate, and the algebraic sum of these variances for the PCA period will be the amount that will be considered in the sharing mechanism of the PCA.

In other words, the algebraic total of each month's variance for the PCA period will determine if there is any refund or collection of power costs required for the PCA period, after consideration of the various PCA bands.

VI. RATE CHANGE

Q. Please explain how PSE calculated the rate change required after taking into consideration the pro forma and restating adjustments.

A. As PSE is only requesting that the portion of its rates related to the PCA mechanism be adjusted using the power cost only rate filing, the required change in rates has been calculated using the difference between the 2013 PCORC Baseline Rate currently being used and the proposed Baseline Rate (each grossed up for revenue sensitive items). This calculation is shown in Exhibit No. ___(KJB-6) and, as shown on line 16, the new rate is $63.145 per MWh and the current rate is $63.598. The difference between these two rates is multiplied by the normalized delivered load for the test period from the current filing. The result of this calculation is the requested change in revenue after revenue sensitive items. This change in rates results in an average decrease of approximately 0.456 percent. The net $9,556,193 surplus included in this Baseline Rate is comprised of a $21.3 million surplus representing lower fixed costs resulting primarily from the receipt of the Treasury Grants, offset by a $11.7 deficiency representing higher variable costs associated with power costs, primarily related to the addition of the Coal Transition PPA. *See* the Seventh Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(KJB-8), lines 51 and 53.

Q. Is PSE proposing to file for recovery or return of any power cost deferrals under Section 4 of the 2001 GRC Settlement Stipulation in this PCORC?

A. No.

VII. CONCLUSION

Q. Does this conclude your prefiled direct testimony?

A. Yes, it does.