Exhibit No. ___ (CTM-1T)
Docket UE-130617
Witness: Christopher T. Mickelson

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of **PUGET SOUND ENERGY, INC.** **For an Accounting Order Authorizing Accounting Treatment Related to Payments for Major Maintenance Activities**	**DOCKET UE-130583**
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.** **Respondent.**	**DOCKET UE-130617**
In the Matter of the Petition of **PUGET SOUND ENERGY, INC.** **For an Accounting Order Authorizing Accounting the Sale of the Water Rights and Associated Assets of the Electron Hydroelectric Project in Accordance with WAC 480-143 and RCW 80.12**	**DOCKET UE-131099**

In the Matter of the Application of **PUGET SOUND ENERGY, INC.,** **For an Order Authorizing the Sale of Interests in the Development Assets Required for the Construction and Operation of Phase II of the Lower Snake River Wind Facility**	**DOCKET UE-131230**

TESTIMONY OF

CHRISTOPHER T. MICKELSON

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Company Accounting Petition for Major Maintenance Activities in Docket UE-130583; Treasury Grants, Ratemaking Treatment; Adjustments for Power Cost Rate; Revenue Requirement; Revenue Allocation and Rate Design

August 14, 2013

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LIST OF EXHIBITS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher Thomas Mickelson. My business address is the Richard Hemstad Building, 1300 S. Evergreen Park Drive S.W., Olympia, Washington 98504.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission (Commission) as a Senior Regulatory Analyst in the Energy Section of the Regulatory Services Division. Among other duties, I am responsible for analyzing financial, accounting, and revenue allocation and rate design issues in general rate cases, accounting petitions, and other tariff filings, as they pertain to the electric and natural gas companies under the jurisdiction of this Commission.

Q. How long have you been employed by the Commission?

A. I have been employed by the Commission since June 2007.

Q. Would you please state your educational and professional background?

A. I graduated from the University of Washington (UW) in 2002, receiving a Bachelor of Arts degree in Business Administration. While attending UW, I performed the duties of accounts payable and subcontracting accounting for Sellen Construction Company. In 2006, I was employed as a fraud auditor for Washington State

Department of Labor & Industries. Since joining the Commission, I have attended several regulatory courses, including the 49th Annual National Association of Regulatory Utility Commissioners Regulatory Studies Program held at Michigan State University in East Lansing, Michigan.

I filed testimony on uncollectible expenses, net-to-gross conversion factor, electric cost of services, revenue allocation, rate design, and service charges in Pacific Power & Light Company, d/b/a PacifiCorp's (PacifiCorp) general rate case (GRC), Docket UE-130043. Furthermore, I filed testimony on Aldyl-A pipe replacement accounting treatment, electric and natural gas cost of services, revenue allocations and rate designs in Avista Corporation's (Avista) GRC, Dockets UE-120436 and UG-120437. In addition, I filed testimony on natural gas revenue requirement, revenue allocation and rate design in Puget Sound Energy, Inc.'s (PSE or the Company) GRC, Docket UE-111048 and UG-111049. I was the lead analyst in numerous other tariff applications, including GRCs of Murrey's Disposal Company, Inc., Docket TG-090097; American Disposal Company, Inc., Docket TG-090098; Washington Water Service Company, Docket UW-090733; and Waste Management of Washington, Inc., Dockets TG-091933 and TG-101080.

I have participated in the development of Commission rules, prepared detailed statistical studies for use by commissioners and other Commission employees, and examined utility and transportation company reports for compliance with Commission regulations. I have also presented Staff recommendations at numerous open public meetings.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present Staff's overall recommendations in this case, based on my analysis and the analyses of other Staff assigned to this case. I calculate the Power Cost Rate and I am responsible for revenue allocation and rate design. I make recommendations regarding the following: (1) appropriate handling of assets and expenses for the rate year compared to the test year or last GRC; (2) treatment of planned major maintenance pertaining to the accounting petition in Docket UE-130583; (3) treatment of hydro production operations and maintenance (O&M); and (4) proper treatment of the United States Department of the Treasury (Treasury) Grants for Snoqualmie Falls Hydroelectric Redevelopment Project (Snoqualmie Project)[1] and Lower Baker River Hydroelectric Project (Baker Project).[2]

I also introduce the remaining witnesses that provide testimony in this proceeding on behalf of Commission Staff and briefly summarize Staff's position in each of the dockets.

Q. Please introduce the other Staff witnesses testifying in this proceeding and the subjects of their testimony.

A. The following witnesses present testimony and exhibits for Staff:

- Mr. Edward J. Keating recommends a reduction in power supply expense of approximately $1.984 million based on the removal of costs associated with the

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[1] Barnard, Exhibit No. KJB-01CT at pages 10-11.
[2] *Id.*, at pages 17-18.

purchase of biogas from the Cedar Hills Regional Landfill Facility (Cedar Hills). He responds to Company witness David E. Mills.

- Ms. Juliana M. Williams addresses the appropriate ratemaking treatment of pro forma rate base additions and prudence determination regarding PSE's acquisition of the Ferndale Generating Station (Ferndale Plant); upgrades to the Snoqualmie Project; and the addition of a generator and other equipment for the Baker Project.[3] She responds to Company's witnesses David E. Mills, Roger Garratt, Michael Mullally, Aliza Seelig, Roger Garratt, Paul K. Wetherbee, Douglas S. Loreen, and Katherine J. Barnard.
- Mr. David C. Gomez presents recommendations on the treatment of net power costs including adjustments related to purchase power that removes the costs associated with the Electron PPA and replaces it with AURORA modeled Mid-C Flat prices. He also recommends that the Commission approve the sale and transfer of the Electron project to Electron Hydro LLC,[4] with conditions. He does not support the Company's proposed ratemaking and accounting treatment as the sale has not closed and a decision on such treatment is premature. Instead, he recommends that the Electron plant stay in rate base until the sale is formalized. His testimony responds to Company witnesses Tom A. DeBoer, David E. Mills, Paul K. Wetherbee, and Matthew D. Rarity.
- Ms. Joanna Huang presents testimony and a recommendation in response to the Company's petition asking for an order authorizing the transfer of the purchased

[3] *Id.*, at pages 17-18.
[4] *Puget Sound Energy, Inc.*, Docket UE-131099, Order Authorizing the Sale of Water Rights and Associated Assets of the Electron Hydroelectric Project in Accordance with WAC 480-143 and RCW 80.12 (June 6, 2013).

assets and its accounting treatment for the balance of the regulatory asset associated with the BPA substation loan that was assigned to Phase 2 of the Lower Snake River Wind Project (LSR Phase 2).[5]

Q. Please briefly describe the Power Cost Rate and its role in setting rates.

A. The Power Cost Rate is a product of PSE's 2001 GRC, in which the Commission approved the parties' *Settlement Stipulation for Electric and Common Issues* (Settlement Stipulation).[6] In that case, the Commission authorized the use of a Power Cost Adjustment Mechanism (PCA) as a method for adjusting PSE's power costs. The Power Cost Rate is the baseline rate used to determine the deferrals under the PCA.

Q. Please briefly summarize Staff's position in Docket UE-130617, PSE's Power Cost Only Rate Case (PCORC).

A. Staff's position, reflects the known and available information, results in a decrease in revenue requirement by $15,775,123, resulting in a decrease in the Power Cost Rate from $64.099 to $63.345 per MWh. This change in rates results in an average decrease of approximately 0.77%.

Q. Please briefly summarize Staff's position in Docket UE-130583, PSE's petition for an accounting order regarding major maintenance.

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[5] *Puget Sound Energy, Inc.*, Docket UE-131230, Order Authorizing the Sale of Interests in the Development Assets Required for the Construction and Operation of Phase II of the Lower Snake River Wind Facility (June 27, 2013).

[6] *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-011570 and UG-011571, Twelfth Supplemental Order (June 20, 2002).

A. Staff's position is that the Commission should deny the Company's petition and require PSE to follow an acceptable method of accounting under GAAP, such as amortize the costs of a major maintenance event over the three years following the time of that event. I testify to Staff's position on this issue in Section III.B.

Q. Please briefly summarize Staff's position in Docket UE-131099, PSE's petition regarding the sale of the Electron Project.

A. Staff's position is that the Commission should approve the transfer of property as in the public interest, but only if the sale is consummated according to the terms of the Asset Purchase Agreement as filed by the Company in its application. Mr. Gomez testifies to Staff's position on this issue and explains how the sale is in the public interest.

Q. Please briefly summarize Staff's position in Docket UE-131230, regarding the accounting and ratemaking treatment of PSE's sale of Bonneville Power Administration (BPA) Transmission Service Credits to Portland General Electric (PGE).

A. Staff's position is that the Commission should reduce the principal balance of PSE's $99.8 million regulatory asset associated with a prepayment to BPA by $20.5 million, and reduce the balance of PSE's regulatory asset associated with accrued carrying charges on that $99.8 million prepayment by approximately $3.566 million. Ms. Huang testifies to Staff's position on this issue and explains these reductions.

Q. Please explain how the rest of your testimony is organized.

A. In Section III of my testimony, I discuss issues that affect the various ratemaking adjustments presented in Section IV. Those issues include: (1) appropriate handling of assets and expenses for the rate year compared to the test year or last GRC; (2) treatment of planned major maintenance; (3) treatment of hydro production O&M; and (4) proper treatment of the Treasury Grants for Snoqualmie Project and Baker Project.

In Section IV, I present the uncontested and contested ratemaking adjustments recommended by Staff to develop the Power Cost Rate.

In Section V, I describe the impact of the adjustments in Sections III and IV on the Power Cost Rate. I also allocate the costs between fixed and variable, and the total costs are adjusted for revenue sensitive items.

In Section VI, I provide Staff's recommendation for both revenue allocation and rate design are consistent with the Settlement Stipulations. The difference between Staff and PSE revenue allocation and rate design is due only to the difference in revenue requirement.

Q. Do you sponsor any exhibits?

A. Yes, I sponsor the following exhibits:

- Exhibit No. CTM-2, Power Cost Rate Adjustments
- Exhibit No. CTM-3, Power Cost Rate
- Exhibit No. CTM-4, Revenue Requirement
- Exhibit No. CTM-5, Electric Revenue Allocation and Rate Design

- Exhibit No. CTM-6, U.S. Department of Treasury's Program Guidance

III. POWER COST ISSUES

Q. What issues do you address in this section of your testimony?

A. I address the following issues: 1) the appropriate rate year; (2) proper treatment of planned major maintenance activities; (3) proper treatment of hydro production O&M; and (4) proper treatment of **the Treasury Grants for the Snoqualmie Project and Baker Project.**

A. Test Year Compared to Rate Year

Q. Please explain "test year" and "rate year" as those terms are used in this case.

A. The test year is a historical twelve-month period; in this case, it is October 1, 2011, through September 30, 2012 (test year). The rate year refers to a future twelve-month period, in which the costs and timing of rate collection are the same time period.

The rate year method has a well-documented history of use with the Commission and is supported in Ms. Barnard's direct testimony, stating "[i]n both a general rate case and a PCORC, the Company uses a future rate year to determine certain power costs and then pro forms those cost back to the test year."[7]

[7] Barnard, Exhibit No. KJB-1CT at page 5, lines 7-9.

Q. What test year and rate year is Staff using in this case?

A. Staff uses a test year of October 1, 2011, through September 30, 2012. Staff uses a rate year of December 1, 2013 through November 30, 2014 (rate year).

Q. What test year and rate year is PSE using in this case?

A. PSE uses the same test year as Staff, but the Company uses a rate year beginning one month earlier: November 1, 2013 through October 31, 2014, with one exception.

Q. What is the one exception in which PSE does not use a rate year beginning November 1, 2013?

A. The exception is PSE's LSR Adjustment (Adjustment 3). In that adjustment, PSE uses what the Company calls an "adjusted test year" [8] period of March 1, 2012, to February 28, 2013.

Q. Has the Commission consistently used the rate year method to calculate costs for the PCA?

A. Yes. The Commission has used the rate year method since the inception of PSE's PCA. Under the terms of the Settlement Stipulation, fixed rate components that are eligible for recovery under the PCA were to be "at the last general rate case or PCA resource case revenue levels."[9]

The "PCA resource case revenue levels" is the same as the rate period; the period in which costs are to be recovered. This is supported by testimony from PSE

[8] Barnard, Exhibit No. KJB-4C at page 7.
[9] Barnard, Exhibit No. KJB-3 at page 4.

witness Mr. John H. Story in an earlier PCORC, when he stated: "[i]n a general rate case, the Company uses a future rate year to determine certain power costs and then pro forms those costs back to the test year."[10] Ms. Bernard's testimony in this case is essentially the same,[11] which highlights the consistency of this practice.

In addition, the Commission has stated it's "goal has been to set the baseline as close as practicable to what is likely to be experienced during the rate year"[12] and repeated a similar statement that "[t]he Commission's goal is to set the Power Cost Baseline Rate as close as possible to what is expected to be experienced in the rate year and expect this to continue going forward."[13]

Q. Why is Staff using a different rate period than PSE?

A. The procedural schedule in this case will implement new rates as of December 1, 2013; therefore, to be consistent with the procedural schedule, Staff reflects the same rate year: December 1, 2013 through November 30, 2014.

Q. Is the Company's use of an "adjusted test year" period of March 1, 2012, to February 28, 2013, for the LSR Adjustment consistent with the rate year method?

A. No. This "adjusted test year" is neither the last GRC period, nor the current PCORC's test year, nor the current PCORC's rate year, nor the PCA resource case

[10] *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket No. UE-060266 – Story, Exhibit No. JHS-1T at page 54, lines 14-16 (February 15, 2006).
[11] *Supra*, see note 23.
[12] *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket Nos. UE-060266 and UG-060267, Order 08 (January 5, 2007) at ¶ 22.
[13] *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket No. UE-072300, Order 13 (January 15, 2009) at ¶ 11.

revenue levels; and therefore, it does not conform to the Settlement Stipulations and past practice in prior PCORCs.

Q. Why is the Company using a different rate period for one asset?

A. Staff assumes the Company chose to depart from past practice due to the effect deferred income tax liability and accumulated depreciation would have on the additional plant balance that the Company brings in by picking its "adjusted test year" period.

Q. How does Staff's use of a different rate year than PSE affect the adjustments Staff is presenting?

A. Staff changing the Company's Adjustment 3, which used an "adjusted test year," to reflect the rate year for calculation of average of monthly averages (AMA) of plant balance, deferred income tax liability, accumulated depreciation, and operating expenses amounts. In addition, Staff "pushes forward" all other adjustments, if the information was available, to reflect the rate year consistent with the procedural schedule in this case, which will implement new rates as of December 1, 2013. Therefore, the rate year difference affects all adjustments that are discussed in my testimony under Section IV, subtopics B and C.

Q. What adjustments are affected by Staff using the rate year December 1, 2013, to November 30, 2014, rather than the Company's rate year?

A. The different rate year affects all adjustments, with the exception of those listed as uncontested adjustments, which I discuss later in my testimony. However, Staff's Adjustment 3 for LSR is also affected for the additional reason that the Company is using an inappropriate "adjusted test year." This changes the AMA amounts for LSR as follows:

- Plant balance from $689,560,142 to $691,417,400.
- Deferred income tax liability from $49,545,868 to $140,245,736.
- Accumulated depreciation from $14,380,018 to $55,936,982.
- Operating expenses from $28,651,131 to $29,062,357.

Q. What is Staff's conclusion on the rate year issue?

A. For the reasons set forth above, the Commission should adopt Staff's rate year and also reject the Company's use of a special "adjusted test period" for a single asset: LSR. Staff's recommendation is consistent with the Settlement Stipulation, the matching principle, and past practice.

B. Major Maintenance Activities (Docket UE-130583)

Q. What are major maintenance activities?

A. Major maintenance activities typically occur when PSE overhauls or substantially upgrades various systems and equipment for purposes of maintenance or modernization, on a scheduled basis. Extensive testing is usually conducted as part of this activity.

For example, replacing old analog electrical equipment with new digital electronic equipment in a power plant most likely would be considered major maintenance. Typically, this sort of major maintenance is planned by utility engineers, who schedule the maintenance well in advance.

Q. How is this issue presented in this case?

A. This issue is presented in the Company's direct case in the PCORC in PSE Adjustment 20.[14] In addition, the Commission consolidated the Company's major maintenance accounting petition (Docket UE-130583)[15] with the PCORC docket. In that petition, PSE asks for authorization of "accounting treatment for payments made under an existing Long Term Service Agreement ("LTSA") with General Electric International, Inc. ("GE") for Mint Farm Combined Cycle Generating Station ("Mint Farm Facility")."[16]

The accounting treatment the Company seeks in its accounting petition is the same as the accounting treatment reflected in Company Adjustment 20.

Q. What is the appropriate accounting for major maintenance costs?

A. The appropriate accounting for major maintenance is to amortize these major maintenance costs following the time of the major maintenance event until the next major maintenance event, without earning a return on the unamortized balance for the expense. This is an acceptable method under generally accepted accounting principles (GAAP).

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[14] Barnard, Exhibit No. KJB-1CT, at 32-35.
[15] *Puget Sound Energy, Inc.*, Docket UE-130583, Petition for an Accounting Order (April 24, 2013).
[16] *Id.*

In other words, the Commission should not allow PSE to create a regulatory asset for major maintenance. The Commission should deny the Company's accounting petition that asks for authority to create a regulatory asset.

Q. What major maintenance deferral amounts does PSE reflect in Company Adjustment 20?

A. PSE's Adjustment 20 applies a deferral for prepaid assets related to major maintenance; PSE's witness Katherine J. Barnard confirms this in her direct testimony.[17] The amounts to be deferred result in a regulatory asset amortization expense of $634,721, to be amortized over thirty-six months. The unamortized balance would accrue carrying charges, or otherwise earn a return.

Q. Is major maintenance expense an unusual expense for an electric utility company?

A. No. Major maintenance expense is an ongoing, substantial portion of an electric utility company's operating expenses. As with any ongoing expense, major maintenance expense could fluctuate over time, and therefore an adjustment may be included in the test period to normalize[18] the expense.

Q. Is the practice of normalization always appropriate?

A. Not necessarily. Normalization is appropriate only if the utility can prove the test period level of expense is unrepresentative of the rate year. For example, in PSE's

[17] Barnard, Exhibit No. KJB-1CT, at 32-35.
[18] Based on a five- or six-year average of expense.

last GRC, the Commission used the current test period expense for Major Maintenance rather than use a five-year average to normalize the expense.[19]

Q. How often do major maintenance events occur and how are the related expenses recorded?

A. For facilities such as Mint Farm, a major maintenance event happens approximately every 12,000 hours of use, based upon actual timing of the facilities capacity factor (hours run ÷ hours in the period).[20] Major maintenance expenses are often prepaid, but are trued up in following quarters based on the actual hours the plant was run during the quarter, compared to the billed run hours in the quarter.[21]

Typically, a utility records prepaid expenses at the time of maintenance event.

Q. Is there any accounting guidance or treatment for major maintenance as it pertains to the utility industry?

A. Yes. Accounting guidance for treatment of major overhauls and maintenance is provided by Accounting Standard Codification (ASC) 908-360-25 and Financial

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[19] *Utilities and Transp. Comm'n v. Puget Sound Energy, Inc.* Dockets UE-1111048 and UG-111049, Order 08 (May 7, 2012), at 74-77, ¶¶ 209-18, particularly ¶ 217: "*Commission Determination:* In PSE's most recently completed general rate case, the Commission rejected the proposed use of a five-year average for this category of expenses stating: "O&M is an ongoing expense and there is no evidence that the more recent historic data upon which PSE would have us rely requires any normalizing adjustments." We find on the basis of the record here that the same is true today. Considering PSE's changing use of its fleet of thermal production facilities, as described by Mr. Gould, we are not surprised that maintenance costs are trending upward. As PSE's use of intermittent renewable resources such as wind farms continues to increase in response to state-mandated RPS, the pattern of more frequent start-ups, shorter run times, and total run times at thermal facilities that facilitate wind integration may lead to a continuing trend of increasing O&M costs. Absent evidence of a change in this regard, it is reasonable to continue our reliance on the more recent test year data rather than averages of historic data." (Footnote omitted).

[20] *Puget Sound Energy, Inc.,* Docket UE-130583, Petition for an Accounting Order (April 24, 2013), at 3.

[21] *Puget Sound Energy, Inc.,* Docket UE-130583, Petition for an Accounting Order (April 24, 2013), at 4.

Accounting Standards Board's (FASB) Staff Position, No. AUG AIR-1 (FSP AIR-1).

Q. What guidance is provided by the Financial Accounting Standards Board in FSB AIR-1 regarding accounting for major maintenance?

A. FSP AIR-1 permits three methods of accounting for major maintenance-type costs: (1) direct expense; (2) built-in overhaul; and (3) deferral. However, it prohibits the "accrue-in-advance" method.[22] Furthermore, FSP AIR-1 changes the guidance on accounting for planned major maintenance activities found in the American Institute of Certified Public Accountants (AICPA) guide on audits of airlines, which companies in other industries have applied by analogy to their own circumstances.[23]

Q. What guidance is provided by the Accounting Standard Codification in ASC 908-360-25?

A. ASC 908-360-25 states "[t]he following accounting methods are permitted: a) the direct expensing method, addressed in subtopic 908-720 (see paragraph 908-720-25-3); b) the built-in overhaul method; and c) the deferral method." ASC 908-25-3 also states "paragraph 908-360-25-2 provides guidance on accounting methods for overhaul expenses. Most carriers recognize the cost of overhauls as expenses as they are incurred because, in the case of carriers with large fleets, such costs are relatively constant from period to period."[24]

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[22] FASB Staff Position, No. AUG AIR-1, Accounting for Planned Major Maintenance Activities, September 8, 2006, available at www.fasb.org

[23] AICPA Industry Audit Guide, Audits of Airlines, With Conforming Changes as of May 1, 2003.

[24] Available at www.fasb.org.

Q. What does Staff understand from this guidance?

A. This guidance shows that it is common for companies to defer and amortize these types of expenses.

Q. What accounting guidance does PSE say it follows major maintenance expenses?

A. PSE says it follows ASC 980-360 (regulated operations) when accounting for its major maintenance.[25]

Q. Does ASC 980-360 apply to major maintenance expenses?

A. No. By its terms, ASC 980-360 provides "guidance for plant abandonments and disallowances of costs of recently completed plants, as well as for the capitalization of an allowance for funds used during construction."[26] In other words, ASC 980-360 has nothing to do with major maintenance.

Q. Please describe Staff's Adjustment 20 related to major maintenance expense in this case.

A. Staff's Adjustment 20 allows recovery of the amortization expense by beginning amortization of the prepaid expense at the time of the major maintenance event and ending at the time of the next major maintenance event (approximately 36 months).[27]

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[25] *Puget Sound Energy, Inc.*, Docket UE-130583, Petition for an Accounting Order (April 24, 2013), at 4.
[26] Available at www.fasb.org, ASC 980-360-05 (overview and background).
[27] *Puget Sound Energy, Inc.*, Docket UE-130583, Petition for an Accounting Order (April 24, 2013), at 5.

Staff's adjustment removes the regulatory asset and the return on that asset that PSE had included.

Q. Should the Commission permit PSE to create a regulatory asset for major maintenance?

A. No, not for regularly occurring maintenance expenses. If the maintenance expenses were truly extraordinary, the Commission could approve a regulatory asset, but, if and only if, normalization or pro forma methods are not practical or appropriate. In this instance, PSE has not demonstrated that its major maintenance is extraordinary, or that normalization or pro forma methods are not practical or appropriate.

Q. Has PSE provided any other reason that justifies the creation of a regulatory asset for major maintenance?

A. No.

Q. Please summarize Staff's recommendation for Adjustment 20 related to major maintenance.

A. The Commission should require PSE to follow an acceptable method of accounting under GAAP, such as amortize the costs of a major maintenance event over the three years following the time of that event. Staff Adjustment 20 reflects this treatment. The Commission should reject in full the Company's accounting petition in Docket UE-130583.

C. Hydro Production Operations and Maintenance

Q. What is the nature of the adjustments PSE has made to test year hydro production O&M expense?

A. PSE has made several adjustments to test year hydro production O&M as discussed by Company witness Paul K. Wetherbee.[28]

Q. Does Staff object to any of PSE's adjustments to hydro O&M expense?

A. Yes. Staff objects to two adjustments the Company is proposing. First, Staff objects to the addition of $0.2 million to test year O&M to reflect the addition of two hydro journey worker positions at the Lower Baker Generation Station.[29] Second, Staff objects to the addition of $0.1 million to test year O&M to reflect labor cost associated with the instrument, controls & electrical technician position to support the new generation at Snoqualmie Falls.[30]

Q. What is the basis for Staff's objection to these pro forma adjustments to O&M?

A. Historical test year ratemaking is premised on the "matching principle" of accounting, where the relationship of revenues, expenses, and rate base is established. Pro forma adjustments are made to the test year for known and measurable changes with no offsetting effects,[31] thus maintaining the historical test

[28] Exhibit No. PKW-1CT, pages 47-48.
[29] Exhibit No. PKW-1CT, page 48, lines 10-13.
[30] Exhibit No. PKW-1CT, page 48, lines 6-7
[31] WAC 480-07-510(3)(iii).

year matching principle. The Company's prospective adjustments to staffing level violate this matching principle.

Q. Will pro forma adjustments to O&M *always* violate the matching principle?

A. No. A known and measurable change in a cost rate, such as a known change in the postage rate or a contracted wage level, when applied to the test year level of units, generally will not violate the matching principle. However, an adjustment to the test year level of units, such as prospectively adjusting the number of employees, will violate the matching principle. PSE's adjustments fall in this latter category.

Q. Please further explain "known and measurable" concept.

A. The known and measurable concept requires that the event that causes a change in revenue, expense or rate base must be *known* to have occurred during or after the historical 12 months of actual results of operations.[32] The actual amount of the change must also be *measurable*. Costs that are documented by actual expenditure, invoice, contract, or other specific obligation usually meet this test. Amounts that will not meet this test are estimates or amounts that are the product of a projection, budget forecast, or some similar exercise of judgment concerning future revenue, expense or rate base.[33]

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[32] *Utilities and Transp. Comm'n v. Avista Corporation,* Dockets UE-090134, UG-090135 and UG-060518, Order 10 (December 22, 2009), at ¶ 45.
[33] *Utilities and Transp. Comm'n v. Puget Sound Energy, Inc*., Dockets UE-090704 and UG-090705, Order 11 (April 2, 2010), at ¶ 26.

Q. Do the Company's proposed adjustments to O&M conform to this concept?

A. No. The two pro forma adjustments described above are not reflected in the test year and are derived completely from expectations of future staffing level. Both of the proposed adjustments are associated with facilities (Snoqualmie Project and Baker Project – Powerhouse) PSE did not expect to place into service until well after the filing date of this rate case. Given that the changes in O&M expenses for these projects are derived from expectations of future Company actions and projections of future expenditures, Staff does not recommend recovery at this time. If these expenditures become known and measureable, then they will be reflected in the next required PCORC filing in 2014.[34]

Q. What is the impact of Staff's recommendation?

A. Staff's recommendation reduces hydro O&M expense by $0.3 million.

D. Treasury Grants

1. Overview

Q. What is a Treasury Grant?

A. A Treasury Grant is money paid by the Treasury to utilities such as PSE, pursuant to Section 1603 of the American Recovery and Reinvestment Act of 2009 (ARRA).[35] These payments subsidize certain eligible renewable energy projects and for

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[34] *Utilities and Transp. Comm'n v. Puget Sound Energy, Inc.* Dockets UE-121373, UE-121697, UG-121705, UE-130137 and UG130138, Order 07 (June 25, 2013), at ¶ 194.

[35] Pub. L. No. 111-5, Div. B, tit. I, § 1603, 123 Stat. 115, 364 (February 17, 2009).

hydroelectric projects that provide incremental generation due to improvements as defined by the Internal Revenue Service Code (IRC) Section 45.

Treasury Grants are an alternative to Production Tax Credits (PTCs), which some companies have not been able to use in a timely fashion.

Formerly, ARRA required the Treasury to provide non-taxable cash grants of thirty percent (30%) of the eligible cost of a qualifying renewable investment[36] and the tax basis for accelerated tax depreciation was reduced by one half of the grant received.[37]

Q. Has PSE received Treasury Grant money?

A. Yes. PSE received treasury grant monies for the White Horse Expansion (WHE) and Lower Snake River Phase 1 (LSR Phase 1) projects. The Company also expects to receive Treasury Grants for Snoqualmie Project and Baker Project in the near future.

Q. How does PSE currently treat this money for ratemaking purposes?

A. Currently, PSE passes Treasury Grant monies for the WHE and LSR Phase 1 projects back to customers through a credit in Tariff Schedule 95A. Therefore, the Treasury Grants are not reflected in the PCORC, other than to include the impact of the tax basis reduction in the determination of tax depreciation expense.

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[36] *Id.*

[37] IRC 48(d)(3); 26 U.S.C. § 48(d)(3).

Q. How should the Commission treat Treasury Grants for PSE?

A. The Commission should order PSE to: (1) Discontinue the practice of using Schedule 95A for passing back Treasury Grants to customers in the form of rate credits for the WHE and LSR Phase 1 once they are fully amortized; and (2) Defer all future Treasury Grant amounts as a regulatory liability and accrue interest at the Company's authorized rate of return until the next available GRC or PCORC. In that GRC or PCORC the accrued balance should be credited to rate base as a direct reduction to the associated plant balance. Staff recommends this treatment for the Snoqualmie and Baker Projects.

Q. Please list the reasons why Staff proposes to change the use of Treasury Grant dollars from a rate credit to a direct reduction to plant in service.

A. Staff proposes rate base treatment for the following reasons:

a) This treatment for Treasury Grant monies is now allowed due to an amendment to the ARRA, under the National Defense Authorization Act for Fiscal Year 2012 (NDAA).[38]

b) Staff's recommendation is consistent with the understanding that the Treasury Grants were meant to reduce the cost of the plants, and it is consistent with Staff's and the Company's prudency recommendation for Snoqualmie Project and Baker Project.

c) Staff's proposed treatment properly matches the life of the Treasury Grant with the life of the associated plant.

[38] The amendment occurred through Section 1096 of the National Defense Act for Fiscal Year 2012, H.R. 1540, 112th Congress, 1st Session.

d) The current treatment of Treasury Grants creates intergenerational inequity by passing back the value of the Treasury Grant to ratepayers faster than the associated tax treatment.

e) Staff's proposal to use Treasury Grants to offset rate base on the Company's books eliminates the administrative burden associated with annual tracker filings in the future.

f) Problems involving the alignment of costs and benefits arise from the Commission choosing to pass back a grant through a separate tracker. Because PTCs accumulate with every megawatt-hour of generation, a tracking mechanism was appropriate to accommodate the variation that might occur over time. The ensuing credits are used to offset the taxes of the utility and can be taken for up to ten years. The only problem with PTCs is that a company would need to have taxable income to take advantage of the tax credits. In addition, is the way costs are collected, in part from demand charges and in part from energy charges, while the benefits in a tracker are given back strictly through energy charges. Thus, larger energy users receive a larger portion of tracker benefits compared to the actual costs they pay. Allocating solar and wind resources and related expenses on an energy-only basis cures this problem by removing the costs being collected through a demand allocation; thus, ensuring that costs are collected and benefits are received in the same manner, through energy charges.

2. Current Status and Treatment of Treasury Grants

Q. What Treasury Grants has the Company applied for?

A. To date, PSE has applied for and received two Treasury Grants, for WHE and LSR Phase 1. In the near future, the Company will be applying for more Treasury Grants for the Snoqualmie and Baker Projects.

Q. Please explain the Commission's treatment of Treasury Grants.

A. The treatment of Treasury Grants was discussed in Dockets UE-111048 and UG-111049,[39] and Docket UE-122001.

In Dockets UE-111048 and UG-111049, the Commission did not determine the appropriate treatment of Treasury Grants because PSE had not yet received the monies related to its investment in LSR. However, the Commission determined that PSE's next Schedule 95A filing would be the proper proceeding to address the treatment of Treasury Grants.[40]

PSE's next Schedule 95A filing was Docket UE-122001, in which the Commission decided to use Schedule 95A to pass back the Treasury Grant monies that PSE received through rate credits over a ten (10) year amortization period for WHE and LSR.

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[39] *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket Nos. UE-111048 and UG-111049, Order 08 (May 7, 2012) at ¶¶ 172-176.

[40] *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket Nos. UE-111048 and UG-111049, Order 08 (May 7, 2012) at ¶ 176.

3. The Matching Issue and Intergenerational Inequity

Q. Does the current rate credit mechanism for refunding Treasury Grants in Schedule 95A match relative costs and benefits?

A. No. Schedule 95A returns Treasury Grant money through energy charges, while the fixed costs of the related assets are collected by the Company largely through demand charges. Thus, larger energy users receive a larger portion of the tracker, and correspondingly a larger portion of the Treasury Grant monies compared to the actual costs they pay in rates.

Q. Does Staff's proposed treatment of Treasury Grants (using that money as a direct offset to the plant balances the Grants are associated with) more accurately align costs with their appropriate benefits?

A. Yes. Staff's proposal passes the entire Treasury Grant back to all customers in the form of reduced depreciation expense and fixed asset recovery, return of and return on rate base respectively. Furthermore, Staff's proposal eliminates inequities in allocation of this benefit, compared to the costs, because the reduction in expenses is based upon the allocation factor established in the Company's last GRC.

Q. Does the current mechanism for refunding Treasury Grants in Schedule 95A, appropriately match the timing of expenses to revenues?

A. No. As I explained earlier, Schedule 95A was set up to return to ratepayers the benefits of PTCs received by the Company. Because PTCs accumulate with every megawatt-hour of generation, a tracking mechanism is appropriate to accommodate the variation that might occur over time. The ensuing credits are used to offset the Federal Income Tax (FIT) of the utility and can be taken for up to twenty (20) years after the year in which PTCs were produced.[41] The only problem with PTCs is that the Company would need to have taxable income to take advantage of the tax credits.

By contrast, Treasury Grants are a one-time cash payment from the U.S. government, to encourage investment in specific categories of generating facilities assets. A Treasury Grant is processed much more quickly after the utility incurs the cost, typically sixty (60) days from the receipt of the application, and after the plant is in service.[42] The Treasury Grants are presented in the form of liquid assets (i.e., cash or revenue) that serve as direct reimbursements of capital outlays.

It is important to emphasize that the Treasury Grant program requires that the project be completed (i.e., all of the costs incurred) before any reimbursement may take place. In short, PTCs and Investment Tax Credits (ITCs) differ greatly from Treasury Grants due to their timing requirements for eligibility, and a different regulatory treatment is therefore warranted.

Q. Does Staff's proposed treatment of Treasury Grants more accurately match the timing of revenues with expenses?

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[41] PSE's response to Commission Staff Data Request 8.

[42] United States Department of Treasury's Program Guidance entitled "*Payments for Specified Energy Property in Lieu of Tax Credits under the American Recovery and Reinvestment Act of 2009"* (July 2009/Revised March 2010/Revised April 2011), at page 3, lines 24-27. *See also* my Exhibit No. CTM-6.

A. Yes. Schedule 95A passes the value of the Treasury Grant back to ratepayers faster than the Company recovers the costs of the asset and the tax treatment of the asset; therefore, creating an intergenerational inequity.

4. Tax Treatment of PTCs and ITCs is Different than Treasury Grants

Q. Are Treasury Grants treated differently on a tax basis from PTCs and ITCs?

A. Yes. PTCs and ITCs are direct offsets to current and future FIT liabilities. They may, or may not, be fully realized on the tax return of the year where the expense are actually incurred; this occurs if a company has too low of a tax liability to fully receive the complete credit. PSE typically falls into this category.[43]

By contrast, a Treasury Grant is an immediate percentage reimbursement of capital expenditures and it reduces the depreciable tax basis of the plant by fifty (50) percent of the Treasury Grant's value. Treasury Grants, however, are not treated as income for FIT purposes and therefore only have implications for the depreciable base of the plant.

This basis reduction is accounted for within the Company's workpapers under "Adjustment for Flow-thru taxes;"[44,45] therefore, ratepayers solely bear the cost of receiving the Treasury Grants in the form of a reduced plant basis eligible for depreciation.

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[43] PSE's response to Commission Staff Data Request 8.

[44] Barnard, workpapers titled "KJB-WP 04.04 – Snoqualmie Upgrad," tab "Lead Sheet," row 22.

[45] Barnard, workpapers titled "KJB-WP 04.06-9.07 Baker Adj & Deferral SUPP," tab "Lead Sheet Plant Adj," row 20.

5. ARRA Permits Treasury Grants to be Used to Offset Rate Base

Q. Are Treasury Grants subject to any other rules?

A. Yes. Through a series of provisions in ARRA and the IRC, plus guidance from the Treasury, the United States government initially required utilities to normalize Treasury Grants received under ARRA. Normalization allowed PSE to provide customers with one of the following: (1) an offset to rate base for the unamortized balance of the Treasury Grant; or (2) the amortization of the Treasury Grant as a reduction to cost of service.

PSE chose the second method. The Commission approved that treatment in December 2009 in Docket UE-091570[46] for WHE. In doing so, the Commission stated:

> However, the Commission and its Staff reserve the right to provide alternative methodologies for the treatment of the Treasury grants in future proceedings that may differ from the Company's proposed accounting and normalization treatment based on new analysis, new information becoming available, or based on new guidance being provided by the Internal Revenue Service or Treasury.[47]

PSE lobbied[48] for changes within the NDAA, which amended ARRA to eliminate normalization requirements for the Treasury Grants. According to PSE, the Company initiated a legislative effort to "correct" the law to eliminate normalization

[46] *Puget Sound Energy, Inc.*, Petition for an Accounting Order, Docket UE-091570, Order 01 (December 10, 2009) – Regarding the treatment of U.S. Treasury Grant to be received under Section 1603 of the American Recovery and Reinvestment Act of 2009 associated with the WHE.
[47] *Id*. at ¶¶ 3 and 14.
[48] PSE's Federal Incentive Tracker Tariff Filing under Docket UE-120277, PSE Initial Brief at ¶ 34. This effort, according to PSE, began in May 2009. Stipulation of Facts at ¶ 7, Attachment A at Marcelia, page 72, line 17.

requirements for ARRA Section 1603 grants and that "correction" was signed into law as Section 1096 of NDAA.[49]

Q. What is the legislative intent for the Treasury Grants and these changes?

A. The stated intent of the Treasury Grants is to "reimburse eligible applicants for a portion of the expense of such [energy] property."[50] Treasury Grants are specifically exempt from IRC 46(f) regulations, which outline the rules of normalization. In other words, normalization is no longer required.

Congress therefore intended these Treasury Grants to be one-time reimbursements of incurred capital expenditures. Additionally, the law outlines the use of Treasury Grants to be assigned to third-parties financial institutions. This directly implies the use of Treasury Grants to be capital in-flows for construction purposes.

Q. As you understand it, is Staff's recommendation to use Treasury Grants as a reduction to the plant balance of the related plant permitted by NDAA?

A. Yes. Staff's recommendation implements a provision in the NDAA that eliminated normalization requirements within ARRA. The amendment stated:

a) In General – The first sentence of section 1603(f) of the American Recovery and Reinvestment Tax Act of 2009 is amended by inserting "other than subsection (d)(2) thereof" after "section 50 of the internal Revenue Code of 1986".

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[49] PSE's Federal Incentive Tracker Tariff Filing under Docket UE-120277, Stipulation of Facts at ¶ 7, Attachment A at Marcelia, at page 73, lines 12-15 and at page 74, line 6.

[50] U.S. Department of Treasury's Program Guidance entitled "*Payments for Specified Energy Property in Lieu of Tax Credits under the American Recovery and Reinvestment Act of 2009"* (July 2009/Revised March 2010/Revised April 2011), at page 2, lines 4-5. *See also* my Exhibit No. CTM-6.

b) Effective Date – The amendment made by this section *shall take effect as if included in section 1603 of the American Recovery and Reinvestment Tax Act of 2009*.[51] (Emphasis added).

Section 1096 of the NDAA is supported by the legitimate and rational legislative purpose of eliminating normalization requirements of Treasury Grants for ratepayer benefit.

Q. Does the Commission's inclusion of Snoqualmie Project and Baker Project facilities in rate base for ratemaking purposes justify Staff's proposed treatment of the related Treasury Grants?

A. Yes. Ratepayers will provided and are continuing to provide, all of the funds necessary for PSE to recover both the operating expenses of the Snoqualmie Project and Baker Project, and a return of and on the Company's investment in those facilities. Therefore, it is fair and reasonable for ratepayers to receive the full benefit of the Treasury Grant as a direct offset to the associated plant balances. Staff's method matches costs and benefits in accordance with fundamental principles of ratemaking.

Q. How should the Commission treat Treasury Grants PSE receives for these future eligible projects?

A. The Commission should direct PSE to use future Treasury Grant amounts as a direct rate base offset to the capital costs of the related asset. In order to accomplish this

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[51] Section 1096 of the National Defense Authorization Act for Fiscal Year 2012, H.R. 1540, 112th Congress, 1st Session.

rate base treatment for future Treasury Grants, PSE should be required to defer the amount under RCW 80.80.060(6) for all Treasury Grant as a regulatory liability, and accrue interest at the Company's authorized rate of return until such treatment can be applied. This deferred treatment is consistent with prior treatment given to the Company for regulatory assets and fixed plant. I note the Company has been willing to apply such treatment to Treasury Grants in the past.[52]

6. Staff's Proposed Treatment of Treasury Grants is Reasonable

Q. How would Staff's approach affect the Company?

A. Staff's approach treats stockholders and ratepayers equally. Currently, stockholders pay ratepayers interest on the Treasury Grants, while ratepayers pay interest to stockholders on the plant balance for Snoqualmie Project and Baker Project. Staff's approach eliminates this passing back and forth of interest on a plant balances related to the Treasury Grants.

Q. Is the PCORC the appropriate forum for discussing the treatment of Treasury Grants?

A. Yes. The accounting treatment of Treasury Grants has important impacts on the fixed components of power costs. Staff's recommendations are consistent with the PCORC's treatment of all other fixed power costs. Staff's recommendation to use Treasury Grants as a direct rate base offset to reduce plant balance, deferred income

[52] *Id.*, at ¶ 175 – the Commission states that the Company "does not object to deferring the LSR Treasury Grant and reflecting the appropriate ratemaking treatment, with any associated impact of the Wild Horse Treasury Grant, in its [forthcoming] Schedule 95A filing,.."

tax liability, accumulated depreciation, and operating expenses. This is consistent with the PCORC's required treatment of other fixed costs. Furthermore, Treasury Grants are unequivocally related to their associated plants. Based on the matching principle of accounting, it is necessary to keep the treatment of the benefits of an asset in the same proceeding as its costs.

Q. Has Staff included in its adjustments the proposed treatment of Treasury Grants for both the Snoqualmie Project and Baker Project?

A. No. Staff has not included at this time an adjustment reflecting the expense and rate base reduction from the Treasury Grant associated with the Snoqualmie Project and Baker Project.

Q. Please summarize Staff's recommendation to the Commission regarding Treasury Grants.

A. For the reasons set forth above, the Commission should adopt the Staff recommendation that Treasury Grants as a direct rate base offset to reduce plant balance, accumulated depreciation, and operating expenses. Staff's recommendation is consistent with the NDAA and sound principles of ratemaking, including the matching principle and intergenerational equity.

The Commission should direct the Company to defer the Treasury Grant associated with the Snoqualmie Project and Baker Project under RCW 80.80.060, and to include them as a direct rate base offset to reduce plant, accumulated depreciation, accumulated deferred income taxes, and depreciation expense in the Company's next PCORC.

IV. CALCULATION OF POWER COST RATE

Q. Has Staff prepared an exhibit that identifies the adjustments used to determine the new Power Cost Rate?

A. Yes. My Exhibit No. CTM-2 lists each adjustment used to determine the new Power Cost Rate. This exhibit summarizes and provides a breakdown of each adjustment. The adjustments Staff contests are identified on that exhibit as italicized numbers with shaded headers. I discuss each contested adjustment later in my testimony.

Q. Please explain Staff's general approach to determine power costs in this case.

A. To determine power costs, Staff pushes forward all of the Company's adjustments as I explain in Section III.A of my testimony, if the information was available to do so, to the rate year and then using the relationship of normalized test year delivered load to rate year delivered load (production factor) to restates those costs back to test year levels. This approach realigns the rate year in accordance with the procedural schedule that would implement new rates as of December 1, 2013.

Because the Company used a rate year ending one month earlier than Staff's rate year, all the adjustments are contested to the extent of that difference. In addition, certain adjustments will have other specific modifications that are addressed and explained by other Staff witnesses.

A. Uncontested Adjustments

Q. Please describe each of the uncontested adjustments presented in Exhibit No. CTM-2.

A. The adjustments are:

1. Remove Wild Horse Solar (Adjustment 10)

This adjustment removes the effects of the solar project at Wild Horse. This adjustment decreases rate base by $2,805,550 and expense by $492,352.

2. Remove Tenaska (Adjustment 11)

This adjustment removes the amortization and rate base return that were included for three months of the test period associated with the Tenaska Regulatory Asset.[53] This adjustment decreases rate base by $1,213,374 and expense by $10,281,888.

3. Property Taxes (Adjustment 13)

The Company had this adjustment as a place holder for property tax.

4. Conversion Factor (Adjustment 25)

This adjustment is used to adjust the net operating income deficiency or surplus for revenue sensitive items to determine the total revenue requirement. The revenue sensitive items are the Washington State utility tax, the Commission's annual filing fee, and bad debts. The conversion factor used in this proceeding is 95.4994 percent.

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[53] *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-031725, Order 14 (May 13, 2004) at ¶¶ 25-29.

B. Contested Adjustments Strictly Due to Rate Year

Q. Please describe each of the contested adjustments presented in Exhibit No. CTM-2 strictly due Staff's use of a rate year that is consistent with implementing new rates as of December 1, 2013.

A. The adjustments are:

1. Montana Energy Tax (Adjustment 2)

This adjustment compares the forecast generation of the Colstrip plants at the current Montana tax rate to the actual tax expensed in the test year. This adjustment increases expense by $918,448.

2. Lower Snake River Project (Adjustment 3)

This adjustment restates a full rate year of plant balance, accumulated depreciation, deferred income tax liability, and operating expenses amounts to properly recognized LSR plant as allowed in the Company's most recent GRC.[54] This adjustment increases rate base by $89,361,374 and expense by $21,503,819.

3. Bonneville Exchange Power (Adjustment 15)

This adjustment trues up the production related prepaid transmission regulatory assets, net of deferred federal income taxes, to its projected rate year AMA balance. This adjustment decreases rate base by $5,134,690 and expenses by $528,478.

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[54] *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08 (May 7, 2012).

4. Regulatory Assets – White River Project (Adjustment 16)

This adjustment trues up the production related regulatory assets, net of deferred federal income taxes, to its projected rate year AMA balance. This adjustment decreases rate base by $2,049,566 and expenses by $210,948.

5. Plant Deferrals (Adjustment 17)

This adjustment pro forms rate base and amortization related to the plant deferrals associated with resources approved in prior proceedings to rate year levels. This adjustment decreases rate base by $4,637,463 and increases expense by $1,342,133.

PSE's deferral for LSR was approved recovery over four years.[55] Because the actual deferral amount of $17.9 million was less than the $18.3 million approved, the monthly amortization amount for LSR was adjusted from $381,716 to $374,737, effective with the rates to be approved in this proceeding on December 1, 2013, to maintain the approved amortization period of 48 months.

6. Capacity Payments on Westcoast Pipeline (Adjustment 18)

This adjustment trues up rate base related to capacity payments made to PSE by FB Energy and BNP Paribus.[56] This adjustment increases rate base by $1,280,411 and expense by $131,784.

7. PUD Contract Initiation Payment & Security Deposit (Adjustment 19)

This adjustment trues up rate base and amortization related to a security deposit and initiation payment made under the Chelan Public Utility District (PUD) power sales agreement for the output of the Rock Island and Rocky Reach Hydroelectric Projects

[55] *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08 (May 7, 2012) at ¶¶ 300-09.
[56] The Commission approved these payments in Docket Nos. UE-082013 and UE-100053.

to rate year levels. This adjustment decreases rate base by $11,001,713 and expense by $541,658.

8. Hedging Line of Credit (Adjustment 22)

This adjustment pro forms in the commitment costs associated with PSE's line of credit for hedging. The Commission approved recovery of costs associated with a line of credit supporting hedging transactions in the PCA and Purchased Gas Adjustment (PGA) mechanisms.[57] This adjustment decreases expenses by $52,144.

9. Temperature Normalization (Adjustment 24)

This adjustment presents the difference in temperature between the test year and a normal temperature year. This adjustment deducts 113,565 MWhs from the actual load after adjusting for system losses.

C. Contested Adjustments Due to Rate Year and Other Issues

Q. Please describe each of the adjustments presented in your Exhibit No. CTM-2 that Staff contests not only due to the rate year, but due to other reasons as well.

A. The adjustments are:

1. Power Costs (Adjustment 1)

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 production factor. Staff witness David C. Gomez discusses these projected costs that are a pro forma adjustment to the test year costs, the addition of Electron and its

[57] *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.,* Dockets UE-060266 and UG-060267, Order 08 (January 5, 2007) at ¶ 34.

corresponding components, while removing the Electron power purchase agreements (PPA).

Staff witness Edward J. Keating discusses the removal of Cedar Hills. I reduce the hydro production O&M, as discussed in my testimony in Section IV.B. These adjustments are reflected in the power cost adjustment; however, due to the nature of determining power costs are run, the final effect of Staff's power cost related adjustments will not be reflected until the compliance filing,[58] which should include the appropriate updates discussed in Staff witness David C. Gomez's testimony.

The total power cost adjustment decreases costs by $135,720,995, not taking into account the results of the final power cost update.

2. Snoqualmie Falls Project Upgrades (Adjustment 4)

This pro forma adjustment presents the plant balance, accumulated depreciation, deferred income tax liability, and operating expenses amounts associated with the Snoqualmie Project up to and including April 25, 2013. The Snoqualmie Project includes Power Plants 1 and 2, and a Diversion Dam. All costs after that date were removed.

Staff witness Juliana M. Williams discusses the reasons for the cutoff period and removal of all costs associated after that date. This adjustment increases rate base by $235,974,393 and expenses by $34,223,697.

[58] Staff had a discussion with the Company to update the filing to reflect the procedural schedule's rate year, and the Company responded that it would take several weeks, if not longer to do so. Therefore, refusing to provide the Company's supplemental filing updated to reflect the procedural schedule.

3. Snoqualmie Falls Project Deferral (Adjustment 5)

This adjustment includes the estimated rate year for plant balance, accumulated depreciation, deferred income tax liability, and operating expenses amounts for deferred costs associated with Diversion Dam and Plant 2. Plant 1 is not eligible for deferral at this time because it is not in service as of April 25, 2013.

Staff witness Juliana M. Williams discusses the reasons for the cutoff period and removal of all costs associated after that date. This adjustment increases rate base by $6,287,245 and expenses by $2,391,541.

4. Lower Baker Project Upgrades (Adjustment 6)

This adjustment includes plant balance, accumulated depreciation, deferred income tax liability, and operating expenses amounts associated with the Baker Project up to and including April 25, 2013. The Baker Project additions include the Lower Baker Floating Surface Collector (FSC) and the Lower Baker Powerhouse (LBP). All costs after that date were removed.

Staff witness Juliana M. Williams discusses the reasons for the cutoff period and removal of all costs associated after that date. This adjustment increases rate base by $124,718,619 and expenses by $16,350,136.

5. Lower Baker Project Deferral (Adjustment 7)

This adjustment was the Company's estimated rate year amortization expense and net rate base amount for deferred costs associated with the LBP. Staff eliminated this adjustment because LBP did not begin operation until July 24, 2013, and because it was not in service by April 25, 2013, it is not eligible for deferral at this time.

Staff witness Juliana M. Williams discusses the reasons for this removal.

6. Ferndale Generating Station (Adjustment 8)

This adjustment pro forms for plant balance, accumulated depreciation, deferred income tax liability, and operating expenses amounts associated with the Ferndale Plant. This adjustment also includes the Asset Retirements Costs (ARC) and Asset Retirement Obligations (ARO). Staff changed the ARC and ARO discounted present value balance to 1,562,307,[59] instead of 1,564,370. These amounts represent recovery of the costs of restoring the site back to original condition before the lease ends in 2041.

Staff witness Juliana M. Williams's discusses ratemaking treatment of pro forma rate base additions. This adjustment increases rate base by $73,111,891 and expense by $10,699,524.

7. Ferndale Deferral (Adjustment 9)

This adjustment includes the estimated rate year for plant balance, accumulated depreciation, deferred income tax liability, and operating expenses amounts for deferred costs associated with Ferndale.

Staff witness Juliana M. Williams discusses ratemaking treatment of pro forma rate base additions related to Ferndale Plant deferrals. This adjustment increases rate base by $15,672,263 and expense by $5,996,887. Property taxes are included in this adjustment, due to the Commission approval of the property tax tracker;[60] these expenses should not be included in the PCORC, too.

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[59] PSE's response to Commission Staff Data Request 39.

[60] *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-130137 and UG-130138, Order 07 (June 25, 2013) at ¶ 183.

8. Sale of Electron Project (Adjustment 12)

This adjustment keeps in the AMA balances of the Electron Project plant, accumulated depreciation and deferred income taxes from the test year rate base and removes the unrecovered regulatory asset and expenses related to the sale of Electron.

Staff witness David C. Gomez discusses the reasoning for the Electron plant stay in rate base until the sale is formalized. This adjustment decreases rate base by $7,528,133 and expense by $836,094.

9. Property Insurance (Adjustment 14)

This adjustment includes Ferndale property insurance that was not present in the test year, adjusts property insurance for the Baker and Snoqualmie Falls projects, adds Electron property insurance, and restates the remaining production property insurance to current levels.

Staff witness David C. Gomez discusses the reason for the addition of Electron property insurance. This adjustment increases expense by $101,511.

10. Other Regulatory Assets (Adjustment 20)

This adjustment trues up rate base and amortization related to regulatory assets which were included and approved for recovery in prior rate proceedings, with the exception of an accounting treatment for payments for major maintenance PSE made under an existing Long Term Service Agreement with GE for PSE's Mint Farm Facility, which the regulatory asset was removed and amortize the costs following the time of the event until the next event. The resulting amortization of $634,721 shown on line 22 of the adjustment is the impact of this calculation on expense before applying the production adjustment factor.

I am responsible for this adjustment, which decreases rate base by $2,854,621 and expense by $1,569,651.

11. Prepaid Transmission & Deferred Carrying Charges (Adjustment 21)

This adjustment 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.

Staff witness Joanna Huang discusses the recommendation in response to the Company's petition asking for an order authorizing the transfer of the purchased assets and its accounting treatment for the balance of the regulatory asset associated with the BPA substation loan that was assigned to Lower Snake River Phase 2. This adjustment decreases rate base by $28,393,533 and increases expense by $608,984.

12. Production Adjustment (Adjustment 23)

This adjustment pro forms the production related rate base and expenses that have not been included in 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.

Staff made one adjustment to reconcile the differences between the Company's financial statements and Client Data Analysis Retrieval System (CDARS).[61] The test year delivered load of 21,321,495 MWhs has been adjusted by the temperature normalization, reconciled for the inconsistency between CDARS and

[61] PSE's response to Commission Staff Data Request 50.

financial statements, and removal of the test year load for the sale of PSE assets to Jefferson County PUD No. 1.

The resulting adjusted test year delivered load of 20,912,761 MWhs divided by the rate year delivered load of 21,288,639 MWhs results in a production factor of 1.766 percent. When applied to the production costs and rate base in this adjustment, it decrease rate base by $44,888,3394 and expense by $7,539,496.

V. POWER COST RATE AND REVENUE REQUIREMENT

Q. Have you prepared an exhibit that describes the impact of the pro forma adjustments on the Power Cost Rate?

A. Yes. My Exhibit No. CTM-3 shows the impacts of the above adjustments on the Power Cost Rate, for known and available information to Staff. The costs are allocated between fixed and variable, and the total costs are adjusted for revenue sensitive items. The total costs of $1,265,090,766 are divided by the test year delivered load of 20,912,761 MWhs to calculate the new Power Cost Rate of $63.345 per MWh after being grossed up for revenue sensitive item.

Staff proposes to decrease the Power Cost Rate from $64.099 to $63.345 per MWh. This compares to the Company's proposal to increase the Power Cost Rate from $64.099 to $64.120 per MWh.

Q. Please explain how Staff calculated the revenue requirement.

A. Staff calculated the revenue requirement using the difference between the current Power Cost Rate and Staff's proposed Power Cost Rate, after making the adjustments I discussed earlier, and grossed up for revenue sensitive items. This calculation is shown in my Exhibit No. CTM-4. The result of Staff's calculation is a decrease in revenue requirement by $15,775,123. This compares to the Company's proposal to increase the revenue requirement by $491,934.

This change in rates results in an average decrease of approximately 0.77%. Staff discusses how this revenue impact is allocated to each of the customer classes in the next section of my testimony.

VI. REVENUE ALLOCATION AND RATE DESIGN

Q. Please summarize how the proposed revenue change to the Power Cost Rate should be allocated to customer classes.

A. The PCA procedures require that changes in the Power Cost Rate be spread to customer classes based upon the peak credit methodology used in computing the revenue allocation methodology in PSE's most recent GRC.[62] Therefore, Staff applied the peak credit methodology from the last GRC to determine the amount to be allocated to each rate class. The allocation to rate classes is shown in my Exhibit No. CTM-5.

[62] *Utilities & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08 (May 7, 2012).

Q. Have you prepared an exhibit describing the calculation of Schedule 95 Rates?

A. Yes. My Exhibit No. CTM-5 shows the calculation of the PCA rates in Schedule 95, for each rate class. It calculates Schedule 95 rates for each class by dividing the allocated costs by the weather adjusted kWh for each class for the test year.

Q. Please summarize the impacts of the proposed Schedule 95 rates.

A. The results show a decrease percentage impact in the range of 0.72 percent to 1.15 percent. Residential customers receive approximately half of the overall revenue reduction, as shown in my Exhibit No. CTM-5.

Q. Does this conclude your testimony?

A. Yes.