Exhibit No. ___CT (DCG-1CT)
Docket UE-130617
Witness: David C. Gomez
Redacted Version

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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

TESTIMONY OF

David C. Gomez

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Power Supply Issues

August 14, 2013

CONFIDENTIAL PER PROTECTIVE ORDER
Redacted Version

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David C. Gomez. 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 the Assistant Power Supply Manager in the Energy Section of the Regulatory Services Division. I attained this position on July 1, 2012. Prior to my current position, I was the Deputy Assistant Director in the Solid Waste and Water Section of the Regulatory Services Division.

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

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

Q. Please state your educational and professional background.

A. I hold a Bachelor of Arts degree in Business from Hamline University and a Masters of Business Administration degree from the University of Saint Thomas; both universities are located in Saint Paul, Minnesota.

Before joining the Commission, my relevant professional experience consisted of 22 years in a variety of fields, including management, contracting, supply chain, procurement, operations and engineering. I hold professional certifications from the Institute for Supply Management (ISM); APICS - The Association for Operations Management; Universal Public Procurement Council (UPPC); and QAI Global Institute (Software Testing).

While employed at the Commission, I have performed accounting and financial analysis of tariff and other filings of Commission-regulated utility and transportation companies, as well as legislative and policy analysis. I presented testimony for Commission Staff (Staff) in Docket UE-121373, regarding the Coal Transition Power Purchase Agreement between Puget Sound Energy, Inc. ("PSE" or the "Company") and TransAlta Centralia Generation LLC and in Docket UE-130043, PacifiCorp's 2013 general rate case. I have also presented Staff recommendations to the Commission at numerous open meetings, and worked on various rulemakings undertaken by the Commission.

II. SCOPE AND ORGANIZATION OF TESTIMONY

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

A. The purpose of my testimony is to address rate year power costs for the period December 2013 through November 2014 (Staff's "rate year"). PSE's proposed rate year is November 2013 through October 2014 (rate year). Staff witness Mr. Mickelson testifies on the rate year issue.[1]

[1] Staff adjustments to power costs referenced throughout this testimony is expressed in PSE's proposed rate year amounts. As a result, Staff's adjustment amounts in this testimony will change some, but not significantly, when the final effect of Staff's power cost related adjustments are reflected in the Company's compliance filing after the Commission has rendered its final order.

The Company's proposed updated rate year power costs of $742.8 million represent an approximate $4.2 million increase from the original filed power costs of $738.6 million, and a $67.3 million decrease from the amounts included in current rates.

In my Exhibit No. DCG-2C, I provide a summary of my recommended adjustments to the Company's proposed rate year power costs at the expense level. My adjustment reduces the Company's proposed updated rate year power costs of $742.8 million by $1.4 million. The results of these adjustments on revenue requirement are reflected in Staff witness Mickelson's Exhibit No. CTM-2, Adjustment 1.[2]

Q. As you mentioned, Staff proposes a rate year starting one month later than PSE's proposed rate year. Have you calculated the impact of that difference on "Not-in-Model" and AURORA Model power costs?

A. No. I cannot determine the overall effect of the rate year difference and the update to gas and electric market prices, new contracts, changes to 'Mark-to-Market" costs, etc. However, given the relative stability of recent gas prices, I expect such changes to rate year power costs to be minimal.

Q. How is your testimony organized?

A. My testimony is organized into two general areas – first, those projected rate year power cost issues related to what is called "Not-in-Model" adjustments proposed by

[2] Of the total $742.8 million, $499.7 million is modeled in Aurora and $243.1 million are "Not-in-Model" costs.

the Company, and second, those issues that affect the inputs to and results of the Company's AURORA hourly dispatch model. As indicated in Table 5 of the Direct Testimony of David E. Mills, Exhibit No. DEM-1CT, total projected rate year power costs consists of the sum of AURORA and "Not-in-Model" costs.

I also make recommendations regarding how the Commission can address Staff's proposed change in the rate year from the perspective of projected power costs.

Q. What "Not-in-Model" power cost issues do you address in your testimony?

A. I address the testimony of Company witness Tom A. DeBoer in Exhibit No. TAD-1T, regarding the effect of PSE's renewal of several Bonneville Power Administration (BPA) transmission contracts, along with the effect of rate changes resulting from the decision in BPA's 2014 rate case. In addition, I respond to Company witness Matthew D. Rarity's testimony in Exhibit No. MDR-1CT, addressing PSE's wind integration costs for the rate year.

Q. Please define what the AURORA model power supply costs are in this case.

A. AURORA model power supply costs are those rate year power costs determined by using the Company's AURORA hourly dispatch model. In its case, the Company used a rate year representing the period from November 1, 2013 through October 31, 2014.

The proposed AURORA model rate year power costs are best summarized by looking at page 1 of the Confidential Exhibit No. DEM-4C of David E. Mills and his subsequently revised supplemental Confidential Exhibit No. DEM-7C. In the Company's supplemental case, the proposed "In-the Model" power costs are indicated under the sub-heading "AURORA" in column labeled 2013 PCORC (Nov13- Oct13). The Company's proposed AURORA costs amount to approximately $499.712 million for the Company's proposed rate year.

Q. Please describe Staff's examination of power costs from the AURORA Model.

A. Staff examined the inputs associated with the model runs PSE used to arrive at its rate year power costs, including updates, consistent with the Commission's order in PSE's 2011 general rate case (2011 GRC), which requires the Company to reflect the most recent operating and market conditions.[3]

PSE's supplemental testimony included, among other things, an adjustment to AURORA to add power delivered under the terms of power purchase agreement (Electron PPA) between PSE and Electron Hydro LLC (Electron Hydro).[4] For the rate year, AURORA modeled 51,501 MWh of electricity from the Electron Project, resulting in a total rate year cost of just under $3 million.[5]

In its initial filing, the Company included the costs of the Electron PPA in its "Not-in-Model" power cost numbers, at an annual expense amount $1.2 million higher than what the Company later modeled in AURORA.

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[3] *Utilities and Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08, ¶262, (May 7, 2012).
[4] On June 6, 2013, PSE filed with the Commission an application in Docket UE-131099 pursuant to RCW 80.12 and WAC 480-143, for authority to sell and transfer certain assets related to the Company's Electron Hydroelectric Project (Electron Project) to Electron Hydro. Along with approval of the sale, the Company sought approval from the Commission of its proposed accounting and ratemaking treatment to allow PSE to earn a return on and of the unrecovered costs and amortization expense of the Electron Project. The Commission issued an order consolidating the application with this docket; UE-130617.
[5] Mills Exhibit No. DEM-7C.

Q. What issues regarding power costs from the AURORA Model do you address in your testimony?

A. In addition to the rate year power cost impact of the Electron PPA, my testimony also includes an analysis and recommendation to the Commission regarding:

- Commission approval of the:
  - Sale of Electron Project to Electron Hydro;
  - Accounting and ratemaking treatment for the Electron Project sale;
  - Recovery of the remaining costs of the Electron Project in this rate year and future periods; and
- A prudence determination for the Electron PPA.

Q. Have you prepared any exhibits in support of your testimony?

A. Yes, I prepared Exhibit No. DCG-2C: Staff Adjusted PSE PCORC Supplemental vs. 2011 GRC Power Costs Comparison.

III. NOT-IN-MODEL POWER COST ISSUES

Q. What is the purpose of this section of your testimony?

A. In this section I discuss Staff's analysis of PSE's "Not-in-Model" power costs. Other than the Staff's use of a different rate year than PSE, Staff has no contested issues in this area.

Q **What is impact of PSE's total "Not-in-Model" power costs for the Company's rate year?**

A PSE includes $243.1 million of "Not-in-Model" power costs for the rate year, which is a reduction of $4.4 million from the Company's original filing.[6]

Q. **How does the level of "Not–in-Model" power cost above compare with 2011 GRC "Not-in-Model" power cost?**

A. Compared to the 2011 GRC, PSE's proposed "Not-in-Model" power costs for the rate year decreased by $43.8 million.

The most significant "Not-in-Model" power costs for PSE is transmission, which comprises 45 percent of the total "Not-in-Model" power costs for the rate year.[7] PSE's rate year transmission costs increased by $18.9 million compared to 2011 GRC levels. This increase is almost entirely due to an increase in BPA transmission cost as a result of BPA's 2014 rate case.[8] The Company's wind integration costs decreased from 2011 GRC levels by $2.2 million.

Q. **You earlier stated that you would address changes due to recent action by BPA. What is the current status of BPA's 2014 rate case?**

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[6] Mills, Exhibit No. DEM-7C.

[7] An annual total of [redacted] million; Mills Confidential Workpaper; *DEM-WP(C) Costs Not In AURORA 2013 PCORC Suppl.*

[8] According to Mr. Mills' Confidential Workpaper; *DEM-WP(C) Transmission 2013 PCORC Suppl.,* of the $18.9 million total increase for transmission, [redacted] million is attributed to the BPA rate increase. The remaining balance of [redacted] million of added power cost expense is split between an additional leg of 300 MW of point to point transmission required for the PG&E Exchange contract and a reduction in the interest credit related to Large Generator Interconnection Agreement (LGIA) between BPA and the Company for the Central Ferry Substation.

A. BPA has concluded the BP-14 rate proceeding to set power and transmission rates for the FY 2014-2015 rate period. On July 24, 2013, BPA released the Administrator's Final Record of Decision, July 2013, BP-14-A-03, in the 2014 Wholesale Power and Transmission Rate Adjustment Proceeding (BP-14), including Appendix A: Power Rate Schedules (BP-14-A-03-AP01-CC01) and Appendix B: Transmission, Ancillary and Control Area Service Rate Schedules (BP-14-A-03-AP02-CC01).

Q. How does the BPA decision in the 2014 rate case affect power costs in this case?

A. BPA's 2014 rate case decision will affect rate year power costs. For example, Staff understands that in its rebuttal case, the Company plans to reduce transmission power cost expense by another $3.1 million[9] to reflect BPA rates going into effect on October 1, 2013, that are lower than what PSE submitted to the Commission in its supplemental filing of June 7, 2013.

Q. Please explain your analysis of PSE's BPA transmission contract renewals and acquisitions.

A. I began my examination by first reviewing the Company's overall transmission capacity requirements for the rate year compared to forecasted load and peak demand months.[10] I found the Company's overall planned transmission capacity

[9] The Company estimated its rebuttal adjustment in an email correspondence to Staff from Kacee R. Chandler, Manager, Power Costs of August 1, 2013. Staff further confirms the $3.1 million estimate based on the Company's response to Industrial Customer of Northwest Utilities (ICNU) Data Request No.1.5 dated August 7, 2013. The rebuttal adjustment estimate would bring the total Transmission cost expense in power costs to [redacted] million for the rate year.

[10] Mills Confidential Workpaper; <u>*DEM-WP(C) Peaking Planner2013 PCORC.*</u>

requirements of 4,586 MW[11] to be reasonable. I also reviewed the testimony of Company witness Garratt in Exhibit No. RG-1CT regarding how PSE met the Commission's established standards for prudence for the BPA transmission contract renewals and acquisitions.

I conclude that PSE's decision to acquire and renew 1,875 MW[12] of BPA contracts is well supported by the evidence submitted by the Company and that the Company needs the transmission to serve customers in the rate year.[13] Staff recommends the Commission find that PSE acted prudently in its acquisition and renewal of the BPA contracts presented in this case.

Q. Please explain your analysis of PSE's wind integration costs and modeling for the rate year.

A. In the 2011 GRC, the Commission requested from PSE that future rate cases, "…present more detail concerning the historical data and modeling upon which the Company forecast of wind integration costs depend".[14] Within the scope of this requirement and consistent with the Commission's decisions regarding the recognition of wind integration costs, Staff is satisfied that the Company's proposed wind integration costs for the rate year are reasonable at $3.2 million.[15]

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[11] Mills Confidential Workpaper; DEM-WP(C) Transmission 2013 PCORC Suppl.
[12] DeBoer Exhibit No. TAD-1T, page 6, at 5 (Table 2). Note, that there are only 8 MW of added transmission and the majority of that amount represents renewals of contracts.
[13] *Utilities and Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08, ¶270, (May 7, 2012): "We expect PSE, for these reasons among others, to provide in its next rate case a more thoroughgoing body of evidence concerning the Company's method [for determining peaking resource costs]."
[14] *Utilities and Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08, ¶253, (May 7, 2012)
[15] Mills Confidential Workpaper; DEM-WP(C) Wind Integration Summary 2013 PCORC Suppl.: This amount is for integration costs separate from the $8.4 million in rate year transmission expense for the integration of

Particularly notable in this case is the Company's election of a newly available hourly scheduling option for the Variable Energy Resource Balancing Service (VERBS) that it receives from BPA, known as "Committed hourly scheduling" (30/60 scheduling).[16] This 30/60 scheduling option refers to how far ahead of delivery time the schedule value is established (30 minutes), and the second number refers to the duration of the schedule (60 minutes).

In its initial filing, PSE submitted VERBS expense numbers consistent with a selection of the Uncommitted scheduling option which would have given PSE the flexibility to schedule on an hourly or intra-hourly basis or a combination of hourly and intra-hour schedule periods, but at a higher cost.

The Company's supplemental filing of June 7, 2013, reduced VERBS costs by $1.6 million in the rate year to reflect the Company's 30/60 scheduling election.[17]

IV. AURORA MODEL POWER COST ISSUES

Q Is Staff recommending adjustments to the Company's proposed rate year AURORA Model power supply costs?

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wind projects within BPA's balancing authority. Mr. Rarity's Exhibit No. MDR-1CT, page 9, at 1-20 provides an itemized list of all proposed wind integration costs for the rate year which total $11.6 million.

[16] Administrator's Final Record of Decision, July 2013, BP-14-A-03, Section 1.2.3 discusses BPA's ongoing efforts to: "...address the challenge of balancing loads and resources to preserve system reliability while accommodating the rapid development of wind energy in the BPA balancing authority area." The hourly and inter-hourly scheduling options are part of BPA's overall efforts for: "...integrating wind generation in a manner that allows for the continued highly reliable operation of the Federal power and transmission system at the lowest cost consistent with sound business and operations practices."

[17] The Company's response to Commission Staff Data Request No. 58 provides additional detail around PSE's analysis of the costs and benefits associated with its selection of 30/60 committed scheduling for Hopkins Ridge and LSR Phase I over the other VERB committed scheduling options offered by BPA. The response also outlines the Company's ongoing commitment to evaluate its readiness and any net benefits to customers of moving toward 15 minute schedule durations in the future.

A. Yes. Staff proposes three adjustments related to the AURORA Model power supply costs. In one instance I estimate the actual effect of rate year power costs at the expense level, and for the remaining two I recommend that the Commission order PSE to include the effects of the adjustment as part of the Company's compliance filing.

Q. Please describe Staff's adjustments to AURORA Model power supply costs.

A. The first adjustment removes the cost of the 51,501 MW output of the Electron PPA and replaces it by the same amount of power at AURORA-modeled MID-C Flat prices. By my estimate, this adjustment would reduce AURORA Model rate year power costs by $1.4 million.

The second adjustment is due to Staff using a different rate year that PSE. Staff witness Mr. Mickelson is responsible for the rate year selection. I did not calculate the impact of this adjustment. I recommend the Commission order the Company re-run its AURORA model using updated inputs that reflect the appropriate rate year of December 1, 2013 through November 30, 2014. This should also include any necessary adjustments to "Not-in-Model" costs as well.

Finally, I recommend the Commission order the Company to carry out a "final" power cost update to reflect the latest available average gas price forecasts and any new fixed price power contracts for electric power and gas. As part of this update, the "Not-in-Models" Mark-to Market costs may also have to be updated. Staff is hoping that, at a minimum, the rate year timing issue could be reflected in the Company's rebuttal case, thereby giving Staff and other parties in this case sufficient time to review the data and results. The other items recommended above could be carried out as part of any final compliance filing by the Company, so long as all parties have adequate time to review the updates as proposed by the Company in Exhibit No. DEM-1CT, page 37, line 17.

A. Commission Approval of the Property Transfer and Staff's Electron PPA Adjustment

Q. Is PSE's sale of the Electron Project in the public interest?

A. Yes, if the sale is consummated according to the terms of the Asset Purchase Agreement (that is, under the conditions described below). The sale relieves PSE of any need to incur future retirement or reconditioning costs, which would be additions to PSE's current revenue requirement. Staff evaluated the options presented by PSE and found the chosen option of selling the plant as the best one. The other options have PSE maintaining ownership of the plant and either repairing the plant to a serviceable condition, or retiring and removing the plant altogether. Both of those options cause greater costs to rate payers.

Q What conditions should the Commission attach to its approval of the sale of the Electron Project?

A. While Staff recommends the Commission approve the sale of the Electron Project to Electron Hydro as in the public interest[18], the Commission's approval of the sale of

[18] In PSE's application in Docket UE-131099, the Company sought authority under WAC 480-143-180(1) to dispose of the Electron Project through a sale to Electron Hydro. Under that rule, the Commission would need to find the Electron Project no longer necessary or useful for PSE to perform its public duties. To make such a

the Electron Project is just one of a number of requirements that need to be satisfied before sale can close and Electron Hydro can deliver even a single MW of energy to PSE under the terms of the Electron PPA.[19] Given this fact, Staff recommends Commission approval be based on what the Company has presented regarding the sale in both its application in UE-131099 and this filing. Absent of these conditions, Staff is concerned that the terms of the Asset Purchase Agreement may be modified and result in an outcome that is not in the public interest. The Commission should approve the sale and transfer of the Electron Project to Electron Hydro under the following conditions:

- The Asset Purchase Agreement's Article 4, Section 4.2; Conditions to Closing, remains unchanged from what is filed in PSE's application in Docket UE-131099 and contained in Exhibit C to that application; and
- That there are no material changes to the consideration received or obligation incurred by either party as a result of the sale and transfer of the Electron Project as described in the Asset Purchase Agreement filed in in PSE's application in Docket UE-131099 and contained in Exhibit C to that application.

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finding, the Company must demonstrate to the Commission that the consideration received from the sale of the Electron project is of equal or greater value or usefulness than the Electron Project is worth. Central to that finding, as stated in the Company's application, is Electron Hydro's performance under the power purchase agreement with PSE. Given that uncertainties exist regarding when and how much power the Electron PPA will deliver, Staff cannot reliably evaluate that the "equal or greater value or usefulness" standard in rule has been met. Fortunately, the Company's application asks the Commission to allow the sale under WAC 480-143-120 as an alternative. That rule applies the public interest standard.

[19] A significant term of the Purchase and Sales Agreement is the need for approval of a Renewal Resource Agreement between the Puyallup Tribe of Indians and Electron Hydro.

Q. What are the uncertainties regarding the delivery of power from the Electron Project to PSE under the Electron PPA?

A. First, as described above, Electron Hydro and PSE have yet to close on the Asset Purchase Agreement, and therefore it is uncertain when the Electron PPA will be executed, when Electron Hydro will begin delivering power, and, if Electron Hydro does deliver power to PSE, how much power will Electron Hydro deliver to PSE in the rate year.

For example, under the Asset Purchase Agreement, Electron Hydro must negotiate and execute a Renewable Resource Agreement with the Puyallup Tribe of Indians (the Tribe). PSE also has to receive consent from the Tribe to terminate PSE's existing Renewable Resource Agreement with the Tribe.[20]

Furthermore, it is unknown how much power (if any at all) the Electron Project can produce in its current condition.[21] PSE has not provided a timeline for when Electron Hydro will take the Electron Project offline for necessary upgrades and reconditioning. These are substantial efforts, including a complete rebuild of the flume and penstocks, along with upgrades to the turbines.[22]

Q. What do these uncertainties mean for including the Electron PPA power costs in the AURORA Model?

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[20] Docket UE-131099, PSE Petition Exhibit C – Copies of all contracts related to the sale of the Electron Project, Asset Purchase Agreement, Article 4, Section 4.2.3.
[21] Wetherbee, Exhibit No. PKW-11C, page 9, Section 4.5 – Generation Outlook; "The historical trend of the plant production indicates that generation after 2012 without the flume box rebuild may not be feasible."
[22] Docket UE-131099, PSE Petition Exhibit C – Copies of all contracts related to the sale of the Electron Project, Power Purchase Agreement, Section 3.5 states that Electron Hydro intends to conduct its upgrades and improvements during the initial five (5) years of its operation of the Electron project and, as a result, may elect to limit the output of the project for periods of up to eight months.

A. These uncertainties mean that the Electron PPA costs and benefits are not known and measurable and therefore need to be excluded from rate year power costs as reflected in Staff's adjustment.

Q What other implications arise from the uncertainties surrounding the timing of the sale of the Electron Project?

A. Because it is unknown when the sale of the Electron Project will close, and on what terms, it is premature for the Commission to decide whether to unconditionally approve the accounting and ratemaking treatment proposed by the Company. PSE's proposal is to allow it to earn a return on and of the unrecovered costs and amortization expense of the Electron Project over a six-year period. While that may be acceptable if the project sale were consummated today, circumstances on the particulars of the accounting may dictate a different outcome in the future. Staff can accept the basic method proposed by PSE, but we suggest that the Commission reserve final approval for when the sale is finalized. For the same reasons, it is also premature for the Commission to conclude that the Electron PPA is prudent. Again, Staff could accept the terms and pricing of the Electron PPA as prudent today, but too many uncertainties exist to state our position for the future.

Q. Can the Commission approve the accounting and ratemaking treatment now, and have that treatment be effective once the sale transaction is closed?

A. In part, yes. The Company's proposed accounting and ratemaking treatment seeks recovery of a deferred balance of $10.8 million in remaining costs[23] of the Electron Project over a six year period.[24] This balance assumes a sale date of July 1, 2013. Given that the closing date of the sale is unknown (and unlikely to be known by the conclusion of this proceeding); it is premature to set rates based on today's deferred balance and the proposed recovery period.

For example, if the sale does not close until early 2014, then the remaining plant balance and expenses will be smaller; therefore, it may be more appropriate to amortize the balance over a shorter time period. As I have stated, Staff can accept the basic form of the proposed accounting treatment, but the specific details may require modifications once the contract is signed. It is appropriate to delay the approval of the ratemaking treatment for the benefit of both the Company and ratepayers.

Q. Has Staff prepared an exhibit showing each of Staff's proposed adjustments related to the Electron PPA and the Electron Project?

A. Yes. Staff witness Mickelson's Exhibit No. CTM-2 contains a series of adjustments associated with Staff's recommendation for the Electron Project. In addition to the $1.4 million power cost differential I discussed earlier in my testimony, the following adjustments are proposed by Staff:

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[23] The Company's proposal includes the Company earning a return on and of the deferral balance.
[24] Barnard, Exhibit No. KJB-1CT, page 28, at 10.

- Adjustment 1 - Operation and Maintenance Costs (O&M) for the Electron Project at half the test year amount - [redacted];[25]
- Adjustment 12 - Restores $18.6 million in net plant for the Electron Project and recognizes $4.9 million in depreciation expense for the rate year; and
- Adjustment 14 - Recognizes $59,890 in rate year property insurance for the Electron Project.

B. Adjustment for Rate Year Difference

Q. What AURORA Model power cost changes will be necessary to reflect the difference between Staff's rate year and PSE's rate year?

A. If the Commission accepts Staff's proposed rate year beginning December 1, 2013, the Company will need to update the timing of its natural gas price forecasts, the impact on any short-term electric power or fixed price gas supply contracts, the energy and/or other costs related to Company-owned generation, and the impact on the Mark-to Market adjustments. The updated rate year power costs will reflect the dispatch of PSE's system after any changes to inputs caused by the Staff's rate year starting one month later than PSE's proposed rate year.

[25] Company witness Wetherbee's Exhibit No. PKW-11C, page 6, Section 4.6, states that Energy Management Committee (EMC) approval of the sale and transfer would result in O&M costs being; "...cut in half due to reduced labor and material needs and the need for a capital expenditure program would be eliminated." Staff's adjustment reflects this statement.

Q. As you mentioned, Staff proposes a rate year starting one month later than PSE's proposed rate year. Can you calculate the AURORA Model power cost effects of the allowed gas price and short-term contract updates due to Staff's proposed timing shift?

A. No. I cannot determine the overall effect of the rate year difference and the update to gas and electric market prices, new contracts, and changes to 'Mark-to-Market" costs until they are actually carried out. However, as I noted earlier, given the relative stability of recent gas prices, I expect such changes to rate year power costs to be minimal.

C. Compliance filing

Q. What other power cost updates are you proposing to be allowed as part of any final compliance filing?

A. Consistent with past general rate cases, Staff is proposing that the Company be allowed to update those costs for which updates are "well-established" and "straightforward, mechanical, and non-controversial". As discussed in the Direct Testimony of David E. Mills, beginning on page 32, line 4, Exhibit No. DEM-1CT, this includes the effect on power supply of natural gas price forecasts and the resulting change to "Not-in-Model" Mark-to-Market costs.

The Company also correctly identifies new fixed-price short-term power and natural gas supply contracts as being items that are acceptable to update. Market prices for electric energy are automatically re-calculated as part of an AURORA dispatch model run. These items generally form the bulk of any power supply costs that have been allowed to be updated during a rate case proceeding. The Company has already filed supplemental testimony and exhibits reflecting adjustments to these items in June of this year during a period of an "uptick" in gas prices. However, the Commission should direct the Company to make a final update as part of any compliance filing in order to capture the entire effects of any decisions that are rendered regarding proposed power cost related adjustments.

The effect of this update should be included in the final revenue requirement determination of this PCORC proceeding.

Q. Does this conclude your testimony?

A. Yes.