EXHIBIT NO. _______ (JHS-10T)
DOCKET NO. UE-031725
2003 POWER COST ONLY RATE CASE
WITNESS: JOHN H. STORY

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	Docket No. UE-031725

REBUTTAL TESTIMONY OF
JOHN H. STORY
ON BEHALF OF PUGET SOUND ENERGY, INC.

FEBRUARY 13, 2004

PUGET SOUND ENERGY, INC.

REBUTTAL TESTIMONY OF JOHN H. STORY

Q: Are you the same John H. Story who submitted direct testimony in this proceeding on behalf of Puget Sound Energy, Inc. ("PSE" or "the Company")?

A: Yes, I am.

Q: What is the purpose of your rebuttal testimony?

A: In my rebuttal testimony, I will discuss the various adjustments to production ratebase, regulatory assets, and operating expense proposed by other parties.

Q: Please provide an overview of your rebuttal testimony.

A: In the first section, I will list the various adjustments to the Company's original filing proposed by other parties to which PSE will agree. **Ex. ___ (JHS-14)** demonstrates the revenue requirement impact of each adjustment to the Company's original filing that the Company agrees is appropriate. **Ex. ___ (JHS-13)** shows the resulting revenue increase of $54,481,144, which is an average 3.99 % increase for electric customers.

In the second section, I will list those adjustments to which PSE cannot agree. I also discuss how the Tenaska prudence disallowance has been applied consistently in each of the rate proceedings concerning power costs since the Commission issued its Nineteenth Supplemental Order in Docket UE-921262 in September 1994.

I. PSE AGREES THAT CERTAIN ADJUSTMENTS SHOULD BE MADE TO ITS ORIGINAL FILED REVENUE REQUIREMENT

Q: Have you prepared an exhibit which details the restating and pro forma adjustments that the Company is proposing?

A: Yes. **Ex. ____ (JHS-11)** summarizes the Company's restating and pro forma adjustments. This exhibit is presented in the same format as **Ex. ___ (JHS-4)** and Mr. Russell's **Ex. ___ (JMR-2)** and reflects the adjustments that the Company agrees are appropriate.

Q: Please describe Ex. ___ (JHS-11) in more detail.

A: In the column labeled "Test Year Actual 2003 TY" on the first page of the spreadsheet, the Company has made the same adjustments described by Mr. Russell for:

1) decreasing Regulatory Assets, reflecting the PCA settlement agreement in Docket No. UE-031389;
2) decreasing Production Rate Base, by removing Snoqualmie Falls relicensing costs because the FERC license will not be issued until later this year;
3) reducing Account 557, for property insurance; and
4) increasing property tax, to correct an error made in calculating the percentage associated with production plant.

The purpose of these adjustments is to reflect the appropriate amounts from the test period that should be considered in the Power Cost rate for the PCA. Only items 1 and 2 have an impact on the Company's original rate request as shown on **Ex. ___ (JHS-14)**. Items 3 and 4 are adjusted by other pro forma adjustments and do not impact the final revenue request. The total of this column agrees with the test year actual shown in Mr. Russell's Ex. ___ (JMR-2).

Q: Please describe the adjustments the Company has made to power costs in Ex. ___ (JHS-11).

A: Adjustment-1 pro forms the test year for rate year power costs. Mr. McIntosh raised several issues regarding the Company's presentation of power costs. These adjustments were to: (1) normalize maintenance schedules for Colstrip; (2) reduce winter peaking call expenses; and (3) complete a prudence disallowance with respect to production costs at March Point II and Tenaska. As Mr. Gaines and Ms. Ryan discuss in their rebuttal testimony, the Company has modified its Aurora model to take these first two concerns into consideration. *See* **Ex. __ (WAG-18T)** at 5-6**; Ex. __ (JMR-11T)** at 2-3. Rerunning Aurora for the normalization of the Colstrip maintenance, plus adjusting for March Point I availability which I discuss later, lowers power costs by $2.8 million. As explained by Ms. Ryan, reducing the amount and cost for winter peaking call options reduces power costs by $7.4 million. PSE also agrees that it had not applied the percentage disallowances for March Point II (3.0%) and Tenaska (1.2%) to its replacement power costs. *See* **Ex. __ (WAG-18T)** at 5. Making this correction decreases power costs by $392,000. This is different from Mr. McIntosh's adjustment of $576,000, as the Company's adjustment applies the disallowance on the average monthly secondary prices for replacement power whereas Mr. McIntosh's adjustment was based on average annual secondary prices. PSE discussed this difference and the calculations with Mr. McIntosh and he agrees with the Company's method.

Mr. Schoenbeck had also expressed concern with PSE's maintenance adjustment for Colstrip and the expected energy for March Point I. As discussed by Mr. Gaines in his rebuttal testimony, the Company has reviewed its calculation of the expected energy for March Point I and has adjusted its expected energy for this plant down by 51,678 MWh. *See* **Ex. __ (WAG-18T)** at 5.

PSE has also included in its adjustment to power costs an adjustment for major maintenance costs associated with combustion turbines that should not have been included in the original filing which reduces power costs by $1.3 million. The total of these adjustments and some minor adjustments to other plant costs associated with rerunning Aurora is to reduce test year power costs by $10.5 million from the power cost that PSE proposed in its original filing.

<u>Adjustment-2</u> pro forms the test year for rate year Sales for Resale. Due to the power cost changes made in the Aurora model, Sales for Resale is now a reduction of $152,198,362.

Q: Did the Company modify its estimate of natural gas prices from its original filing?

A: No. Since the PCORC is not designed to change methodologies used in the last general rate case for setting power costs, the Company does not propose a change in the method for setting natural gas costs. The Company uses the same forward pricing methodology that it used in the last general rate case (Docket No. UE-011570) to determine these costs.

As Mr. Schoenbeck discusses in his testimony, the PCA mechanism has sharing bands included in the calculation of deferrals, which allocate responsibility for power costs between customers and PSE. *See* Ex. ___ (DWS-1T) at __. With the sharing bands, a primary goal in setting the PCA baseline rate is to estimate the future power costs as closely as possible relative to the actual costs that will be experienced so that there is an equal chance of under- and over-recovery. If components of the baseline rate are set artificially lower than the projected actual costs, the Company will almost certainly under recover its costs. Mr. Schoenbeck's proposal would only increase the potential for cost under-recovery. If it is a concern that the projection of forward natural gas prices is too volatile or difficult to project, the most straightforward method to account for this volatility is to pass through the actual natural gas prices (much as what the Company does in its PGA filings). Mr. Gaines provides additional testimony as to why Mr. Schoenbeck's proposal to change the gas price methodology is not appropriate. *See* **Ex. __ (WAG-18T)** at 33-34.

Q: Please explain Adjustment-3 in Ex. ____ (JHS-11).

A: Adjustment-3 pro forms in the costs of Frederickson I plant into the test year. This adjustment is for the same amount shown in Mr. Russell's Ex. ___ (JMR-2). This rebuttal adjustment takes into consideration the removal of the sales tax from the purchase price of the interest in the Frederickson 1 project and the impact of that removal on accumulated depreciation, depreciation expense and deferred taxes. As Mr. Russell describes, the Company received a favorable ruling on its request that the Washington Department of Revenue verify that this transaction would not be subject to sales tax. *See* **Ex. __ (JHS-17)** . The Company's adjustment also corrects the accumulated depreciation to an average of the monthly average calculation rather than an end of period calculation as originally filed.

Q. Mr. Schoenbeck refers to PSE's Response to Staff DR. No. 2 to claim that the associated revenue requirement for Frederickson is only about 18.3 million. Is this correct?

A: That is the net change in revenue requirement for Frederickson. Without Frederickson in the revenue requirement the Company would have to replace its output with purchased market power. Mr. Russell's exhibit and my exhibit both show that the cost of Frederickson is approximately $42.4 million before revenue sensitive items. *See* Ex. ___ (JMR-2) and Adjustment-3 in my **Ex. __ (JHS-11)**.

Q: Please continue with your explanation of Ex. ____ (JHS-11).

A: Adjustment-4 restates transmission revenue. The Company agrees with the methodology proposed by Mr. Russell for determining the appropriate amount of transmission revenue to include for the rate year. Using Mr. Russell's three-year average for transmission revenue, this adjustment is the same as Commission Staff's proposal and reduces variable transmission income by $3,253,602.

Adjustment-5 restates depreciation expense and accumulated depreciation and reduces this expense by $65,231, which is the same amount shown on Mr. Russell's exhibit.

Adjustment-6 restates the property taxes for changes in property tax rates and production plant balances. The Company and Commission Staff adjustments are the same.

Adjustment-7 pro forms the rate year for the Montana energy tax on Colstrip generation. This adjustment reflects the change in the Colstrip maintenance schedule discussed earlier and increases other power expenses by $86,743, an increase of $34,937 from the original filing.

Adjustment-8 pro forms property insurance to current levels. The Company adjustment is the same as Mr. Russell's adjustment and increases other power expenses by $126,210.

Adjustment-9 pro forms White River to the rate year based on a tentative agreement with Commission Staff concerning the appropriate accounting treatment for this retired plant. This adjustment is for the same amount shown in Mr. Russell's Ex. ___ (JMR-2). When the Company originally filed its testimony in October 2003, it was not sure whether White River would be retired or whether PSE would receive an extension of the stay of the pending FERC license (which was then scheduled to expire on January 15, 2004). *See* **Ex. __ (WAG-1T)** at 25-26. Accordingly, the Company removed the plant from its power costs and substituted market cost power to replace this facility's output. Subsequent to its PCORC filing, PSE determined that it would no longer seek a FERC license for the White River Project or an extension of the stay of the license. Consequently, the plant ceased commercial operation on January 15, 2004.

As Mr. Russell describes, the Company has filed an Accounting Petition with the Commission requesting that the Company be allowed to defer the plant costs as a regulatory asset and to continue amortizing these costs at the current depreciation rate until better information is known related to sales and salvage values associated with this property. Commission Staff agrees with this accounting, which is similar to the retirement of mass utility property; when such utility property is retired, its book value less any salvage is debited to accumulated depreciation and in effect remains in rate base. Depreciation rates are adjusted in future depreciation studies to reflect the impacts of these retirements. The difference between White River and other mass utility property, however, is that there is no PSE property similar to White River remaining in plant to depreciate and adjust future depreciation expense to reflect the retirement. This regulatory asset will be adjusted by any Commission-approved costs and receipts associated with salvage or possible sales associated with the water rights.

This adjustment is the same as shown in Mr. Russell's exhibit.

Adjustment-10 pro forms the rate year rate for the regulatory assets associated with Tenaska, Cabot, Bonneville Exchange Power and Encogen Acquisition Adjustment. The Company has made the same adjustments discussed by Mr. Russell for Tenaska and Cabot based on the PCA Compliance Settlement in Docket No. UE-031389. We have also revised the Encogen Acquisition Adjustment to the test year level. This adjustment decreases regulatory asset expense by $3,521,669 which agrees with Mr. Russell's exhibit.

Adjustment-11 pro forms the test year using the production adjustment to adjust production rate base and production operating expenses that have not been adjusted in the power cost, sales for resale, transmission income or new plant adjustments. As set forth in the Stipulation Between Puget Sound Energy and WUTC Staff Regarding Weather Normalization Adjustment, filed on February 10, 2004, for purposes of this PCORC proceeding only, the Company has agreed to use Commission Staff's weather normalization adjustment for test year load to determine the production adjustment. This changes the production factor to .899% and the adjustment decreases expense by $1,353,716. This change in production factor has also been reflected in Adjustment 1, 2, 3 and 4 of this exhibit.

Q: Please describe Ex. ___ (JHS-12).

A: **Ex. ___ (JHS-12)** updates **Ex. ___ (JHS-5)** to reflect the changes to production ratebase and operating expenses discussed earlier. This exhibit also updates the current PCA Settlement exhibits accepted in Docket No. UE-011570. These pages need to be approved by the Commission, with the updates approved in this Docket, so that they can be used in calculating the PCA deferrals once the new PCA rate is approved. The Company has included Exhibit E as proposed by Mr. Russell. I would like to point out that, in addition to the explanation of changes presented by Mr. Russell for this exhibit, his exhibit also splits the Spokane MSW rate between winter and summer rates pursuant to the settlement of the PCA Compliance filing.

Q: Please explain the calculation shown in Ex. ___ (JHS-13).

A: **Ex. ___ (JHS-13)** calculates the revenue deficiency for the test period by calculating the difference between the baseline power costs for test year and the original baseline power costs adopted in Docket UE-011570. This difference is then multiplied times the test year normalized load to determine the baseline rate increase. For purposes of this PCORC proceeding only, the Company has agreed to use the Commission Staff's adjustment for temperature normalized test year load to determine the Power Cost Rate. The Power Cost Rate increase is then adjusted for revenue system items to determine the PCORC increase.

As explained in Mr. Russell's testimony, the components of the revenue-sensitive items have decreased since the original PCA settlement rate was determined. *See* Ex. ___ (JMR-1T) at 17 beginning at line 9. As he also explained, and unlike other items in the PCA rate calculation that had been discussed and agreed upon as to whether they would be adjusted in a PCORC filing, the revenue-sensitive items had not been discussed. He proposes that the revenue-sensitive items rate be adjusted for the revenues that are currently built into the PCA rate and not just the incremental revenue increase determined in this PCORC proceeding. The Company is agreeable to this type of ongoing adjustment for revenue sensitive items. As shown on **Ex. ___ (JHS-14)**, this decreases the revenue requirement by $227,530, resulting in a total rate increase is $54,481,144.

Q: Please explain your Exs. ____ (JHS-15) and **____ (JHS-16)**.

A: **Ex. ____ (JHS-15)** is the allocation of the PCORC revenue requirement. This calculation is based on the peak credit methodology used in Docket No. UE-011570. Column g shows the revenues deficiency allocated to each customer class and column i shows the change in Schedule 95.

Ex. ____ (JHS-16) shows the Statement of Pro forma and Proposed Revenues. Column e of this exhibit shows the dollar increase by Schedule associated with this revenue change and Column f shows the percentage increase by Schedule.

II. PSE CANNOT AGREE TO CERTAIN ADJUSTMENTS TO ITS ORIGINAL FILED REVENUE REQUIREMENT

Q: Are there proposed adjustments with which PSE cannot agree?

A: Yes. PSE cannot agree with the proposed adjustments relating to the fuel costs associated with the Tenaska and Encogen projects. Mr. Gaines and Ms. Ryan discuss in their rebuttal testimony why these adjustments are inappropriate. *See* **Ex. __ (WAG-18T)** at 6-29; **Ex. __ (JMR-11T)** at 3-11.

Q: What would be the impact on the Company if the Tenaska and Encogen adjustments proposed by other parties are accepted by the Commission?

A: Mr. Schoenbeck's recommended approach is to write-off the regulatory asset associated with Tenaska. Obviously this would create a $213 million dollar write-off which would basically eliminate the Company's earnings for a year. It should be noted that even though the write-off would be reflected for financial purposes the Company would not be able to take a current tax deduction for this item. The impact on the Company's credit rating would obviously be negative and its ability to trade in the wholesale markets could be severely impacted.

Commission Staff's and Public Counsel's proposals both involve adjusting the deferred power cost balance associated with the first PCA period, July 2002 through June 2003. Any adjustments to this balance would be recognized in expense in 2004 and would have a 1 cent impact on earnings per share for every $1.5 million disallowance. In addition, both of these parties propose adjustments to the recovery of allowable costs for the regulatory assets associated with the gas contract restructures.

The impact of these regulatory asset adjustments is difficult to quantify, but it is likely the credit rating and earnings of the Company would also be adversely impacted.

(These proposals are difficult to quantify because Financial Accounting Standards Board (FASB) Statement No. 71 ("Accounting for the Effects of Certain Types of Regulation" as modified by FASB Statement No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets") requires that there be a reasonable assurance of the existence of an asset for a utility to be able to record the asset. Recording of the asset requires (1) probable future revenue in an amount at least equal to the capitalized cost will be recovered in rates and (2) future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the incurred cost no longer meets these two criteria, the cost has to be charged to expense.)

Q: Are you familiar with the Commission's disallowance of Tenaska contract charges in its Nineteenth Supplemental Order in Docket No. UE-921262?

A: Yes. During that proceeding I was the accounting witness for Puget Sound Power & Light Company ("Puget").

Q: Are you familiar with the filings made under the Periodic Rate Adjustment Mechanism ("PRAM")?

A: Yes. I was Puget's accounting witness for each of the PRAM filings.

Q: How were the Tenaska and March Point II prudence disallowances handled in the PRAM proceedings?

A: The actual costs paid to Tenaska, plus replacement power for displacement, were adjusted downward by 1.2% and the same type of costs associated with March Point II were adjusted downward by 3% based on the Commissions 19th and 20th Supplemental Orders in Docket No. UE-921262 for PRAM 4 and 5. PRAM 3 was adjusted by a disallowance of $1 million from the revenues that were collected subject to refund.

Q: Are you familiar with the rates set in the Merger Rate Plan period?

A: Yes. I was the accounting witness for the Joint Appplicants, Puget and Washington Energy Company.

Q: Did the rates approved by the Commission in the Merger Rate Plan period take into consideration the Tenaska disallowance?

A: Yes. Appendix A of the Fourteenth Supplemental Order Accepting Stipulation; Approving Merger in Dockets No. UE-951270 and UE-960195 is the Stipulation the parties to the filing entered in to resolve the disputes associated with that Docket. Paragraph 3.c of the Stipulation states the revenue requirement for PSE's electric retail rates is based on the PRAM 5 proceeding. PRAM 5 power costs were calculated with the disallowance for March Point II and Tenaska applied.

Q: Were you involved in PSE's 2001 General Rate Case?

A: Yes. I was a member of the Company's team negotiating the settlement of the General Rate Case. The settlement did include the percentage disallowances as applied to Tenaska and March Point II.

Q: Did the Commission's orders in any of these proceedings ever discuss a cap associated with these resources?

A: No. These resources were always adjusted by the percentages discussed in the Commission's orders in Docket UE-921262 and by a flat $1.0 million for PRAM 3.

Q: Did Commission Staff or any other party ever inform the Company that they believed there was a cap associated with these resources?

A: No, not to my knowledge.

Q: Has the Company made any adjustments to its revenue requirement based on the other parties' assertions that there was a cap imposed on Tenaska and Encogen in Docket UE-921262?

A: No. Mr. Gaines discusses in his rebuttal testimony why any such adjustments are inappropriate. *See* **Ex. ___ (WAG-18T)** at 6-29.

Q: Are you sponsoring any rebuttal exhibits?

A: I am sponsoring the following rebuttal exhibits:

EXHIBIT LIST

	Description of Exhibit	Exhibit Number
JHS-10T	Rebuttal Testimony of John H. Story	
JHS-11	Company's Test Year and Restated/Proforma Power Cost Rate with accompanying Adjustments	
JHS-12	Power Cost Rate used to calculate PCA deferrals and updates to PCA Settlement exhibits accepted in Docket No. UE-011570	
JHS-13	PCORC Revenue Deficiency	
JHS-14	Explanation of Differences in the Revenue Deficiency Calculated in JHS-6 (Original Filing) and JHS-13 (Rebuttal Testimony)	
JHS-15	Allocation of PCORC Revenue Requirement	
JHS-16	Statement of Proforma and Proposed Revenues	
JHS-17	Washington Department of Revenue Letter	

Q: Does this conclude your rebuttal testimony?

A: Yes, it does.