EXHIBIT NO. _____ (JHS-1T)
DOCKET NO._____
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. _____

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

OCTOBER 24, 2003

TABLE OF CONTENTS

PUGET SOUND ENERGY, INC.

DIRECT TESTIMONY OF JOHN H. STORY

Q: Please state your name, business address and occupation.

A: My name is John H. Story and I am Director of Cost and Regulation with Puget Sound Energy, Inc. (PSE). My business address is 10885 NE 4th Street, Bellevue, Washington, 98009-5591.

Q: What are your responsibilities in your current position?

A: As Director of Cost and Regulation, I am responsible for the Revenue Requirement and Pricing & Cost of Service departments at PSE.

Q: Please describe your educational background and work experience.

A: I graduated from the University of Washington in June of 1973 with a Bachelor of Arts degree in Business Administration, and a major in Accounting. My work experience is described in more detail in **Ex. ____ (JHS-2)**.

I. SUMMARY OF TESTIMONY

Q: Please summarize your testimony in this proceeding.

A: My testimony describes: (1) adjustments to PSE's power supply costs that have prompted PSE to seek the proposed Power Cost Rate; (2) the rate impact of adding a new resource to PSE's power supply portfolio; (3) the calculation of PSE's new Power Cost Rate, which accounts for the addition of new power cost resources to PSE's power supply portfolio, updates expenses to account for current costs and corrects the allocation for production related costs;; and (4) the change to customer tariffs attributable to the adjustments to the Power Cost Rate. The total rate increase resulting from these changes is $64,443,049, an average 4.72% increase over the rates set in July 2001.

II. ADJUSTMENTS TO THE POWER COST RATE

Q: Please define the term Power Cost Rate.

A: In PSE's most recent general rate case, Docket Nos. UE-011570 and UG-011571, the Commission approved the parties' Settlement Stipulation for Electric and Common Issues ("Settlement Stipulation"). *See* Commission's Twelfth Supplemental Order (dated June 20, 2002) ("Twelfth Supplemental Order"). Among other things, the Twelfth Supplemental Order authorized the use of a Power Cost Adjustment Mechanism (PCA) as a method for adjusting PSE's power costs. *See Settlement Terms for the Power Cost Adjustment Mechanism, Exhibit A to the Settlement Stipulation* attached to the Testimony of William A. Gaines as **Ex. ____ (WAG-7).**

As described in Mr. Gaines's testimony, the PCA sets forth an annual accounting process for a sharing of costs and benefits between PSE and its customers over four graduated levels (so-called "bands") of power cost variances, with an overall cap of $40 million (+/-) over the four year period July 1, 2002 through June 30, 2006. *See* **Ex. ____ (WAG-1T)** at 16; **Ex. ____ (WAG-7)** at 1. The PCA distinguishes between power costs and all other costs included in general rates and allows PSE to file an application seeking adjustment of only PSE's power costs. *See* **Ex. ____ (WAG-7)** at 2. The PCA included a table that showed the allocation of costs between costs that can be adjusted through the Power Cost Rate, and non-power costs, which cannot be adjusted through the PCA. Two categories of cost comprise the Power Cost Rate: variable rate components and fixed rate components. That table is provided as **Ex. ____ (JHS-3).**

Q: When are the accumulated PCA costs and benefits allocations accounted for?

A: In August of each year, PSE files an annual report detailing the power costs included in the deferral calculation for the period ending June 30 of each year. *See* **Ex. ____**

(WAG-7) at 2; *and see generally* PSE's Annual PCA Report, Docket No. UE-031389 (filed August 28, 2003).

Q: How is the Power Cost Rate adjusted?

A: Independent of the yearly accounting and adjustment for power cost variances, PSE may also apply to the Commission to true up the Power Cost Rate to all power costs identified in the Power Cost Rate. Mr. Gaines explains the filing requirements and review timing of such a Power Cost Only Rate review process. *See* **Ex. ____ (WAG-1T)** at 16-17. Specifically, the PCA Settlement Stipulation requires, among other things, testimony and exhibits that include

- Adjustments to the Fixed Rate Component
- Adjustments to the Variable Rate Component
- A calculation of pro forma production cost schedules that are consistent with this docket, including power supply and other adjustments impacting then current production costs.

See **Ex. ____ (WAG-7)**, at 5. My testimony provides this required information in support of PSE's present application to true up its Power Cost Rate.

Q: Would you please describe the adjustments used to determine the new Power Cost Rate?

A: As stated earlier, the PCA makes a distinction between power cost only costs and all the other costs determined in a general rate case. In 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. Using this methodology for the present case, I have summarized the power cost adjustments, plus restating adjustments, associated with production costs in the attached **Ex. ____ (JHS-4).** The proposed rate year used for these adjustments is April 2004 through March 2005. For this proceeding we used the test year June ended 2003.

In addition to the above general rate case adjustments, we have provided a pro forma adjustment to account for changes to PSE's ratebase and operating expenses associated with the purchase of Frederickson 1.

Q: Please explain what Ex. ____ (JHS-4) represents.

A: The first column of **Ex. ____ (JHS-4)** is the ratebase and production costs from the test year that are considered in setting the Power Cost Rate. The first column, entitled "Test Year Actual 2003", sets forth the ratebase and actual production costs for the test year ended June 2003. The columns to the right of this column show the impact of the pro forma and restating power cost adjustments PSE is proposing for the pro forma rate year. These adjustments are presented in more detail on the succeeding pages referenced in the title of a particular column and the work papers supporting the adjustments have been provided to Commission Staff and intervenors. The total of the test year amounts plus the pro forma and restating adjustments is shown in the column titled Total Adjustments for Rate Change. This final column represents the costs to be used in determining the Power Cost Rate used to calculate the required rate increase. These are the same amounts shown in the first column of **Ex. ____ (JHS-5C).**

A. Non-Acquisition Power Cost Adjustments

Q: Please describe each of the adjustments presented in Ex. ____ (JHS-4).

A: The adjustments are:

1) Power Cost - **ADJUSTMENT-1** presents the rate year pro forma power costs discussed by Mr. Gaines and presented in **Ex. ____ (WAG-15).** These costs are the rate year variable and fixed power operating and maintenance costs adjusted to test year levels using the relationship of normalized test year delivered load to rate year delivered load (production factor). These projected costs are compared to the

equivalent test year costs and the difference is used to adjust the test year costs on the first page of **Ex. ____ (JHS-4)**. The decrease in cost is $145,707,474.

2) Sales for Resale – **ADJUSTMENT-2** pro forms the rate year secondary sales presented in **Ex. ____ (WAG-15)** to test year secondary sales. This is a reduction in secondary sales of $152,598,327.

3) Frederickson 1 – **ADJUSTMENT-3** pro forms the cost of Frederickson 1 for both rate base and operating expenses. The assumptions for the costs used in this adjustment are explained later in my testimony.

4) Transmission Income – **ADJUSTMENT-4** pro forms the forecast transmission income for the four transmission lines identified in the power cost rate to the expected rate year levels. The rate year revenues reflect the continuing trend of lower market demand for wheeling on these lines. This adjustment reduces transmission revenue by $5,593,730.

5) Depreciation and amortization – **ADJUSTMENT-5** restates the depreciation expense and accumulated depreciation to an average of the monthly averages calculation by reducing expense by $65,231.

6) Property taxes – **ADJUSTMENT-6** restates test year property taxes for known changes in the levy rates and production plant balances for Montana, Oregon and Washington by increasing expense $652,699.

7) Montana Energy Tax – **ADJUSTMENT-7** pro forms the tax that is assessed on Colstrip generation. This adjustment compares the forecast generation of the Colstrip

plants to the actual generation in the test period and the difference is priced at the appropriate tax rate and increases expense by $51,806.

8) Property insurance – **ADJUSTMENT-8** restates production property insurance to current levels and it reduces expense by $349,649.

9) White River – **ADJUSTMENT-9** restates rate base for the removal of the White River generation plant and facilities. The reduction of operating expenses are reflected in **Ex. ____ (WAG-15)** and are included in **ADJUSTMENT-1**. The Company is currently operating White River under a hydro license extension granted by FERC that expires January 15, 2004 as explained by Mr. Gaines. *See* **Ex. ____ (WAG-1T)** at 25-26. This adjustment reduces revenue requirement by $6,752,621.

10) Regulatory Assets – **ADJUSTMENT-10** pro forms the rate year rate base and amortization for the regulatory assets associated with Tenaska, Cabot, and BEP contract buyouts. This adjustment reduces expense by $3,916,258.

11) Production Adjustment – **ADJUSTMENT-11** pro forms the production related rate base and expenses which have not been included in the power cost adjustments. As with the Power Cost Adjustment, these costs are adjusted to test year levels using the relationship of normalized test year delivered load to rate year delivered load (production factor) so that the test year level of costs are collected in the rate year. This adjustment reduces expense by $1,562,398.

Q: Please explain the last two pages of Exhibit ____ (JHS-4).

A: The second to last page of the exhibit presents the adjustment changing test year load to a temperature adjusted load. As the year was warmer than normal, on average, this adjustment adds MWHs to the actual load. This adjustment is required to determine

normal delivered load in the test year for the production adjustment and normal billed load for the rate spread.

The last page is the conversion factor for revenue sensitive items. This calculation uses the bad debt percentage from the last General Rate Case and the current Annual Filing Fee and State Utility Tax rates. This factor is used in determining the revenue increase as shown on **Ex. ____ (JHS-6),** line 18.

Q: Please describe how the test year delivered load was normalized.

A: Test year Generated, Purchased and Interchange (GPI) load of 20,512,959 MWH were temperature normalized using a technique that is comparable to that used by many utilities. The temperature normalization process requires that an estimated relationship (coefficients) between daily customer load and observed temperatures be calculated. Heating degree days (HDD) and cooling degree days (HDD) are used to reflect this temperature sensitive portion of load. It is necessary to have separate temperature (or HDD and CDD) estimated coefficients for each month because of changing temperature - load relationships during the year. With these estimated coefficients, temperature normalized load can be approximated by multiplying the coefficients by normal temperatures (in this case the thirty year average temperature 1973-2002). The result is temperature normalized load for the test year which can be compared to actual test year load to determine the test year temperature load adjustment. In this case the test year temperature load adjustment is 85,568 MWH, or 80,018 MWH delivered load when adjusted for losses.

B. Power Cost Adjustments Attributable To Acquisition

Q: Please describe each of the components presented in Ex. ____(JHS-4) that are attributable to PSE's acquisition of and ownership interest in the Frederickson 1 generating facility.

A: **ADJUSTMENT-3** presents the rate base and operating expenses associated with Frederickson 1 for the rate year. The plant balance, shown on line 2 of this schedule, is the sum of the actual purchase price for Frederickson 1, $76,321,070 and capitalized transaction costs of $3,506,162. This total is adjusted for sales tax of 8.2% which is an additional $6,258,328. The source for the figures in this column are Eric Markell's testimony, **Ex. ____ (EMM-43C).**

Q: Please explain what type of expenses are included in the capitalized transaction costs.

A: The capitalized transaction costs consist of the directly related incremental expenses PSE incurred for engineering studies, legal assistance, and financial consulting associated with the purchase of Frederickson 1. PSE capitalized these costs in the financial quarter that the decision was made to pursue the purchase of Frederickson 1 and include an estimate for the period until the contracts are finalized in the fourth quarter of 2003. As some of these costs are estimated they will be adjusted to actual during this proceeding.

Q: Why has the Company included sales tax in its calculation of the purchase price?

A: This purchase could be taxable under RCW 82.08. We are in the process of requesting a waiver from the Washington State Department of Revenue for the application of this tax under WAC 458-20-106. This WAC provision allows for a tax exemption if the petitioner is buying into a partnership that includes assets that have had sales or use tax applied. If PSE receives a positive response to its request for exemption then the acquisition price would be reduced by the amount of this tax.

Q: When does the Company expect to receive a ruling on this request?

A: The timing of the ruling is dependent on the Washington State Department of Revenue. We feel this ruling should be received during the course of this proceeding and the appropriate adjustment would be made at that time. If the ruling is received after the close of this Docket, the Commission should include in its Order a provision that this item will be trued up to actual cost based on the Department of Revenue ruling.

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

A: We have assumed that this purchase will be finalized upon receipt of a favorable Commission Order, which the Company is requesting be issued prior to the end of March 2004. Using the end of March as the purchase month we calculated the average of the monthly averages balance for the rate period.

For book depreciation purposes we are proposing that the asset be depreciated over 30 years which is a 3.33% depreciation rate. For the year 2004 we assumed 9 months of depreciation and we added 3 months of depreciation for the year 2005. The resulting monthly accumulated depreciation was then averaged in the same manner as the acquisition cost.

Deferred taxes were calculated in the manner prescribed by Internal Revenue Code Regulations, Section 1.167(l)-1(h) . This Section specifies the methodology of how a future projection of an asset must be treated for the normalization method of accounting. The methodology as described presents a calculation that allows deferred taxes to be deducted for ratemaking purposes if calculated based on the pro rata number of days the future period plant is considered for inclusion in rate base.

The acquisition price less the accumulated depreciation and deferred taxes for the April through March 2005 time period is the amount that we used to calculate the return

needed to cover the capital costs for Frederickson 1. As allowed in the PCA mechanism we used the net of tax rate of return to calculate the allowed return and divided this return by the reciprocal of the effective federal tax rate to get an allowed return of $9,315,380 shown on line 7 of **ADJUSTMENT-3.**

Q: Please explain the other costs associated with Frederickson 1.

A: Depreciation expense shown on line 9 was explained earlier. The plant property insurance and property taxes were presented by Mr. Markell and are PSE's share of these expenses.

Natural gas, wheeling and secondary sales are included with the power costs discussed by Mr. Gaines and are in **Ex. ____ (WAG-15)**. Variable production operating and maintenance expenses were provided by Mr. Markell and are calculated for the rate period using a $2.65 variable rate per MWH during months in 2004 and $2.655 / MWH during months in 2005. These rates were determined by summing the Company's share of the total variable operation and maintenance costs as forecast by the present Project Owner/Seller (EPCOR) and dividing by the Company's share of energy produced from 249.5 MW of capacity operating at a 100% capacity factor. These rates were then applied to the rate year MWHs for the plant.

The total of all these costs is $43,061,670 as shown on line 22 of **ADJUSTMENT-3.**

III. POWER COST RATE

Q: Please describe the impact of the pro forma adjustments on the Power Cost Rate.

A: **Ex. ____ (JHS-5C)** shows the impact of the above adjustments on the Power Cost Rate. This exhibit is prepared in the same manner as Exhibit A included in the PCA Mechanism. *See* **Ex. ____ (WAG-7)** at Exhibit A-1. The costs have been allocated in the same manner between fixed and variable costs and the total costs are adjusted for

revenue sensitive items. Following the same methodology set forth in Exhibit A in the PCA, this result is then divided by the test year load to calculate the new Power Cost Rate of $47.154 per MWH. This is the rate that is used for determining the required revenue increase in **Ex. ____ (JHS-6)**.

Q: Please explain the column labeled Cleanup Adjustments to Power Cost Rate in Ex. ____ (JHS-5).

A: During the process of preparing this filing, we found several production related ratebase and expense items that were not properly classified as production in the last general rate case. This column includes the impact of these items on the Power Cost Rate, but they do not have any impact on the requested rate increase. The resulting Power Cost Rate of 47.306 per MWH is the new rate that the Company proposes for calculating the future power cost recovery upon approval by the Commission.

Q: Please explain each of these adjustments.

A: On line 13, the $.08 adjustment adds the return on non-depreciable property associated with production plant to the Power Cost Rate. This asset had not been included in the original Power Cost Rate. The amount of $.041 added on line 14 is the return on transmission facilities at Colstrip. This transmission plant is part of the regulatory asset associated with Colstrip common plant and should be included as this line is tracked in the Power Cost Rate. The $.018 and $.013 on line 25 and 26 are the associated amortization and depreciation associated with the first two adjustments.

Q: Please explain the remaining pages included in Exhibit ____ (JHS-5).

A: The remaining pages of this exhibit are equivalent to the exhibits A-2 through E included in the PCA Settlement and have been updated to reflect the changes in power costs presented by the Company. In the upper left hand corner of each of these pages is the reference to the exhibit being replaced in the Power Cost Adjustment Mechanism.

Q: How will the new Power Cost Rate be implemented as the proposed rate year does not match the normal PCA period of July through June?

A: Each month the Company calculates the potential over or under collection of power costs for the PCA. For the fixed cost component of the PCA we assume that these costs are collected equally over the twelve month period. Once we have the new rate approved we will change this part of the calculation to reflect the new monthly fixed costs allowed in the PCA for the remaining months of the PCA period.

As the variable costs are adjusted to actual variable costs we will treat these costs in the same manner as the current PCA calculation. We will then deduct for any adjustments required under the PCA mechanism, including, for example, the Schedule E Contract Adjustments. Exhibit E for the second PCA period will be divided into two rate periods: one 9-month period limited to current PCA contract rates, the other 3-month period limited to the new PCA contract rates.

In addition, the new PCA contract rates for Schedule E has been corrected to segregate the contract rate limit for the Spokane Solid Waste Management System to Summer and Winter seasonal rates to correspond with the contract. It is requested that the Commission approve this split in the contract rate be effective with the start of the second PCA period, July 2003, so that this contract can be calculated properly for the change in PCA rate.

The monthly total of the above adjustments will then be compared to an individual month's kWhs multiplied by the new Power Cost Rate and this variance will be the amount that will be considered in the sharing mechanism of the PCA.

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

IV. RATE INCREASE

Q: Please explain how the Company calculated the rate increase required after taking into consideration the pro forma and restating adjustments.

A: As the Company is only requesting that a portion of its rates be adjusted using the Power Cost only rate filing, we have calculated the required change in rates using the difference between the current Power Cost Rate and the proposed rate before the Adjustments for Power Cost Rate. This calculation is shown in **Ex. ____ (JHS-6)**. As shown on line 15 of this exhibit, the new rate is $47.154 and the current rate is $43.953. The difference between these two rates is multiplied by the normalized delivered load for the test period. The result of this calculation is the requested change in revenue requirement of $64,443,049 after revenue sensitive items. This change in rates results in an average increase of approximately 4.72%.

Q: Is the Company proposing to file for any power cost deferrals with this change in revenue requirement?

A: No. At this time the Company projections do not show the deferral balance will exceed the $30 million dollar limit which would allow the Company to request recovery.

V. RATE DESIGN

Q: Please summarize how the proposed change to the Power Cost Rate will be charged to customers.

A: The PCA requires that changes in rates attributable to adjustments to the Power Cost Rate as a result of power cost only review be charged to customers based upon the peak

credit methodology utilized in computing the rate spread methodology in Docket No. UE-011570. *See* **Ex. ____ (WAG-7)** at 7. The proposed deficiency presented in this case is due entirely to a power cost only review. Accordingly, we have applied the peak credit methodology to the total deficiency in Power Costs shown on **Ex. ____ (JHS-6)** at line 19. This determines the amount of the power cost deficiency to be recovered from each rate schedule. This rate schedule power cost deficiency will then be charged to customers on a cents/kWh basis for each schedule using test year pro forma volumes.

Q: Please describe the peak credit methodology utilized in the rate spread methodology in Docket No. UE-011570.

A: The peak credit methodology classifies historic test year production costs between demand and energy according to the current demand/energy relationships. Further, the peak credit methodology calls for the demand-related portion of the now-classified production costs to be allocated or assigned to classes or schedules based on their contribution to the top 200 hours of system peak load. The energy-related portion of these costs is to be allocated to schedules based on the schedule's share of total annual kWh consumption for the test period. In Docket No. UE-011570, the peak credit methodology used in the rate spread methodology resulted in peak credit classification factors of 16% and 84% for demand and energy, respectively.

These peak credit classification factors are then used to weight each schedule's total demand during the top 200 hours of system demand and total annual kWh consumption. This provides the peak credit weighted allocation factors for each schedule.

Q: Please describe Exhibit ____ (JHS- 8), entitled "Allocation of Power Cost Deficiency."

A: **Ex. ____ (JHS-7)** presents the allocation of the proposed power cost deficiency to applicable schedules using the peak credit weighted allocation factors. A description of each of these columns is included as the last page of the exhibit.

Q: Please describe Exhibit ____ (JHS-9), entitled "Statement of Pro forma and Proposed Revenue."

A: **Ex. ____ (JHS-9)** shows the pro forma and proposed revenue under current and proposed rates based on test period sales volumes and billing determinants. On this exhibit, Column (a) represents the test year pro forma sales volumes for each schedule; Column (b) shows total test year pro forma revenue produced at current rates; and Column (c) shows the cents/kWh attributable to adjustments to the Power Cost Rate to be charged to customers on each of the applicable schedules. Total revenue under the proposed rates is shown in Column (d), and the total increase in revenue due to the proposed change in the Power Cost Rate is shown in Column (e). The percentage impact of the proposed change on each of the applicable schedules is shown in Column (f).

Q: Has the test year proforma billed load in Ex. ____ (JHS-8) been adjusted for the 80,018 MWH temperature adjustment presented on Ex. ____ (JHS-4)?

A: Yes, the test year pro forma billed load shown on **Ex. ____ (JHS-8)** has been adjusted for the 80,018 MWH temperature adjustment presented on **Ex. ____ (JHS-4)**. Since delivered load in **Ex. ____ (JHS-4)** was normalized on a per customer basis, the resulting temperature 80,018 MWH temperature adjustment was allocated to each of the applicable schedules by month based on each schedule's pro rata share of total customers. For purposes of this allocation, Lighting and High Voltage schedules were

excluded as it is felt these schedules would require little or no adjustment for temperature.

Q: Has the Company prepared a revised Schedule 95 Power Cost Adjustment Clause to reflect the proposed adjustments to the Power Cost Rate?

A: Yes, a revised Schedule 95 Power Cost Adjustment Clause is presented in **Ex. ____ (JHS-9)**. The revised Schedule 95 Power Cost Adjustment Clause reflects the amount to be charged to customers on each of the applicable schedules as calculated in **Ex. ____ (JHS-7).**

Q: Are you sponsoring any exhibits in this proceeding?

A: Yes. I am sponsoring the following exhibits, which are attached to my testimony:

EXHIBIT LIST

	Description of Exhibit	Exhibit Number
JHS-1T	Testimony of John H. Story	
JHS-2	Description of John H. Story's responsibilities, current position, and educational background	
JHS-3	Total Revenue Requirement Table (PCA Cost/Rate Designations)	
JHS-4	Power Cost Adjustments	
JHS-5	Power Cost Rate	
JHS-6	Revenue Requirement	
JHS-7	Allocation of Power Cost Deficiency	
JHS-8	Statement of Pro forma and Proposed Revenue	
JHS-9	Revised Schedule 95 Power Cost Adjustment Clause	

Q: Does this conclude your testimony?

A: Yes, it does.