[Service Date January 14, 2004]

BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of	)	DOCKET NO. UE-031389
PUGET SOUND ENERGY, INC.	)	ORDER NO. 04
For approval of its 2003 Power Cost Adjustment Mechanism Report	)	ORDER ACCEPTING AND ADOPTING SETTLEMENT; APPROVING REPORT
. . . .	)	

1 **Proceeding:** Docket No. UE-031389 is a petition by Puget Sound Energy (also referred to as PSE in this order) for Commission approval and acceptance of its 2003 Report of the effect of its power cost adjustment mechanism (also referred to as a PCA). The PCA was approved in the Company's rate increase docket UE-011570.

2 **Procedure:** The Commission convened prehearing conferences in this docket at Olympia, Washington on September 29, December 12, and December 19, 2003, before Administrative Law Judge C. Robert Wallis.

3 **Settlement Proposal:** Three of the parties to the proceeding – the Company, Commission Staff, and Public Counsel – propose a settlement of some but not all issues, and suggest that the remaining issues be addressed in pending Docket No. UE-031725. No other party objects to the proposed settlement.

4 **Appearances.** The following parties entered appearances: Puget Sound Energy, by Kirsten Dodge, attorney, Bellevue; Commission Staff, by Robert Cedarbaum, assistant attorney general, Olympia; Public Counsel Division of the Office of the Attorney General, by Simon ffitch, assistant attorney general, Seattle; Industrial Customers of Northwest Utilities (also referred to as ICNU), by Irion Sanger, attorney, Portland, Oregon; Microsoft, by Harvard Spigal, attorney, Portland,

Oregon; and the Federal Executive Agencies, by Norman Furuta, attorney, Daly City, California.

5 **Background.** In its most recent general rate case, the Commission authorized a Power Cost Adjustment Mechanism for PSE.[1] The Commission's Orders require an annual true-up of PSE's actual power costs (in contrast to the normalized prospective power costs that are generally included in rates) and an accounting of excess costs/benefits to be shared among PSE and ratepayers. To accomplish this true-up and sharing, the Company must file annual PCA reports by September 1 of each year.

6 PSE filed its first PCA report on August 28, 2003, covering the period July 1, 2002, through June 30, 2003. The report indicated net power costs of $28.17 million in excess of PCA revenues, of which the sharing mechanism allocates $24.09M to PSE and $4.09M to ratepayers.

7 Other parties asked that the matter be docketed for formal review, and the validity of the report and its underlying calculations was set for review as an adjudication in this docket pursuant to RCW 34.05.413(1).

8 **Related Proceeding.** Also pending before the Commission is a proceeding on a related topic, Docket No. UE-031725. That docket involves a prospective review of rates proposed to recover the Company's cost of power, including the pending acquisition of a new generating resource. This docket involves a retrospective review of the historical rate, although the parties and the Commission anticipate that the principles determined in this docket will apply prospectively, as well.

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[1] Twelfth and Fifteenth Supplemental Orders in Consolidated Docket Nos. UE-011570 and UG-011571, June 20, 2002 and May 13, 2003, respectively.

9 **Multiparty partial settlement.** Three of the six parties (the "Participating Parties") to this docket join in presenting a proposed partial settlement of the proceeding. The other three parties have stated on the record or in writing that they have no objection to the proposal for settlement. The Participating Parties were unable to agree in this docket upon a methodology for determining the costs of power for the Tenaska and Encogen generating resources, and they anticipate that those power cost issues will be resolved in pending Docket No. UE-031725.

10 The Settlement Stipulation states that the parties agree to a number of "corrections" to the PSE's 2003 PCA report. Appendix B of the Settlement Stipulation provides a list of those corrections. The Settlement Stipulation also identifies specific methodologies to calculate certain adjustments and true-ups for the 2003 Report and future annual PCA Reports.

11 In general, the proposed methodology would bar from consideration in the Power Cost Adjustment any money spent outside the PCA period, from July 1, 2002, through June 30, 2006. True-ups or adjustments that relate to months within the PCA period would be allowed. The methodology makes special provisions for Mid-Columbia Power Costs and Colstrip Fuel Costs because of the difficulty in determining the period or month to which certain costs relate.

12 The changes agreed to in the Settlement Stipulation would lower the calculated excess net power costs to $25.26 million, a reduction of $2.89 million from the amount identified in PSE's filed Report. Of this $25.26 million, $22.63M would be absorbed by PSE under the PCA sharing mechanism and $2.63M would flow to ratepayers.

13 **Process for Review.** No party requested an oral hearing on the proposed settlement. The Commission has reviewed the settlement proposal and the supporting materials provided with it, and finds that the proposal and the supporting materials are sufficiently straightforward and clear that no oral hearing is necessary to inform the Commission on the issues for resolution. The Commission reviews the proposal on the basis of the information filed and of record.

14 **Summary of the Power Cost Adjustment Mechanism.** Pursuant to the order in Docket No. UE-011570, the Company's PCA mechanism accounts for differences between PSE's modified actual power costs and a power cost baseline. This mechanism is approved through June 30, 2006, and allows a sharing of costs and benefits that are graduated over four levels of power cost variances.

15 **Costs That Are Considered in the PCA mechanism.** The PCA mechanism considers fixed costs, variable costs, and adjustments.

16 Fixed costs are the production-related costs from the most recent general case (or "Power Cost-only") review that, for purposes of calculating the PCA, do not change during the PCA period. These costs include the rate of return, depreciation, and property taxes for production plant and certain transmission plant.

17 Variable costs are the actual monthly amounts recorded in FERC Accounts 501 – Steam generation fuel; 547 – Other power generation fuel; 555 – Purchased power; 447 – Sales for resale; and 565 - Transmission of electricity by others. In addition, variable costs include Orders for sales of non-core gas, Transmission Revenue for Colstrip 1-4 lines, Third AC, and Northern Intertie. Allowed regulatory return on amounts associated with Tenaska, Cabot, and the Bonneville Exchange Power Agreement ("BEP") regulatory assets are also included in Variable costs.

18 Adjustments anticipated in UE-011570 include: 1) prudence from UE-921262, disallowance of a portion power costs associated with March Point 2 (3%) and Tenaska (1.2%); 2) contract price adjustments made to limit the rate or total cost per UE-011570; 3) Colstrip Availability adjustment; and 4) new-resource pricing adjustment (to bring the cost of the resource to the lower of actual unit cost or embedded rate). No adjustment was required during the first year of the PCA Mechanism for either item 3 or 4 above. All adjustments affecting the Report that is the subject of this docket are detailed in the proposed Settlement Agreement.

19 **Accounting for PCA Mechanism activity.** The Company provided detailed accounting information in the workpapers supporting this filing that track PCA Mechanism activity. A monthly calculation uses the fixed costs and actual variable power costs incurred since the implementation of the Power Cost Rate plus an estimate of the power costs to be incurred by the end of the PCA period. These costs are then adjusted for the prudence disallowance for March Point 2 and Tenaska, contract price adjustments as defined in the PCA and any adjustments required for Colstrip availability.

20 The total of allowable costs is then compared to the allowable baseline costs and any difference is allocated to the Company or customers, based on the different levels of sharing defined in the PCA Mechanism. If any of the difference between the calculated allowable costs and Baseline Power Cost is to be allocated to the customers the deferral is recorded in FERC "Account 182.3, Other regulatory assets" or "Account 254, Other regulatory credits," depending on whether the accumulated balance is a debit or credit.

21 Under the PCA Mechanism, the deferred amount at the time of the next PCA filing, along with projected variable and fixed costs through the next proposed rate year, would be considered in the determination of the rate change for the

subsequent PCA period. Amounts deferred will be amortized to FERC "Account 407.3, Regulatory debits" or "Account 407.4, Regulatory credits," as they are recovered or refunded by the Company to customers.

22 The Company accrues interest monthly on any deferred balance (debit or credit) at the interest rate calculated in accordance with WAC 480-90-233(4). As of June 30, 2003, the Company has deferred $2,629,000 of under-recovered power costs, as shown in Section 3 of this report.

23 **Energy Supply Management.** On an ongoing basis, PSE manages its energy supply portfolio with the goal of providing reliable service to its retail electric customer needs at the overall least cost. Depending on the availability of hydro energy, plant availability, fuel prices, and load fluctuations, surplus or deficit power/gas is sold or purchased in the wholesale market. The risk and financial exposure of PSE's core energy portfolio is managed through short-and intermediate-term off-system physical/financial purchases and sales and through other risk management techniques. PSE's Risk Management Committee oversees the management of the overall energy portfolio. The results of these market sales and purchases are provided in the supporting workpapers to this filing. No party challenges the prudence of energy transactions that were subject to review in this docket.

24 At times the Company has gas purchased for CTs that is not utilized for the generation of electricity. The decision to purchase or sell gas for power generation is based on market heat rate (the relationship of gas prices to power prices). The Company generally acquires natural gas supplies for the turbines to meet a probabilistic (100 scenarios) assessment, which includes price volatility, forced outage uncertainty, as well as retail load and hydroelectric generation variability assumptions in advance of actually needing the gas. As a means to manage the risk and financial exposure of our portfolio the Company actively manages this probabilistic position on a forward-looking basis. Specifically, if the market heat rate decreases the Company will sometimes sell excess natural gas and replace the assumed generation with power purchases. Conversely, as the heat rate increases, it will sometimes purchase additional natural gas. As the delivery month approaches, it shifts to a more deterministic method of managing risk in the portfolio and will generally purchase or sell excess gas for power.

25 Gas financial purchases or sales are considered in determining fuel costs for gas generation plants. The PSE gas traders may enter into financial trades to hedge the actual costs of natural gas. The trader has the option of taking a fixed or floating price position on the financial trades. The financial hedging decision is determined by a number of factors, including the heat rate of the plant, the market heat rate, and how much physical volume would be purchased at market prices. Once the decision is made on what gas to hedge financially, a deal ticket is prepared that indicates the generation plant that will be allocated any gain or loss. The financial deals that are used to hedge the gas used by Tenaska are allocated to FERC Account 456 to offset the costs of the actual fuel that is expensed to FERC Account 456. The financial transactions that are used to hedge the gas used by Encogen and CT's are allocated to FERC Account 547 to offset the costs of the fuel burned.

26 **Transmission costs and revenues.** Costs and revenues associated with four specific transmission lines are included in the PCA Mechanism. The Transmission lines included are the two at Colstrip, the Third AC, and the Northern Intertie. These lines bring power to PSE's system, as opposed to transmission costs that move power through PSE's system.

27 **Prudence.** Issues of prudence could be addressed in this filing. The Order in UE-011570 contemplates that the Commission has the opportunity to review prudence issues related to short-term purchases, or resources or contracts with a term of less than two years, in the evaluation of this filing. No party challenged the prudence of any transaction subject to review in this docket.

28 **The Resulting Effective Baseline Rate after considering proposed changes in the variable power cost components.** When changes in variable components of the PCA Mechanism proposed in the Settlement Agreement are considered, the baseline rate is $45.269. The variable components increase by $1.316 from the baseline rate at the time of the Settlement, $43.953.

29 **The Proposed Settlement Agreement Has No Effect on Rates.** The deferral balance is not at a level where an increase should be considered. The under-recovered amount added to the deferral balance at the end of the PCA Period, June 30, 2003, is $2,629,000.

30 **Conclusion.** Based on the information submitted by the parties, and the findings of fact and conclusions of law based thereon which are stated in the discussion above, the Commission concludes that the issues subject to review in this docket are shown to be properly considered, consistent with the Twelfth Supplemental Order in Docket No. UE-011570, consistent with sound ratemaking policy, and consistent with the public interest. The Commission therefore accepts and adopts the proposed partial stipulation, which is attached to this Order and accepts the Revised PCA Report submitted with the stipulation.

ORDER

31 The Commission Orders that the Partial Settlement Agreement proposed by Puget Sound Energy, Public Counsel, and Commission Staff in this docket, attached to this Order as Appendix A and by this reference made a part hereof, is approved and adopted as the decision of the Commission. In so doing, the Commission accepts the Revised Power Cost Adjustment Mechanism Annual Report for the 12 months ended June 30, 2003.

Dated at Olympia, Washington, and effective this 14th day of January, 2004.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

MARILYN SHOWALTER, Chairwoman

RICHARD HEMSTAD, Commissioner

PATRICK J. OSHIE, Commissioner

NOTICE TO PARTIES: This is a final order of the Commission. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 or RCW 81.04.200 and WAC 480-07-870.

APPENDIX A

Partial Settlement Agreement