Perkins Coie

KIRSTIN S. DODGE
Direct: (425) 635-1407
Internet: ksdodge@perkinscoie.com

The PSE Building
10885 N.E. Fourth Street, Suite 700
Bellevue, WA 98004-5579
PHONE: 425.635.1400
FAX: 425.635.2400
www.perkinscoie.com

VIA EMAIL & HAND DELIVERY

December 19, 2003

Ms. Carole J. Washburn
Washington Utilities and Transportation
Commission
1300 S. Evergreen Park Drive SW
Olympia, WA 98504

Re: Docket No. UE-031389
Partial Settlement Stipulation

Dear Ms. Washburn:

Enclosed are an original and 12 copies of the parties' Partial Settlement Stipulation ("Partial Settlement") in the above-referenced matter. Please note that the Partial Settlement contains information that is **CONFIDENTIAL PER PROTECTIVE ORDER IN WUTC DOCKET NO. UE-031389**, thus we have provided the original and 12 copies in a sealed envelope. We have also provided one redacted copy of the Partial Settlement for the public record.

For accounting purposes, Puget Sound Energy, Inc. ("PSE") respectfully requests that the Commission issue an order approving the Partial Settlement by January 15, 2004.

Please return a conformed copy in the enclosed self-addressed envelope. Thank you for your assistance.

Very truly yours,

Kirstin S. Dodge

KSD:pli
Enclosures
cc: All Parties of Record

[07772-1206/BA033530.008]

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of PUGET SOUND ENERGY, INC. For Approval of 2003 Power Cost Adjustment Mechanism Report	DOCKET NO. UE-031389 PARTIAL SETTLEMENT STIPULATION

I. INTRODUCTION

1. This Stipulation is entered into this 19th day of December, 2003, by and between: Puget Sound Energy, Inc. ("PSE" or the "Company"), the Staff of the Washington Utilities and Transportation Commission ("Staff"), and the Public Counsel Section of the Attorney General's Office ("Public Counsel") (referred to hereinafter jointly as the "Participating Parties" and individually as a "Participating Party").

2. The Participating Parties hereby voluntarily agree to this Partial Settlement Stipulation to resolve a number of issues in dispute among them regarding PSE's Power Cost Adjustment Mechanism Annual Report For The Twelve Months Ended June 30, 2003 ("2003 PCA Report"). The Participating Parties understand that this Partial Settlement Stipulation is subject to Commission approval, and hereby respectfully request that the Commission issue an order approving this Partial Settlement Stipulation.

Perkins Coie LLP
The PSE Building
10885 N.E. Fourth Street, Suite 700
Bellevue, WA 98004-5579
Phone: (425) 635-1400
Fax: (425) 635-2400

II. PROCEDURAL BACKGROUND

3. In the Commission's Twelfth Supplemental Order in Docket Nos. UE-011570 and UG-011571 ("Twelfth Supplemental Order"), the Commission approved the parties' Settlement Stipulation for Electric and Common Issues for PSE's most recent general rate case ("Stipulation"). Among other things, the Twelfth Supplemental Order authorized a Power Cost Adjustment Mechanism (PCA). Exhibit A to the Stipulation, which is attached to the Twelfth Supplemental Order, sets forth details regarding the PCA, and is hereinafter referred to and cited as the "PCA Settlement."

4. Following verification of certain numbers set forth in the exhibits to the PCA Settlement, the Commission ordered that revised pages of Exhibits A, B, D and F be substituted for the corollary pages of Exhibits A, B, D and F of the PCA Settlement. The Commission further ordered that the resulting adjusted calculations be used for purposes of the PCA accounting required by the PCA Settlement beginning July 1, 2002. *See* Fifteenth Supplemental Order in Docket Nos. UE-011570 and UG-011571 (May 13, 2003) ("Fifteenth Supplemental Order").

5. The PCA Settlement describes the PCA as

> a mechanism that would account for differences in PSE's modified actual power costs relative to a power cost baseline. This mechanism would account for a sharing of costs and benefits that are graduated over four levels of power cost variances, with an overall cap of $40 million (+/-) over the four year period July 1, 2002 through June 30, 2006. If the cap is exceeded, costs and benefits in excess of $40 million would be shared at a different level of sharing.

PCA Settlement, ¶ 2. The PCA Settlement sets forth the various levels of costs and benefits sharing between the Company and its Customers, and provides that "[t]he customer's share of the power cost variability will be deferred as described below…." *Id.* at ¶ 3.

Perkins Coie LLP
The PSE Building
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6. In order to implement its sharing provisions and overall cap, the PCA Settlement requires an annual true-up of actual power costs (versus the normalized level set in rates) and an accounting of sharing amounts. To accomplish this, the PCA Settlement provides that:

- In August of 2003 and each year thereafter, the Company shall file an annual report detailing the power costs included in the deferral calculation, in a form satisfactory to the Commission, for Commission review and approval. The Commission shall have an opportunity to review the prudence of the power costs included in the deferred calculation, and costs determined to be imprudent can be disallowed at that time. Staff and other interested parties will have the opportunity to participate in the prudence review process.

PCA Settlement, ¶ 4.

7. In compliance with the PCA Settlement and Twelfth and Fifteenth Supplemental Orders, on August 28, 2003, PSE filed a Petition for review and approval of its 2003 PCA Report. At the prehearing conference on September 29, 2003, the parties agreed that it might be possible to reach consensus with respect to whether some or all of the 2003 PCA Report complied with the Twelfth Supplemental Order and PCA Settlement. The Administrative Law Judge set a deadline of December 5 for filing any proposed settlement. Discovery commenced, and the parties convened a series of conference calls to discuss the progress of investigation into the 2003 PCA Report and a variety of issues that were potentially disputed.

8. As a result of these discussions, PSE has agreed to make several corrections to its 2003 PCA Report suggested by Staff. The Participating Parties have also agreed to a methodology for calculating a number of adjustments and true-ups for the 2003 PCA Report and future annual PCA Reports filed pursuant to the PCA Settlement, ¶ 4. These agreements resolve all but one issue regarding PSE's 2003 PCA Report, as further described below.

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III. PARTIAL SETTLEMENT AND REQUEST FOR APPROVAL

A. Carve-out of Impasse Issue

9. The Participating Parties have agreed that only the following issue remains unresolved in this proceeding:

- Fuel costs for Tenaska and Encogen/Cabot: Staff and Public Counsel object to the amount of fuel costs for the Tenaska and Encogen natural gas-fired cogeneration projects.

10. The Participating Parties specifically carve out and exclude the impasse issue described in paragraph 9, above, from the partial settlement set forth in this stipulation, and acknowledge that a hearing will need to be set to litigate the impasse issue.

B. Partial Settlement and Request for Approval

11. Except for the impasse issue described in Section III.A., above, the Participating Parties have resolved all other issues with respect to PSE's 2003 PCA Report.

12. The Participating Parties have agreed to a methodology for treating "out of PCA period" items. Exhibit A hereto defines and outlines the agreed upon treatment for such costs.

13. The Participating Parties agree that certain adjustments must be made to the 2003 PCA Report as a result of the methodologies described in Exhibit A hereto, and also agree that certain corrections should be made to the 2003 PCA Report. Such adjustments and corrections are described in Exhibit B hereto.

14. The revised 2003 PCA Report attached hereto as Exhibit C reflects changes to PSE's original filing necessary to incorporate the corrections and agreements described in paragraph 13, above, and Exhibit B. The Participating Parties recognize that further

Perkins Coie LLP
The PSE Building
10885 N.E. Fourth Street, Suite 700
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revisions to the 2003 PCA Report may or may not be required as a result of the outcome of litigation over the impasse issue described in Section III.A., above.

15. The Participating Parties expressly agree that the methodologies set forth in paragraph 12, above, and Exhibit A hereto should be used to calculate not only PSE's 2003 PCA Report, but also future annual PCA Reports filed pursuant to the PCA Settlement, ¶ 4.

16. This Partial Settlement Stipulation is presented to the Commission under WAC 480-09-465 (Alternative Dispute Resolution) for the Commission's approval. Except with respect to the question whether further revisions to the 2003 PCA Report will be required as a result of the outcome of litigation over the impasse issue described in Section III.A., above, each Participating Party agrees that the issues resolved in this Partial Settlement Stipulation, and the revised 2003 PCA Report attached hereto as Exhibit C, comply with the Commission's Twelfth and Fifteenth Supplemental Orders and PCA Settlement and/or are fair, just, reasonable and sufficient.

C. Miscellaneous Provisions

17. The Participating Parties agree to the following miscellaneous terms with respect to the Partial Settlement Stipulation:

18. **Binding on Parties:** Each Participating Party agrees to support the terms and conditions of this Partial Settlement Stipulation. The Participating Parties understand that this Partial Settlement Stipulation is subject to Commission approval.

19. **Integrated Terms of Settlement:** This Partial Settlement Stipulation represents an integrated resolution of issues. Accordingly, the Participating Parties recommend that the Commission adopt this Partial Settlement Stipulation in its entirety. If the Commission rejects all or any material portion of this Partial Settlement Stipulation, or adds additional material conditions, each Participating Party reserves the right, upon written

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notice to the Commission and all parties to this proceeding within five (5) business days of the date of the Commission's Order, to withdraw from this Partial Settlement Stipulation. For purposes of this paragraph, each Participating Party shall determine materiality and shall do so in good faith. If any Participating Party exercises its right of withdrawal, the Partial Settlement Stipulation shall be void and of no effect, and the Participating Parties will support a joint motion to establish a procedural schedule to litigate disputed issues.

20. **Negotiated Agreement:** This Partial Settlement Stipulation represents a fully negotiated agreement. Each Participating Party has been afforded the opportunity, which it has exercised, to review the terms of the Partial Settlement Stipulation. Each Participating Party has been afforded the opportunity, which it has exercised, to consult with legal counsel of its choice concerning such terms and their implications. The Partial Settlement Stipulation shall not be construed for or against any Participating Party based on the principle that ambiguities are construed against the drafter.

21. **Procedure:** The Participating Parties shall cooperate in submitting this Partial Settlement Stipulation promptly to the Commission for approval. The Participating Parties agree to cooperate, in good faith, in any further activities that may be necessary to support and explain the basis of this Partial Settlement Stipulation.

22. **No Precedent:** The Participating Parties enter into this Partial Settlement Stipulation and the attached Issue Agreements to avoid further expense, uncertainty, and delay. By executing this Partial Settlement Stipulation, no Participating Party shall be deemed to have accepted or consented to the facts, principles, methods, or theories employed in arriving at the Partial Settlement Stipulation, and except to the extent expressly set forth in this Partial Settlement Stipulation, no Participating Party shall be deemed to have

Perkins Coie LLP
The PSE Building
10885 N.E. Fourth Street, Suite 700
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Phone: (425) 635-1400
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agreed that this Partial Settlement Stipulation is appropriate for resolving any issues in any other proceeding.

23. **Execution:** This Partial Settlement Stipulation may be executed by the Participating Parties in several counterparts, through original and/or facsimile signature, and as executed shall constitute one agreement.

DATED this 19th day of December, 2003.

PUGET SOUND ENERGY, INC.

By James W. Eldredge
James W. Eldredge
Vice President, Corporate Secretary
and Chief Accounting Officer

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION STAFF

By ______________________
Robert Cedarbaum
Assistant Attorney General

PUBLIC COUNSEL SECTION, OFFICE OF THE ATTORNEY GENERAL OF THE STATE OF WASHINGTON

By ______________________
Simon ffitch
Assistant Attorney General
Public Counsel Section Chief

Perkins Coie LLP
The PSE Building
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agreed that this Partial Settlement Stipulation is appropriate for resolving any issues in any other proceeding.

23. **Execution:** This Partial Settlement Stipulation may be executed by the Participating Parties in several counterparts, through original and/or facsimile signature, and as executed shall constitute one agreement.

DATED this 18th day of December, 2003.

PUGET SOUND ENERGY, INC.

By ____________________
Kimberly Harris
Vice President of Regulatory Affairs

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION STAFF

By ____________________
Robert Cedarbaum
Assistant Attorney General

PUBLIC COUNSEL SECTION, OFFICE OF THE ATTORNEY GENERAL OF THE STATE OF WASHINGTON

By ____________________
Simon ffitch
Assistant Attorney General
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Perkins Coie LLP
The PSE Building
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DATED this 19th day of December, 2003.

PUGET SOUND ENERGY, INC.

By ______________________
Kimberly Harris
Vice President of Regulatory Affairs

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION STAFF

By ______________________
Robert Cedarbaum
Assistant Attorney General

PUBLIC COUNSEL SECTION, OFFICE OF THE ATTORNEY GENERAL OF THE STATE OF WASHINGTON

By ______________________ for:
Simon ffitch
Assistant Attorney General
Public Counsel Section Chief

Perkins Coie LLP
The PSE Building
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Methodology for Adjustments of Costs Outside of the PCA Period

A. Adjustments for Costs prior to July 1, 2002:

Power cost entries, true-ups and adjustments posted in the current month for months prior to the beginning of the PCA, July 1, 2002, will be excluded from power costs in the monthly PCA calculation. Note the exceptions in item D., below.

B. Adjustments for Costs Recorded After Termination of PCA Mechanism:

Power cost adjustments posted in the month following the termination of the PCA Mechanism relating to the PCA periods will be included in power costs for the month of the final PCA calculation and the deferral will be adjusted accordingly. Note the exceptions in item D., below.

C. Adjustments for Previous PCA Periods:

1. Power cost adjustments or true-ups for prior periods that fall within the PCA mechanism period (July 1, 2002 forward) are included as recoverable power costs under the PCA mechanism. Adjustments for previous PCA periods that are equal to or less than $1 million (debit or credit) will flow through the current month PCA calculation. Note the exceptions in item D below.

2. Adjustments or true-ups greater than $1 million (5% of the $20 million 'deadband') (debit or credit) that relate to prior PCA periods will be flowed through a recalculation of the previous PCA period for regulatory purposes. Any changes to the customer deferrals from the prior PCA period will be indicated in a reconciliation schedule for deferrals by PCA period. Note the exceptions in item D., below.

D. Exceptions:

Exceptions will be made for items A, B and C adjustments for the following power costs:

1. **Company Accounting Errors:**
For all accounting errors made by the Company, except for Colstrip fuel costs, if an error has been made in regard to accounting for power cost transactions, to the extent that the Company should have known at the time of the transaction, the Company will reflect the appropriate adjustment to the appropriate PCA period(s) and adjust the deferral for the period (s) accordingly.

2. **Mid-Columbia Power Costs:**

PSE books debt and O&M expense as billed from the Mid-Columbia Public Utility Districts, each dam is identified below. Current month power cost expense equal the current month debt service cost plus an estimate of actual O&M costs. This estimation is calculated differently for different Dams. PSE does not accrue for estimated true-ups to monthly O&M billed costs. Subsequent to the PUD's annual audits, PSE receives a bill or credit for any prior year adjustments. For example, Chelan PUD (Rocky Reach & Rock Island I & II) operates on a calendar year and audit true ups are normally received in May of the following year.

Since it is difficult to determine to what month(s) the annual true-ups actually impact, audit true-ups for the MidC projects should be treated as debits or credits in the PCA period those adjustments are normally found, see below. If the annual true-ups are booked in a month, other than that listed below, which causes them to be recorded in a different PCA period, then the treatment of adjustments as identified in item C above apply. These annual true-ups include the Douglas County PUD Settlement Agreement that is typically a credit.

Normal true up periods for PSE Mid Columbia resources
Priest Rapids and Wanapum are trued-up in April for the prior calendar year.
Rocky Reach and Rock Islands 1 and 2 are trued-up in May for the prior calendar year.
Wells, the year ended August is trued-up in the following months, September through December.

3. <u>Colstrip Fuel Costs</u>

Monthly fuel costs represent the tonnage burned at the embedded inventory unit cost. Inventory cost represents commodity charges, royalties, reclamation accruals and true-ups from prior periods for all these types of costs. Coal inventory costs include prior period adjustments as well as corrections of accounting errors due to the difficulty in determining what period of costs are included in the beginning and ending inventory balances. Therefore, no adjustments will be made for Colstrip inventory valuation for prior period adjustments, and any true-ups or corrections from prior periods will be included in power costs at the time they become known. Adjustments for prior periods that meet the criteria in item C will be adjusted for regulatory purposes outside of the inventory valuation process.

Calculation of prior period adjustments for 2003 PCA Report based on methodologies in Exhibit A, as well as corrections to original filing:

In account 555, the following prior period adjustments are required:

Sub account	Amount	Description
109- Priest Rapid	-143,345.00	This is a reversal of April double entry
110-Wanapum	-109,437.00	This is a reversal of April double entry
116-Montana	- 34,246.44	True-up in a non Mid –C
406-MPCC-1 Disp	-340,926.78	July entries truing-up June, company made wrong Adj
408-MPCC-2 Disp	54,973.04	July entries truing-up June, company made wrong Adj
Sub-total	**$ -572,982.18**	
516-Powerex Exch	$-2,829,115,11	Reverse company prior period
Total prior period Additions	**$-3,402,097.29**	

Calculation of regulatory asset balance

Staff calculation of the actual AMA for regulatory assets assumes that interest was accumulated on assets to the beginning of the originally proposed rate year, September 3, 2002. The company accumulated interest through the end of 2002 in accordance with the original accounting order issued under Docket No. UE-971619. The Participating Parties agree to use Staff's calculation. As a result, the amount shown on line 20 of Exhibit B changes from $32,911,879 to $32,746,609. The revised number is based on a total average of monthly average balance for the regulatory assets of $291,579,399. This amount is comprised of: Cabot at $12,376,708, Tenaska at 228,066,750, and BEP at $51,135,941.

Resulting Adjustment
To Company Presentation **$-165,270**

Firm Wholesale Adjustment

Staff identified an error in the calculation of the Firm Wholesale Adjustment. The appropriate calculation allocates a percentage of the imbalance to firm wholesale customers. The allocation is determined by dividing actual sales for resale KWhs divided by total retail sales for the year.

Resulting Adjustment
To Company Presentation **$ 339,557.**

Adjustments to PSE's original filing:

Wasco and Spokane contracts are included in the Schedule E price limitation calculations. Like the NUG contracts, these contracts have seasonal prices. The Participating Parties agree that the portion of the disallowances related to the difference in summer winter mix from that projected was inappropriate and therefore agreed to do these contracts on a seasonal basis.

North Wasco
The Wasco limit of $0.0628 per KWh in the exhibit breaks down to a winter limit of $0.07832 per KWh and a summer limit of $0.04344 per KWh.
There was also an error in the company-proposed Schedule E relating to Wasco. The company utilized 41,561,000 KWh, while the invoices supported 41,499,000 KWh.
As a result of these changes, the North Wasco adjustment in Schedule E of $80,992 is reduced to $44,601.

Spokane MSW
The Wasco limit of $0.0875 per KWh in the exhibit breaks down to a winter limit of $0.10717 per KWh and a summer limit of $0.06394 per KWh.
There was also an error in the company proposed Schedule E relating to Spokane. The company utilized 136,561,000 KWh, while the invoices supported 136,413,000 KWh.
As a result of these changes, the Spokane MSW adjustment in Schedule E of $287,072 is reduced to $5,690.

Koma Kulshan Hydro
A small adjustment to schedule E should be made related to Schedule E dollars not agreeing with invoices. The revised adjustment is $10,926 compared to $10,555.

NUG Schedule E calculations
The March Point and Sumas limits in Schedule E were not calculated consistent with the PCA Settlement, which indicates that the NUG rate limits were to be calculated as if no displacement had occurred. Note this is the method the company utilized on Tenaska.

These changes did not impact the calculation of the adjustments for Sumas, March Point 2 or the summer pricing of March Point 1, but a small adjustment resulted in the winter portion of March Point 1.

March Point 1-Winter
A small adjustment of $2,262 resulted from the recalculation of this portion of the March Point 1 contract.

Resulting Schedule E
As a result, the Schedule E total adjustment is $346,150 instead of $661,290

PUGET SOUND ENERGY

Power Cost Adjustment Mechanism Annual Report

(Revised)

Twelve Months Ended June 30, 2003

Puget Sound Energy
Power Cost Adjustment Mechanism
Annual Report
Twelve Months Ended June 30, 2003

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Puget Sound Energy
PCA Mechanism
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Twelve Months Ended June 30, 2003

PCA Settlement Stipulation - Exhibit A-1 Power Cost Rate

Row		Test Year	Test Yr $/MWh		Rate Year
13	Regulatory Assets (Variable)	$ 284,728,294			
14	Transmission Rate Base (Fixed)	124,643,364			
15	Production Rate Base (Fixed)	493,777,165			
16		$ 903,148,823			
17	Net of tax rate of return	7.30%			
18					
19					
20	Regulatory Asset Recovery	$ 31,977,178	$ 1.677	(c)	
21	Fixed Asset Recovery-Prod Factored	54,142,951	$ 2.840	(a)	55,725,557
22	Fixed Asset Recovery Other	15,310,432	$ 0.803	(a)	15,310,432
23	501-Steam Fuel	32,511,186	$ 1.705	(c)	
24	555-Purchased power	526,980,333	$ 27.643	(c)	
25	557-Other Power Exp	11,499,089	$ 0.603	(a)	11,835,209
26	547-Fuel	61,173,325	$ 3.209	(c)	
27	565-Wheeling	41,435,360	$ 2.174	(c)	
28	Variable Transmission Income	(6,510,985)	$ (0.342)	(c)	
29	Hydro and Other Pwr.	51,597,583	$ 2.707	(a)	53,105,787
30	447-Sales to Others	(37,525,193)	$ (1.968)	(c)	
31	456-Subaccounts 00012 & 00018 and 00035 & 00036	1,077,379	$ 0.057	(c)	
32	Transmission Exp - 500KV	342,495	$ 0.018	(a)	352,506
33	Depreciation-Production	36,265,740	$ 1.902	(a)	37,325,792
34	Depreciation-Transmission	4,851,654	$ 0.254	(a)	4,851,654
35	Property Taxes-Production	8,343,174	$ 0.438	(a)	8,600,747
36	Property Taxes-Transmission	4,441,860	$ 0.233	(a)	4,441,860
37	Subtotal & Baseline Rate	$ 837,913,560	**$ 43.953**	(b)	191,549,544
38	Revenue Sensitive Items	0.9552337			
39		$ 877,181,741			
40	Test Year Load (MWH's)	19,063,867	<-- includes Firm Wholesale		
41		Before Rev. Sensitive Items	After Rev. Sensitive Items		
42	Power Cost in Rates with Revenue Sensitive Items (the adjusted baseline		46.013		
43	sum of (a) = Fixed Rate Component	9.798	10.257		
44	(b) = Power Cost Rate	43.953	46.013		
45		34.155	35.756		
46	sum of (c) = Variable Power Rate Component				
47					
48	* Regulatory Assets are Tenaska, Encogen Fuel Buyout and BEP				

Puget Sound Energy
PCA Mechanism
Annual Report
Twelve Months Ended June 30, 2003

PCA Settlement Stipulation - Exhibit A-1 Power Cost Rate Updated

Row		PCA Period 12 Mo End 6/30/03		
13	Regulatory Assets (Variable)	$ 291,579,520		
14	Transmission Rate Base (Fixed)	124,643,364		
15	Production Rate Base (Fixed)	493,777,165		
16		$ 911,471,503		
17	Net of tax rate of return	7.30%		
18			PCA Periodd 12 Mo End 6/30/03	
20			$/MWh	
21	Regulatory Asset Recovery	$ 32,746,623	$ 1.707	(c)
22	Fixed Asset Recovery-Prod Factored	55,725,557	$ 2.905	(a)
23	Fixed Asset Recovery Other	15,310,432	$ 0.798	(a)
24	501-Steam Fuel	31,562,320	$ 1.645	(c)
25	555-Purchased power	721,831,560	$ 37.630	(c)
26	557-Other Power Exp	11,835,209	$ 0.617	(a)
27	547-Fuel	28,191,542	$ 1.470	(c)
28	565-Wheeling	39,906,926	$ 2.080	(c)
29	Variable Transmission Income	(6,997,053)	$ (0.365)	(c)
30	Hydro and Other Pwr.	53,105,787	$ 2.768	(a)
31	447-Sales to Others	(166,771,845)	$ (8.694)	(c)
32	456-Subaccounts 00012 & 00018 and 00035 & 00036	(3,624,989)	$ (0.189)	(c)
33	Transmission Exp - 500KV	352,506	$ 0.018	(a)
34	Depreciation-Production	37,325,792	$ 1.946	(a)
35	Depreciation-Transmission	4,851,654	$ 0.253	(a)
36	Property Taxes-Production	8,600,747	$ 0.448	(a)
37	Property Taxes-Transmission	4,441,860	$ 0.232	(a)
38	Subtotal & Baseline Rate	$ 868,394,629	**$ 45.269**	(b)
39	Revenue Sensitive Items	0.9552337		
40		$ 912,129,739		
41	Rate Year Load	19,182,454	<-- includes Firm Wholesale	
42		Before Rev. Sensitive Items	After Rev. Sensitive Items	
43	Power Cost in Rates with Revenue Sensitive Items (the adjusted baseline		47.390	
44	sum of (a) = Fixed Rate Component	9.985	10.453	
45	(b) = Power Cost Rate	45.269	47.390	
46		35.284	36.938	
47	sum of (c) = Variable Power Rate Component			
48				
49	* Regulatory Assets are Tenaska, Encogen Fuel Buyout and BEP			

Puget Sound Energy
PCA Mechanism
Annual Report
Twelve Months Ended June 30, 2003

PCA Settlement Stipulation - Exhibit B- PCA Mechanism Calculation (REVISED)

Row		FERC Acct.	Period to Date	Explanation or source
6				
7	Return on Fixed RB		$ 55,725,557	from Schedule A-1 NEW line 11 - Fixed Asset Recovery adjust to monthly basis.
8	Other Fixed Costs		$ 135,823,988	from Schedule A-1 NEW lines 12,15,19,22,23,24,25 & 26 (1)
9	Subtotal Fixed Costs		$ 191,549,544	from Schedule A-1 NEW line 27 - Subtotal adjusted to monthly basis.
10	Total Variable Component Actual			
11	Steam Oper. Fuel	501	$ 31,562,320	SAP - actual Report GR55 Group Z006 (do not include true-ups prior to July 2002).
12	Other Pwr Gen Fuel	547	28,191,542	SAP - actual Report GR55 Group Z006 (do not include true-ups prior to July 2002).
13	Other Elec Revenues	45600012,18,35, 36,100,101,130,131	(3,624,989)	SAP - actual Report GR55 Group Z006 (do not include true-ups prior to July 2002).
14	Purchase Power	555	724,312,617	SAP - actual Report GR55 Group Z006 (do not include true-ups prior to July 2002).
15	Sales to Other Util	447	(166,771,845)	SAP - actual Report GR55 Group Z006 (do not include true-ups prior to July 2002).
16	Wheeling	565	39,906,926	SAP - actual Report GR55 Group Z006 (do not include true-ups prior to July 2002).
17	Transmission Revenue	45600017	(6,997,053)	SAP - actual Report GR55 Group Z006, Transmission revenues on 3rd AC, Northern Intertie, Colstrip lines
18	Subtotal Variable Components		$ 646,579,533	
19				
20	Regulatory Assets	679326156	$ 32,746,623	from Exhibit D NEW line 35. (2)
21				
22	SUBTOTAL before Adjustments		$ 870,875,686	
23	**SUBTOTAL before Adjustments**		$ 870,875,686	
24	**Adjustments:**			
25	Prudence from UE-921262		$ (2,134,907)	Workpaper Section 1, Page 12, line 19 (2)
26	Contract price adjustment		(346,149)	Workpaper Section 1,Schedule E, line 41 (2)
27	Colstrip availability adjustment		-	Workpaper Section 1, Schedule F, Line 42 (2)
28	New resource pricing adjustment		-	Workpaper Section 1, Schedule G, line 39 (2)
29	Firm Wholesale Cost adjustment		See Adjustment on Line 39.	.04% of Subtotal Schedule B line 22
30	Subtotal Adjustments		$ (2,481,057)	
31				
32	**Total allowable cost (line 28/line 30)**		$ 868,394,629	
33				
34	PCA period delivered load (Kwh)		19,182,454,092	From Subtotal line on Sales of Electricity Report
35	**Baseline Power Cost**	$0.043953	$ 843,126,409	Base line rate from Schedule A-1 NEW line 27
36				
37	Imbalance for Sharing		$ 25,268,220	
38			$ 25,268,220	
39	**Less Firm Wholesale**	0.0404%	$ 25,258,000	
40	**Gross PCA**		$ 25,258,000	18230281
41	**Gross PCA Contra**		$ (25,258,000)	18230291
42				
43	**Cumulative Gross PCA**		$ 25,258,000	18230281
44	**Cumulative Gross PCA Contra**		$ (25,258,000)	18230291
45				
46	Note: This schedule was derived from original PCA Collaborative Exhibit B			

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POWER COST ADJUSTMENT SUMMARY

PCA Period 1 Power Costs:

Actual	$	868,394,630
Baseline		843,126,410
Difference	$	25,268,220
Wholesale Customers		(10,220)
Total Cost Over Baseline	$	25,258,000

Allocation of PCA Period 1 Power Costs:

Company	$	22,629,000
Customers		2,629,000
Total Cost Allocated	$	25,258,000

Schedule E - Contract Adjustments

Row		Limit - Rate or Total Cost per UE-011570	Period to Date Total Cost + Replacement Energy Cost for Displ NUGS $	Period to Date Actual Rate $/kwh*	Period to Date Rate Change*	Adjust for Positive Differences
7	CONTRACTS					
8	Baker Replacement			[redacted]		
9	BC Hydro Point Roberts	$ 0.0670	$ 1,270,589			
10	BPA WNP-3 Exchange Power	$ 0.0282	$ 10,754,362			
11	BPA WNP3 Return					
12	BPA Snohomish Conservatior	$ 0.0514	$ 3,646,452			
13	CSPE					
14	Mid-Columbia					
15	Canadian Entitlement and CEA-EA					
16	MPC Firm Contract-Demanc	$ 29,382,000	$ 28,980,276			
17	MPC Firm Contract-Energy					
18	PPL Contract 15 yr					
19	Supplemental Entitlement Car					
20	North Wasco Winter	$ 0.0783	$ 1,931,110			
20A	North Wasco Summer	$ 0.0434	$ 761,886			
21	WWP Contract 15 yr					
22	PG&E Exchange Storage Acctg.					
23	QF Shipp Hutch. Creek	$ 0.0300	$ 94,988			
24	QF Koma Kulshan Hydrc	$ 0.0749	$ 3,211,814			
25	QF March Point Cogen 1 Winter	$ 0.0610	$ 25,432,258			
26	QF March Point Cogen 1 Summer	$ 0.0437	$ 12,226,801			
27	QF March Point Cogen 2 Winter	$ 0.0660	$ 21,257,410			
28	QF March Point Cogen 2 Summer	$ 0.0553	$ 11,822,210			
29	QF Port Townsend Hydrc	$ 0.0282	$ 52,705			
30	QF PERC Puyallup					
31	QF Spokane MSW Winter	$ 0.1072	$ 8,753,902			
31A	QF Spokane MSW Summer	$ 0.0636	$ 3,487,274			
32	QF Sumas Winter	$ 0.0818	$ 53,376,630			
33	QF Sumas Summer	$ 0.0592	$ 26,643,253			
34	QF Sygitowicz	$ 0.0514	$ 27,392			
35	QF Tenaska (excl. Reg. Amort.)	$ 0.0318	$ 62,734,813			
36	QF Twin Falls	$ 0.0750	$ 4,661,400			
37	QF Weeks Falls	$ 0.0750	$ 852,075			
38	Skookumchuck			Reverse sign and enter on line 42		$ 346,150
47	TOTAL					$ (346,150)
48	To Exhibit B line 22					

*note numbers may not add due to rounding

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Schedule X- March Point and Tenaska Disallowance

		Period To Date
		July 02 - June 03
1	March Point 2 Invoice Cost	$ 28,439,116
2	MP2 Rate Adjustment	-
3	MP2 for Prudence Adjustment	$ 28,439,116
4	Prudence adjustment %	3%
5	Prudence adjustment	**$ 853,173**
6		
7	Tenaska Invoice Cost	$ 107,073,656
8	Tenaska Rate Adjustment	262,504
9	Tenaska for Prudence Adjustment	$ 106,811,151
10	Prudence adjustment %	1.2%
11	Tenaska Prudence Adjustment	**$ 1,281,734**
12	**TOTAL Prudence Adjustment**	**$ 2,134,907**
	Input to Exhibit B, line 25	$ (2,134,907)

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EXPLANATORY Q & A

What is the purpose of this filing?
In the Commission's Twelfth Supplemental Order in Docket No. UE-011570, the Commission approved the Settlement Stipulation which resolved all electric issues and common electric-natural gas issues in PSE's consolidated rate proceeding, as well as some natural gas issues. The Stipulation defines the agreement reached regarding the establishment of and methodology used, as well as provides for reporting requirements, for the Company's Power Cost Adjustment (PCA) Mechanism. Regarding reporting requirements, the Stipulation requires the Company to file an annual report detailing the power costs included in the PCA deferral calculation. Through its Petition, the Company is requesting approval of the PCA Mechanism activity for the twelve months ended June 30, 2003 including the deferral of under-recovered power costs of $2,629,000. The amount deferred represents excess power costs over those included in the baseline rate considering the application of PCA sharing bands.

What is the effective baseline rate at the end of the PCA Period when changes in the variable power cost components are considered?
As shown on Exhibit A-1 Power Cost Rate Updated, Section 2 of this report, when changes in variable components of the PCA Mechanism are considered the baseline rate is $45.269. The variable components increased by $1.316 from the baseline rate at the time of the Settlement, $43.953 (Exhibit A-1 Power Cost Rate, Section 1 of this report).

Will there be a rate increase as a result of this filing?
No. The deferral balance is not at a level where an increase is warranted. As noted above, the under-recovered balance deferred at the end of the PCA Period, June 30, 2003 was $2,629,000.

Please provide a brief summary of the Power Cost Adjustment Mechanism.
As authorized by the Commission, the Company's PCA mechanism accounts for differences in PSE's modified actual power costs relative to a power cost baseline. This mechanism accounts for a sharing of costs and benefits that are graduated over four levels of power cost variances, with an overall cap of $40 million (+/-) for the four year period July 1, 2002 through June 30, 2006. If the cap is exceeded, costs and benefits in excess of $40 million would be allocated 99% to the customers and 1% to the Company. See Attachment A, Stipulation, which define the specific sharing levels and conditions.

Please explain what categories of power costs are included in the PCA mechanism.
The following fixed and variable power costs are included. These costs are adjusted as described below.

Fixed Costs:
Fixed costs are the power production related costs from the most recent general case or Power Cost only review which 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

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EXPLANATORY Q & A (cont.)

plant and specifically identified transmission plant. Other fixed costs include FERC Accounts 557 Other production expense, Hydro and Other Production O&M, and 500 KV O&M.

Variable Costs:
Actual monthly amounts recorded in FERC Accounts 501 – Steam generation fuel, 547 – Other power generation fuel, 555 – Purchased power, 447 – Sales for resale, 565 – Transmission of electricity by others as well as Orders for sales of non-core gas 45600012, 45600018, 45600035, 45600036 and 45600017 Transmission Revenue for Colstrip 1-4 lines, Third AC and Northern Intertie are included. Allowed regulatory return on amounts associated with Tenaska, Cabot and the Bonneville Exchange Power Agreement ("BEP") regulatory assets are also included in Variable costs.

Adjustments:
Adjustment per the Settlement Agreement 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 have been made to limit the rate or total cost per UE-011570; 3) Colstrip Availability adjustment; 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.

Please explain how the Company has tracked PCA Mechanism activity.
The Company has detailed accounting instructions, provided in the supporting workpapers to this filing, that track PCA Mechanism activity.

Each month the Company calculates the power costs subject to PCA sharing using the same methodology shown in Exhibit B from the original PCA Mechanism filing. This 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.

This total of allowable costs is then compared to the allowable baseline costs and any difference is allocated to the Company or customer 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.

Under the PCA Mechanism, the deferred amount at the time of the next PCA filing, along with the 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

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EXPLANATORY Q & A (cont.)

amortized to FERC Account 407.3, Regulatory debits or 407.4, Regulatory credits as they are recovered or refunded by the Company to customers.

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.

Can issues of prudence be addressed in this filing?
The Settlement Stipulation contemplates that the Commission has the opportunity to review prudence issues related to short-term purchases, resources or contracts with a term of less than two years, in the evaluation of this filing.

How does the Company manage its short-term resources?
On an ongoing basis, PSE manages its energy supply portfolio to reliably serve its retail electric customer needs at 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 theses market sales and purchases are provided in the supporting workpapers to this filing.

Has the Company engaged in long term resource transactions (longer than two years) since the settlement that were effective in the PCA period?
No.

What is the Company's procedure regarding the sale of gas purchased for CTs but 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 heat rates decrease we will sometimes sell off any excess natural gas and replace the assumed generation with power purchases. Conversely, as heat rates increase we will sometimes purchase additional natural gas. As we approach and then enter

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EXPLANATORY Q & A (cont.)

delivery month we shift to a more deterministic method of managing risk in the portfolio and will generally purchase or sell excess gas for power.

How are the gas financial purchases or sales credited to fuel costs for gas generation plants?
The PSE gas traders may enter into financial swaps to hedge our actual costs of natural gas with various counterparties The trader has the option of taking a fixed or floating price position on the financial swaps. 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 will be purchased at market prices. Once the decision is made on what gas to financially hedge, a deal ticket is prepared which indicates the generation plant that will be allocated the 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.

What transmission costs and revenues are included in the PCA?
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.

CERTIFICATE OF SERVICE

Docket No. UE-031389

I hereby certify that on this day I caused to be served via electronic mail and regular U.S. mail, postage prepaid, a true and correct copy of the attached Partial Settlement Stipulation to the individuals listed below:

Robert Cedarbaum
Washington Utilities & Transportation Commission
1400 S. EveregreenPark Drive S.W.,
Olympia, WA 98504
bcedarba@wutc.wa.gov

Simon ffitch
Washington State Attorney General's Office
900 Fourth Avenue, Suite 2000
Seattle,WA 98164-1012
simonf@atg.wa.gov

Irion Sanger
S. Bradley Van Cleve
Davison Van Cleve
1000 SW Broadway, Suite 2460
Portland, OR 97205
ias@dvclaw.com

Mr. Norman Furuta
Associate Counsel
Department of the Navy
2001 Junipero Serra Blvd., Suite 600
Daly City, CA 94014-1976
furutanj@efawest.navfac.navy.mil

Harvard Spigal
Preston Gates & Ellis
222 SW Columbia Street, Suite 1400
Portland, OR 97201-6632
hspigal@prestongates.com

Dated this 19th day of December, 2003.

Pam Iverson