

**EXHIBIT NO. \_\_\_\_ (JHS-3)**  
**DOCKET NO. \_\_\_\_\_**  
**2005 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-\_\_\_\_\_**

**SECOND EXHIBIT TO THE PREFILED DIRECT TESTIMONY OF  
JOHN H. STORY (NONCONFIDENTIAL)  
ON BEHALF OF PUGET SOUND ENERGY, INC.**

**JUNE 7, 2005**

**Exhibit A to  
Settlement Stipulation**

**PSE GENERAL RATE CASE  
DOCKET NOS. UE-011570 and UG-011571**

**SETTLEMENT TERMS FOR THE  
POWER COST ADJUSTMENT MECHANISM (PCA)**

**A. Executing Parties**

1. The following parties have participated in the Power Cost Adjustment mechanism (PCA) collaborative in Docket Nos. UE-011570 and UG-011571, and have reached consensus on the terms of settlement with respect to such issues, as set forth in this Agreement: Puget Sound Energy, Inc. ("PSE" or the "Company"); the Staff of the Washington Utilities and Transportation Commission; the Public Counsel Section of the Attorney General's Office; Intervenor the Kroger Co.; Intervenor AT&T Wireless Services, Inc.; Intervenor NW Energy Coalition and Natural Resources Defense Council; Federal Executive Agencies; and Intervenor Cogeneration Coalition of Washington (hereinafter referred to collectively as "Executing Parties").

**B. Overview of PCA**

2. The proposed PCA is 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. The factors influencing the variability of power costs included in the proposal are primarily weather or market related. PSE will be allowed to file for rate increases to implement limited power supply cost increases related to new resources, discussed later.

3. **Sharing proposal:**

- **First Band (dead band):** \$20 million (+/-) annually, 100% of costs and benefits to Company.
- **Second Sharing Band:** \$20-\$40 million (+/-) annually, 50% of costs and benefits to Company; 50% of costs and benefits to Customers.

- **Third Sharing Band:** \$40-\$120 million (+/-) annually, 10% of costs and benefits to Company; 90% of costs and benefits to Customers.
- **Fourth Sharing Band:** Greater than \$120 million (+/-) annually, 5% of costs and benefits to Company; 95% of costs and benefits to Customers.
- **Overall Cap For Four Year Period July 1, 2002 through June 30, 2006:** As a separate limit, the Company's share of power costs/benefits will not exceed a \$40 million (+/-) cumulative net balance, as calculated per the sharing bands discussed above. If this cap is exceeded, sharing thereafter is adjusted to 99% of costs and benefits to Customers and 1% of costs and benefits to Company. The cap is removed at end of the fourth year (June 30, 2006), and any deferred balances associated with the cap are set for refund or collection at that time.
- **Deferral and Interest:** The customer's share of the power cost variability will be deferred as described below, and the balance will accrue monthly interest at the interest rate calculated in accordance with WAC 480-90-233(4). Amounts will be deferred consistent with recovery under the provisions of SFAS 71.

4. **Timing of surcharges or credits:**

- The sharing amounts will be accounted for, on an annual basis. The first 12 month period will be the period beginning July 1, 2002 and ending June 30, 2003. Subsequent PCA periods will be 12 month period beginning on July 1 of each year. The surcharging of deferrals can be triggered by the Company when the balance of the deferral account is approximately \$30 million. The Company shall make a filing to refund deferrals when the balance in the deferral account is a credit of \$30 million or more.
- To address financial needs and to provide Customers a price signal to reduce energy consumption, a surcharge can be triggered when the Company determines that, for any upcoming 12 month period, the projected increase in the deferral balance for increased power costs will exceed \$30 million. The surcharge will be implemented through a special filing subject to Commission approval detailing the events giving rise to the projected cost variance.
- 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. The Company will also provide the

Commission with a quarterly report of the deferral calculation in a form satisfactory to the Commission.

- Unless otherwise determined by the Commission, surcharges or credits will be collected or refunded, as the case may be, over a one year period. If for any reason the PCA shall cease to exist, any balances in the deferred accounts not previously reviewed will be reviewed and set for refund or surcharge to customers at that time.

**C. Elements of PCA**

5. **Power Cost Rate:** In order to focus on the component of the Company's rates to be adjusted by a PCA, it is necessary to distinguish between power costs and all other costs in general rates. This will single out the relative portion of the Company's rate to be adjusted by the proposed PCA and in the periodic "Power Cost Only" review. The purpose is for the PCA, and any Power Cost Only case, to measure the cost of power delivered to PSE's system, and to measure the change in this overall cost. The following table illustrates the proposed distinctions among costs in the Company's rates.

**Total Revenue Requirement Table**

<b>Total Rate</b>		
<b>Power Cost Rate<sup>1</sup></b>		<b>Non-power Costs</b>
<b>Variable Rate Component</b>	<b>Fixed Rate Component</b>	
<p><b>Fuel</b></p> <p>Other revenues and costs associated with fuel</p> <p>Purchase &amp; Interchange (purchase power contracts not to exceed general rate case or PCA resource case cost level)</p> <p>Sales to Others</p> <p>Wheeling costs</p> <p>Transmission income associated with specific lines</p> <p>Specific Production regulatory assets* amortization and return (7.30% net of tax) at current PCA rate year level</p> <p>Adjustment for availability of Colstrip</p>	<p>Following items to be recovered at the last general rate case or PCA resource case revenue levels:</p> <p>Production Plant and specific Transmission** Return on Ratebase (7.30% net of tax)</p> <p>Production Plant and specific Transmission Depreciation</p> <p>Production Plant and specific Transmission Property Taxes</p> <p>Production plant and specific Transmission O&amp;M</p> <p>Other Power Supply Expenses</p> <p>**Specific Transmission – Colstrip 1&amp;2 line, Colstrip 3&amp;4 line. Third AC, Northern Intertie,</p>	<p>Transmission (other than what has been included in PCA fixed rate component).</p> <p>Distribution</p> <p>All other operating accounts not included in the Power Cost Rate.</p>
<p>*Regulatory Assets – Tenaska, Encogen (Cabot Oil buy out), Bonneville</p>	<p>**Specific Transmission – Colstrip 1&amp;2 line, Colstrip 3&amp;4 line. Third AC, Northern</p>	

<sup>1</sup> References in table correspond to FERC accounts to be itemized in the Exhibits. For example, "Other Power Supply Expenses" corresponds to FERC Account 557.

Exchange Power	Intertie,	
----------------	-----------	--

6. **Adjustment for Availability of Colstrip:** A Colstrip adjustment will be measured against a weighted equivalent availability factor. If the actual availability factor (weighted by PSE ownership times unit capacity) for the four plants at Colstrip falls below a 70% equivalent availability factor a reduction will be made to the allowable revenue requirement for Colstrip. The calculation will be calculated by subtracting the actual weighted equivalent availability factor from 75%. This difference will be divided by 75% and the resulting percentage will be multiplied times the fixed costs (such fixed costs being more particularly described in Exhibit A) associated with Colstrip. The revenue requirement associated with this portion of these fixed costs will be removed from the allowable costs in the PCA.

7. **New Resources:** New resources with a term of less than or equal to two years will be included in the allowable PCA costs. The prudence of these resources will be determined in the Commission's review of the annual PCA report. New resources with a term greater than two years may be included in the PCA allowable cost at the lesser of the actual cost or the average embedded cost in the PCA (including transmission into PSE's Puget Sound system) as a bridge mechanism, until the then future costs of these new resources can be reviewed in a Power Cost Only Rate review.

8. **Power Cost Only Rate Review:** In addition to the yearly adjustment for power cost variances, there would be a periodic proceeding specific to power costs that would true up the Power Cost Rate to *all power costs* identified in the Power Cost Rate. The Company can also initiate a power cost only proceeding to add new resources to the Power Cost Rate. In either case, the Company would submit a Power Cost Only Rate filing proposing such change. This filing shall include testimony and exhibits that include the following:

- Current or updated least cost plan
- Description of the need for additional resources (as applicable)
- Evaluation of alternatives under various scenarios
- Adjustments to the Fixed Rate Component
- Adjustments to the Variable Rate Component
- A calculation of proforma production cost schedules that are consistent with this docket, including power supply and other adjustments impacting then current production costs.

9. If, during the first three (3) years after new rates have gone into effect (i.e., the three year period commencing July 1, 2002 and ending July 1, 2005) the Commission shall approve a cumulative increase to general rates in excess of 5%, and such cumulative increase in excess of 5% is the result of rate increases sought by the Company and approved by the Commission in one or more such Power Cost Only reviews, then within three (3) months of the date such cumulative rate increase in excess of 5% shall take effect, the Company shall file a general rate case.

10. Further, if at any time after July 1, 2005 the Company shall file for a Power Cost Only review, and such filing shall result in an increase to general rates then in effect, the Company shall, within three (3) months of the effective date of any rate increase resulting from such Power Cost Only review, file a general rate case. Not more than one general rate case filing in any 12 month period shall be required to comply with this requirement.

11. One objective of a new resource proceeding is to have the new Power Cost Rate in effect by the time the new resource would go into service. Upon receipt of such filing, hearings would be scheduled to review the appropriateness of adjusting the Power Cost Rate and/or adding new resource costs to the Power Cost Rate. These hearings would consider only power supply costs included within the Power Cost Rate. It is contemplated that this review would be completed within four months. Within 30 days following the four month review, the Commission would issue an order determining the appropriateness of all power costs to be included in the Power Cost Rate and the prudence of any new resource (with a term greater than two years) acquisition.

#### **D. PCA Mechanism (procedures)**

12. Exhibit A details PSE's presentation of the power costs, on a test year level (as defined in the revenue requirement settlement in Docket No. UE-011570) identified in the Total Revenue Requirement Table. The purpose of this exhibit is to calculate the Power Cost Baseline Rate which is defined as the sum of the Fixed Rate Components and Variable Rate Components divided by the test year delivered load (MWh). The remaining Executing Parties agree to PSE's presentation shown in Exhibit A and will verify in due course the accuracy of the specific numbers in that exhibit.

13. Exhibit B, which is based on the Company's presentation of test year costs and is subject to verification by the remaining Executing Parties as described above, is an explanation and example of a calculation used in the PCA to determine the amount of power cost that will be subject to the sharing mechanism. This exhibit calculates the amount subject to sharing by subtracting the Baseline Power Costs from the Allowed Power Costs (rate year). Baseline Power Costs are defined as the Power Cost Baseline Rate times actual delivered load in the PCA period. The allowed power costs include: return on fixed production and transmission ratebase, return on variable (regulatory asset) ratebase, other Fixed Rate Components and actual cost of variable rate components included in the specified FERC accounts. The allowed power costs are adjusted for:

- existing (Docket No. UE-921262) prudence adjustment of Tenaska and March Point Phase 2
- regulatory asset ratebase and amortization will be adjusted to the amounts to be included for the appropriate PCA period (Exhibit D)
- purchase power contracts will be adjusted to the amounts allowed in either the settlement Docket No. UE-011570 or the most recent Power Cost Rate Case (Exhibit E)
- Colstrip availability adjustment if applicable (Exhibit F)
- New resource pricing adjustment if applicable (Exhibit G)

14. Exhibit C is an example that demonstrates the sharing and application of the \$40 million cap.

15. Unless otherwise ordered by the Commission, changes in rates attributable to PCA adjustments for the Variable Rate Component shall be charged on a cents/kWh basis, and changes in rates attributable to adjustments to the Power Cost Rate as a result of a power cost only review shall be charged based upon the peak credit methodology utilized in computing the rate spread methodology in this proceeding. No party is deemed to have approved or accepted these methodologies for any other purpose or precedent. Wholesale customers will be allocated power costs and power revenues at the end of a PCA year in the same relationship as done in the rate allocation from this docket.

#### **E. Least-Cost Planning/Decoupling**

16. One of Puget Sound Energy's important responsibilities involves electric-resource portfolio development, a responsibility addressed in the Company's least cost plans prepared pursuant to WAC 480-100-238. This includes, among other things, assembling a mix of demand-and supply-side resources that promotes the societal benefits of reliable least cost electricity supplies. The parties agree that PSE's least-cost planning process provides an appropriate forum to address the evaluation of PSE's portfolio development, including consideration of rewards and/or penalties tied to PSE's overall long-term performance in portfolio development. The parties recommend that the Commission address these issues as soon as possible in Puget's least-cost planning process, pursuant to WAC 480-100-238, with opportunities for public comment prior to final determination.

17. Nothing in this settlement precludes any party from raising in an appropriate future Commission proceeding issues surrounding the decoupling of distribution fixed cost recovery from retail sales volumes. The parties have reached no consensus on what constitutes an "appropriate proceeding" for this purpose, and reserve the right to oppose any effort to raise such issues.



**F. Miscellaneous Provisions**

18. **Binding on Parties:** The Executing Parties agree to support the terms and conditions of this Agreement, as described above. The Executing Parties understand that this Agreement is subject to Commission approval.

19. **Integrated Terms of Settlement:** The Executing Parties have negotiated this Agreement as an integrated document. Accordingly, the Executing Parties agree to recommend that the Commission adopt this Agreement in its entirety.

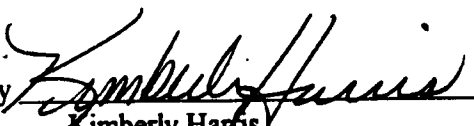
20. **Negotiated Agreement:** This Agreement represents a fully negotiated agreement. Each Executing Party has been afforded the opportunity, which it has exercised, to review the terms of the Agreement. Each Party has been afforded the opportunity, which it has exercised, to consult with legal counsel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

21. **Execution:** This Agreement may be executed by the Executing Parties in several counterparts, through original and/or facsimile signature, and as executed shall constitute one agreement.

DATED this 4th day of June, 2002.

**PUGET SOUND ENERGY, INC.**

**WASHINGTON UTILITIES AND  
TRANSPORTATION COMMISSION  
STAFF**

By   
Kimberly Harris  
Vice President of Regulatory Affairs

By \_\_\_\_\_  
Robert Cedarbaum  
Shannon Smith  
Assistant Attorneys General

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

**AT&T WIRELESS SERVICES, INC.**

By \_\_\_\_\_  
Simon fitch  
Assistant Attorney General  
Public Counsel Section Chief

By \_\_\_\_\_  
Its \_\_\_\_\_

F. **Miscellaneous Provisions**

18. **Binding on Parties:** The Executing Parties agree to support the terms and conditions of this Agreement, as described above. The Executing Parties understand that this Agreement is subject to Commission approval.

19. **Integrated Terms of Settlement:** The Executing Parties have negotiated this Agreement as an integrated document. Accordingly, the Executing Parties agree to recommend that the Commission adopt this Agreement in its entirety.

20. **Negotiated Agreement:** This Agreement represents a fully negotiated agreement. Each Executing Party has been afforded the opportunity, which it has exercised, to review the terms of the Agreement. Each 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 Agreement shall not be construed for or against any Executing Party based on the principle that ambiguities are construed against the drafter.

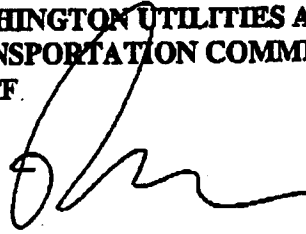
21. **Execution:** This Agreement may be executed by the Executing Parties in several counterparts, through original and/or facsimile signature, and as executed shall constitute one agreement.

DATED this 4th day of June, 2002.

**PUGET SOUND ENERGY, INC.**

By \_\_\_\_\_  
Kimberly Harris  
Vice President of Regulatory Affairs

**WASHINGTON UTILITIES AND  
TRANSPORTATION COMMISSION  
STAFF**

By \_\_\_\_\_  
  
Robert Cedarbaum  
Shannon Smith  
Assistant Attorneys General

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

By \_\_\_\_\_  
Simon ffitich  
Assistant Attorney General  
Public Counsel Section Chief

**AT&T WIRELESS SERVICES, INC.**

By \_\_\_\_\_  
Its \_\_\_\_\_

**F. Miscellaneous Provisions**

18. **Binding on Parties:** The Executing Parties agree to support the terms and conditions of this Agreement, as described above. The Executing Parties understand that this Agreement is subject to Commission approval.

19. **Integrated Terms of Settlement:** The Executing Parties have negotiated this Agreement as an integrated document. Accordingly, the Executing Parties agree to recommend that the Commission adopt this Agreement in its entirety.

20. **Negotiated Agreement:** This Agreement represents a fully negotiated agreement. Each Executing Party has been afforded the opportunity, which it has exercised, to review the terms of the Agreement. Each 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 Agreement shall not be construed for or against any Executing Party based on the principle that ambiguities are construed against the drafter.

21. **Execution:** This Agreement may be executed by the Executing Parties in several counterparts, through original and/or facsimile signature, and as executed shall constitute one agreement.

DATED this 4th day of June, 2002.

**PUGET SOUND ENERGY, INC.**

**WASHINGTON UTILITIES AND  
TRANSPORTATION COMMISSION  
STAFF**

By \_\_\_\_\_  
Kimberly Harris  
Vice President of Regulatory Affairs

By \_\_\_\_\_  
Robert Cedarbaum ✓  
Shannon Smith ✓  
Assistant Attorneys General

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

**AT&T WIRELESS SERVICES, INC.**

By \_\_\_\_\_ 6/6/02  
Simon Fitch ✓  
Assistant Attorney General  
Public Counsel Section Chief

By \_\_\_\_\_  
Its \_\_\_\_\_

06/04/02 TUE 13:09 FAX 425 560 8324

AT&T WIRELESS

JUN-04-2002 TUE 01:35 PM DAVIS WRIGHT TREMAINE

FAX NO. 5037785299

06/04/2002 12:58 FAX 425 4837388

PERKINS COPE BELLEVUE

**F. Miscellaneous Provisions**

**18. Binding on Parties:** The Executing Parties agree to support the terms and conditions of this Agreement, as described above. The Executing Parties understand that this Agreement is subject to Commission approval.

**19. Integrated Terms of Settlement:** The Executing Parties have negotiated this Agreement as an integrated document. Accordingly, the Executing Parties agree to recommend that the Commission adopt this Agreement in its entirety.

**20. Negotiated Agreement:** This Agreement represents a fully negotiated agreement. Each Executing Party has been afforded the opportunity, which it has exercised, to review the terms of the Agreement. Each 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 Agreement shall not be construed for or against any Executing Party based on the principle that ambiguities are construed against the drafter.

**21. Execution:** This Agreement may be executed by the Executing Parties in several counterparts, through original and/or facsimile signature, and as executed shall constitute one agreement.

DATED this 4th day of June, 2002.

**FUGET SOUND ENERGY, INC.**

**WASHINGTON UTILITIES AND  
TRANSPORTATION COMMISSION  
STAFF**

By \_\_\_\_\_  
Kimberly Harris  
Vice President of Regulatory Affairs

By \_\_\_\_\_  
Robert Cedarbaum  
Shannon Smith  
Assistant Attorneys General

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

**AT&T WIRELESS SERVICES, INC.**

By \_\_\_\_\_  
Simon Birch  
Assistant Attorney General  
Public Counsel Section Chief

By Chris Calvey C.P.M.  
its Community Manager

**COGENERATION COALITION OF  
WASHINGTON**

**KROGER CO.**

By Donald Brookhyser  
Donald Brookhyser  
Attorney for Cogeneration  
Coalition of Washington

By \_\_\_\_\_  
Michael L. Kurtz ✓  
Attorney for Kroger Co.

**NW ENERGY COALITION and  
NATURAL RESOURCES DEFENSE  
COUNCIL**

By \_\_\_\_\_  
Danielle Dixon  
Policy Associate, NW Energy Coalition

MICROSOFT CORPORATION

AT&T WIRELESS SERVICES, INC.

By \_\_\_\_\_  
Its \_\_\_\_\_

By \_\_\_\_\_  
Its \_\_\_\_\_

COGENERATION COALITION OF WASHINGTON

KROGER CO.

By \_\_\_\_\_  
Donald Brookhyser  
Attorney for Cogeneration  
Coalition of Washington

By *Michael L. Kurtz*  
Michael L. Kurtz  
Attorney for Kroger Co.

NW ENERGY COALITION and  
NATURAL RESOURCES DEFENSE  
COUNCIL

By \_\_\_\_\_  
Danielle Dixon  
Policy Associate, NW Energy Coalition

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

**AT&T WIRELESS SERVICES, INC.**

By \_\_\_\_\_  
Simon Fitch  
Assistant Attorney General  
Public Counsel Section Chief

By \_\_\_\_\_  
Its \_\_\_\_\_


**COGENERATION COALITION OF  
WASHINGTON**

**KROGER CO.**

By \_\_\_\_\_  
Donald Brookhyser  
Attorney for Cogeneration  
Coalition of Washington

By \_\_\_\_\_  
Michael L. Kurtz  
Attorney for Kroger Co.

**NW ENERGY COALITION and  
NATURAL RESOURCES DEFENSE  
COUNCIL**

By   
Danielle Dixon  
Policy Associate, NW Energy Coalition

**Exhibit A-1 Power Cost Rate**

Row		Test Year		
3	Regulatory Assets (Variable)	\$	284,728,294	
4	Transmission Rate Base (Fixed)		124,643,364	
5	Production Rate Base (Fixed)		493,777,165	
6		\$	903,148,823	
7	Net of tax rate of return		7.30%	
8				
9				
			<b>Test Yr</b>	<b>Rate Year</b>
			<b>\$/MWh</b>	
10	Regulatory Asset Recovery	\$	31,977,178	\$ 1.677 (c)
11	Fixed Asset Recovery-Prod Factored		54,142,951	\$ 2.840 (a)
12	Fixed Asset Recovery Other		15,310,432	\$ 0.803 (a)
13	501-Steam Fuel		32,511,186	\$ 1.705 (c)
14	555-Purchased power		526,980,333	\$ 27.643 (c)
15	557-Other Power Exp		11,499,089	\$ 0.603 (a)
16	547-Fuel		61,173,325	\$ 3.209 (c)
17	565-Wheeling		41,435,360	\$ 2.174 (c)
18	Variable Transmission Income		(6,510,985)	\$ (0.342) (c)
19	Hydro and Other Pwr.		51,597,583	\$ 2.707 (a)
20	447-Sales to Others		(37,525,193)	\$ (1.968) (c)
	456-Subaccounts 00012 &			
21	00018 and 00035 & 00036		1,077,379	\$ 0.057 (c)
22	Transmission Exp - 500KV		342,495	\$ 0.018 (a)
23	Depreciation-Production		36,265,740	\$ 1.902 (a)
24	Depreciation-Transmission		4,851,654	\$ 0.254 (a)
25	Property Taxes-Production		8,343,174	\$ 0.438 (a)
26	Property Taxes-Transmission		4,441,860	\$ 0.233 (a)
27	Subtotal & Baseline Rate	\$	837,913,560	\$ 43.953 (b)
28	Revenue Sensitive Items		0.9552337	
29		\$	877,181,741	8,343,174
30	Test Year Load (MWH's)		19,063,867	<-- includes Firm Wholesale
31			<u>Before Rev. Sensitive Items</u>	<u>After Rev. Sensitive Items</u>
	Power Cost in Rates with			
	Revenue Sensitive Items (the			
	adjusted baseline		46.013	
32	sum of (a) = Fixed Rate Component		9.798	10.257
33	(b) = Power Cost Rate		43.953	46.013
34	sum of (c) = Variable Power Rate		34.155	35.756
35	Component			
36				
37				
38	* Regulatory Assets are Tenaska, Encogen Fuel Buyout and BEP			
39				
40				
41				
42				
43				



**Exhibit A-2 Transmission Costs**

Row	Date	DR (CR) Accumulated Deferred Income Income Tax			
		Balance			
8		<b>Colstrip Related Transmission Assets</b>			
9					
10	06/30/2001		(15,759,774)		
11		No deferred income taxes associated with the 3rd AC Intertie, Northern Intertie and BPA Transmission Assets.			
12					
13					
14		<b>Test Period Property Taxes on transmission Related Assets:</b>			
15		<u>Amount</u>			
16		\$864,624			
17		1,622,875			
18					
19		1,826,626			
20		<u>127,735</u>			
21		\$4,441,860			
22					
23		41,435,360			
24					
25		<b>Transmission Plant</b>			
26					
27		<b>Plant</b>			
28		AMA 6/30/01	Accum. Dep.	Depreciation Exp.	
29		E351 Easements	685,927	264,280	17,011
30		E353 Station Equipment	1,231,131	682,186	34,964
31		E354 Towers & Fixtures	14,474,343	5,917,036	374,885
32		E355 Poles & Fixtures	49,007	39,834	774
33		E356 OH Conductors & devices	13,158,153	5,749,080	369,744
34		E359 Roads & Trails	<u>113,968</u>	<u>43,839</u>	<u>2,872</u>
35		COLSTRIP 1&2 TRANSMISSION	29,712,529	12,696,255	800,250
36					
37		<b>TRANS - COLSTRIP 3 &amp; 4</b>			
38		E351 Easements	1,071,124	396,585	27,314
39		E352 Structures & Improvements	478,326	188,636	11,719
40		E353 Station Equipment	17,687,015	6,706,154	578,365
41		E354 Towers & Fixtures	20,422,516	8,020,387	541,197
42		E355 Poles & Fixtures	122,619	58,220	3,298
43		E356 OH Conductors & Devices	20,015,734	8,474,189	572,450
44		E359 Roads & Trails	<u>341,015</u>	<u>127,820</u>	<u>8,730</u>
45		COLSTRIP 3&4 TRANSMISSION	60,138,349	23,971,991	1,743,073
46					
47		<b>TRANS - 3RD NW-SW INTERTIE</b>			
48		E352 Structures & Improvements	1,276,264	183,547	22,845
49		E353 Station Equipment	31,157,075	5,529,150	716,613
50		E354 Towers & Fixtures	22,781,417	3,276,322	430,569
51		E355 Poles & Fixtures	204,200	19,787	5,268
52		E356 OH Conductors & devices	23,458,461	4,528,227	609,920
53		E359 Roads & Trails	<u>59,215</u>	<u>4,141</u>	<u>628</u>
54		TOTAL 3RD NW-SW INTERTIE	78,936,632	13,541,174	1,785,843
55					
56		<b>TRANS - NORTHERN INTERTIE</b>			
57		E351 Easements - Whatcom		-	-
58		E354 Towers & Fixtures-Whatcom	5,744,097	533,604	106,840
59		E355 Poles & Fixtures-Whatcom	11,219	1,702	289
60		E356 OH Conductors & Devices-Whatcom	7,460,099	904,353	193,963
61		E355 Poles & Fixtures-Skagit	3,398,685	416,680	87,686
62		E356 OH Conductors & Devices-Skagit	<u>5,142,699</u>	<u>501,239</u>	<u>133,710</u>
63		TOTAL NORTHERN INTERTIE	21,756,799	2,357,577	522,488
64					
65		Total Transmission	190,544,309	52,566,998	4,851,654
66		Less			
67		Accumulated Depreciation	52,566,998		
68		Deferred Taxes	<u>15,759,774</u>		
69		Transmission Ratebase	122,217,537		
		revised_A2			
		revised accumulated depreciation	50,141,171		
			124,643,364		

**Exhibit A-3 Colstrip Fixed Costs**

Row

A-3 Page 1

	Revenue Requirement for Colstrip		
4	Plant	650,197,157	
5	Accumulated Depreciation	(320,264,159)	
6	Deferred Taxes	(93,834,221)	
7	Net Plant	<u>236,298,777</u>	
8	Rate of Return (net of Tax)	<u>7.30%</u>	
9	Revenue Requirement after tax	17,249,811	
10	Plant Revenue Requirement	26,538,170	(Adjusted for Federal Tax)
11	Expenses	<u>52,329,884</u>	
12	Total Revenue Requirement	<u>78,868,054</u>	(before revenue sensitive items)

**Support for Revenue Requirement - Ratebase**

FERC	DESCRIPTION	30-Jun-00	30-Jun-01	13 MONTH AMA	ANNUITY RATE	ANNUALIZED DEPRECIATION	ACUMM. DEPR. 06/30/2001
	<b>COLSTRIP #1</b>						
E311	Structures & Improvements	6,931,939	7,097,390	7,021,558	3.03%	212,753	4,519,382
E312	Boiler Plant Equipment	46,965,650	48,224,007	47,159,778	3.12%	1,471,385	30,962,573
E314	Turbo Generating Units	12,437,937	12,437,937	12,437,937	3.29%	409,208	8,005,683
E315	Accessory Electric Equip.	7,042,053	7,043,604	7,042,893	2.71%	190,862	4,440,864
E316	Misc. Power Plant Equip.	365,117	426,565	398,402	3.87%	15,418	215,987
	<b>TOTAL</b>	<b>73,742,696</b>	<b>75,229,503</b>	<b>74,060,568</b>	<b>3.11%</b>	<b>2,299,626</b>	<b>48,144,488</b>
	<b>COLSTRIP #2</b>						
E311	Structures & Improvements	5,317,757	5,573,840	5,458,360	3.06%	166,965	3,343,898
E312	Boiler Plant Equipment	39,821,935	40,460,296	40,167,714	3.05%	1,225,115	28,457,593
E314	Turbo Generating Units	12,178,755	12,519,462	12,363,305	3.26%	403,044	7,691,610
E315	Accessory Electric Equip.	4,536,518	4,592,474	4,566,828	2.69%	122,848	2,797,275
E316	Misc. Power Plant Equip.	365,931	427,379	399,215	3.61%	14,412	217,888
	<b>TOTAL</b>	<b>62,220,895</b>	<b>63,573,251</b>	<b>62,953,422</b>	<b>3.07%</b>	<b>1,932,384</b>	<b>40,508,284</b>
	<b>COLSTRIP 1 &amp; 2 COMMON</b>						
E311	Structures & Improvements	30,345,256	31,983,349	31,232,556	3.16%	988,949	18,788,553
E312	Boiler Plant Equipment	8,623,422	8,679,337	8,653,709	3.18%	275,188	5,533,214
E314	Turbo Generating Units	3,918,858	3,918,858	3,918,858	3.31%	129,714	2,382,313
E315	Accessory Electric Equip.	2,377,984	2,420,179	2,400,840	3.07%	73,706	1,334,875
E316	Misc. Power Plant Equip.	6,235,545	6,561,728	6,412,227	3.82%	244,947	3,136,065
	<b>TOTAL</b>	<b>51,501,064</b>	<b>53,563,451</b>	<b>52,618,190</b>	<b>3.25%</b>	<b>1,710,504</b>	<b>31,175,020</b>
	<b>COLSTRIP 3</b>						
E311	Structures & Improvements	28,829,642	28,882,948	28,858,516	2.45%	707,034	14,566,340
E312	Boiler Plant Equipment	113,898,277	115,756,485	113,618,072	2.68%	3,044,964	57,262,237
E314	Turbo Generating Units	32,936,825	33,180,681	33,068,914	2.97%	982,147	14,166,239
E315	Accessory Electric Equip.	6,401,615	6,401,615	6,401,615	2.47%	158,120	2,874,151
E316	Misc. Power Plant Equip.	454,762	480,140	468,508	2.86%	13,399	210,034
	<b>TOTAL</b>	<b>182,521,121</b>	<b>184,701,869</b>	<b>182,415,625</b>	<b>2.69%</b>	<b>4,905,664</b>	<b>89,079,001</b>
	<b>COLSTRIP 4</b>						
E311	Structures & Improvements	26,542,394	26,595,701	26,571,269	2.54%	674,910	11,552,369
E312	Boiler Plant Equipment	99,709,843	100,508,440	100,142,416	2.75%	2,753,916	43,898,288
E314	Turbo Generating Units	27,895,777	28,602,598	28,278,838	2.94%	831,392	10,813,318
E315	Accessory Electric Equip.	5,589,362	5,596,707	5,593,341	2.52%	140,952	2,183,849
E316	Misc. Power Plant Equip.	650,784	676,163	664,531	2.79%	18,540	277,867
	<b>TOTAL</b>	<b>160,388,160</b>	<b>161,979,809</b>	<b>161,250,195</b>	<b>2.74%</b>	<b>4,419,710</b>	<b>68,705,690</b>
	<b>COLSTRIP 3 &amp; 4 COMMON</b>						
E311	Structures & Improvements	71,951,771	72,034,845	71,996,769	2.33%	1,677,525	35,209,226
E312	Boiler Plant Equipment	20,855,440	20,915,298	20,887,863	2.48%	518,019	10,585,040
E314	Turbo Generating Units	274,553	274,553	274,553	2.62%	7,193	125,852
E315	Accessory Electric Equip.	7,706,935	7,748,971	7,729,705	2.31%	178,556	3,422,068
E316	Misc. Power Plant Equip.	4,861,282	5,098,460	4,989,753	2.79%	139,214	2,083,870
	<b>TOTAL</b>	<b>105,649,981</b>	<b>106,072,127</b>	<b>105,878,643</b>	<b>2.38%</b>	<b>2,520,507</b>	<b>51,426,057</b>
	<b>COLSTRIP 1-4 COMMON</b>						
E316	Misc. Power Plant Equip.	253,865	253,865	253,865	2.46%	6,245	123,888
	<b>TOTAL</b>	<b>253,865</b>	<b>253,865</b>	<b>253,865</b>	<b>2.46%</b>	<b>6,245</b>	<b>123,888</b>
	<b>COLSTRIP COMMON FERC ADJ.</b>	<b>8,316,981</b>		<b>8,316,981</b>			
	<b>COLSTRIP DEF DEPR FERC ADJ.</b>	<b>2,449,668</b>		<b>2,449,668</b>			
	<b>Total Plant and Acc. Deprec.</b>	<b>647,044,432</b>		<b>650,197,157</b>		<b>17,794,840</b>	<b>329,162,409</b>

AMA Adj. (8,898,250)  
AMA Accum Depr 320,264,159

70	Support for Revenue Requirement - Expenses		Amount before
71			Prod. Adj.
72	Order	Description	
73	50004011	1&2 Sup & Eng	76,885
74	50005011	3&4 Sup & Eng	108,581
75	50204001	1&2 Steam Exp	1,217,034
76	50205001	3&4 Steam Exp	624,831
77	50504001	1&2 Elec Exp	(208,933)
78	50505001	3&4 Elec Exp	(223,913)
79	50604001	1&2 Misc Exp	3,320,269
80	50605001	3&4 Misc Exp	2,515,968
81	50605002	3&4 Steam	(2,399)
82	50704001	1&2 Rents	95,991
83	50705001	3&4 Rents	131,692
84	51004001	1&2 Maint Supv	669,151
85	51005001	3&4 Maint Supv	539,405
86	51104001	1&2 Maint of Struct	405,072
87	51105001	3&4 Maint of Struct	373,938
88	51204001	1&2 Maint of Boiler	4,902,128
89	51205001	3&4 Maint of Boiler	5,967,278
90	51304001	1&2 Maint of E Plant	(178,069)
91	51305001	3&4 Maint of E Plant	705,533
92	51404001	1&2 Maint of Misc	4,578,888
93	51405001	3&4 Maint of Misc	1,159,196
94		Property Taxes-Montana	6,027,509
95		Electric Energy Tax	1,729,406
96	403xxxx	Depreciation	17,794,640
97			<u>\$52,329,884</u>

**Exhibit A-4 Production Adjustment UE-011570**

**PAGE 2.21**

**PUGET SOUND ENERGY-ELECTRIC  
PRODUCTION ADJUSTMENT  
FOR THE TWELVE MONTHS ENDED JUNE 30, 2001  
GENERAL RATE INCREASE**

LINE NO.	DESCRIPTION	PRO FORMA PRODUCTION AMOUNT	2.84%	FIT 35%
1	PRODUCTION WAGE INCREASE			
2	PURCHASED POWER	0	0	0
3	OTHER POWER SUPPLY	0	0	0
4	TOTAL PRODUCTION WAGE INCREASE	0	0	0
5				
6	PAYROLL OVERHEADS	783,939	(22,264)	7,792
7	PROPERTY INSURANCE	1,026,555	(29,154)	10,204
8	TOTAL A&G	1,810,494	(51,418)	17,996
9				
10	DEPRECIATION PRODUCTION PROPERTY			
11	DEPRECIATION / AMORTIZATION	37,325,792	(1,060,052)	263,024
12	PURCHASED POWER	3,526,620	(100,156)	35,055
13	FUEL	0	0	0
14	TOTAL	40,852,412	(1,160,209)	298,079
15				
16	TAXES OTHER-PRODUCTION PROPERTY			
17	PROPERTY TAXES - WASHINGTON	3,041,963	(86,392)	30,237
18	PROPERTY TAXES - MONTANA	6,027,509	(171,181)	59,913
19	ELECTRIC ENERGY TAX	1,729,406	(49,115)	17,190
20	PAYROLL TAXES	630,032	(17,893)	6,263
21	TOTAL TAXES OTHER	11,428,910	(324,581)	113,603
22				
23	INCREASE(DECREASE) INCOME		1,536,208	
24	INCREASE(DECREASE) FIT			429,678
25	INCREASE(DECREASE) NOI			1,106,530
26				
27	RATE BASE:			
28	PRODUCTION PROPERTY	1,065,115,283		
29	COLSTRIP COMMON FERC ADJ.	8,316,981		
30	COLSTRIP DEF DEPR FERC ADJ.	2,449,668		
31	ENCOGEN ACQUISITION ADJ.	60,574,557		
32	BPA POWER EXCHANGE INVESTMENT	51,135,941	sum of L32 thru	293,050,941
33	TENASKA REGULATORY ASSET	229,424,000	L34	284,728,294
34	CABOT OIL REGULATORY ASSET	12,491,000		
35	LESS ACCUM. DEPRECIATION	(519,770,787)		
36	LESS ACCUM. AMORTIZATION	(3,186,245)		
37	NET PRODUCTION PROPERTY	906,550,398		
38				
39	DEDUCT:			
40	LIBR. DEPREC. PRE 1981 (EOP)	(5,250,238)		
41	LIBR. DEPREC. POST 1980 (EOP)	(94,132,216)		
42	OTHER DEF. TAXES (EOP)	(17,930,541)		
43	ADJUSTMENT TO RATE BASE	789,237,403	(22,414,342)	766,823,061
	Plus Snoqualmie CWIP			482,094,767
				11,682,398
				493,777,165

**Exhibit A-5 Power Costs UE-011570**

**PUGET SOUND ENERGY-ELECTRIC  
POWER COSTS  
FOR THE TWELVE MONTHS ENDED JUNE 30, 2001  
GENERAL RATE INCREASE**

LINE NO.	DESCRIPTION	ACTUAL	PROFORMA	INCREASE (DECREASE)
1	PRODUCTION EXPENSES:			
2	FUEL	\$ 297,843,394	\$ 93,684,510	\$ (204,158,884)
3	PURCHASED AND INTERCHANGED	2,226,570,459	534,528,072	(1,692,042,387)
4	WHEELING	31,116,222	41,435,360	10,319,138
5	OTHER POWER SUPPLY EXPENSES	46,736,543	51,597,585	4,861,042
6	TRANS. EXP. INCL. 500KV O&M	352,506	342,495	(10,011)
7	SALES FOR RESALE	(1,766,314,721)	(37,525,193)	1,728,789,528
8	PURCHASES/SALES OF NON-CORE GAS	(22,281,093)	1,077,379	23,358,472
9	WHEELING FOR OTHERS	(7,762,159)	(10,902,262)	(3,140,103)
10	SUBTOTAL	\$ 806,261,151	\$ 674,237,946	\$ (132,023,205)
11				
12	LESS: SALES FOR RESALE	1,766,314,721	37,525,193	(1,728,789,528)
13	LESS: WHEELING FOR OTHERS	7,762,159	10,902,262	3,140,103
14	SCH. 94 - RES./FARM CREDIT	(46,773,115)	-	46,773,115
15	TOTAL	\$ 2,533,564,916	\$ 722,665,401	\$ (1,810,899,515)
16	TRANS. EXP. INCL. 500KV O&M	(352,506)		
17	PURCHASES/SALES OF NON-CORE GAS	22,281,093		
18	POWER COSTS PER G/L	\$ 2,555,493,503		
19	INCREASE(DECREASE) INCOME			\$ 1,810,899,515
20				
21	INCREASE(DECREASE) FIT @	35%		633,814,830
22	INCREASE(DECREASE) NOI			<b>\$ 1,177,084,685</b>

**Exhibit B: Power Costs Subject to PCA Sharing**

Example  
Jul 02 - Jun 03

Row	Explanation or source	Amount	Amount	Amount	Amount	Amount	Amount	Amount	Amount
4									
5	Return on Fixed RB		\$ 71,035,988						
6	Other Fixed Costs		120,513,555						
7	Subtotal Fixed Costs		\$ 191,549,544						
8	Total Variable Component Actual								
9	Steam Oper. Fuel	501	illustrative est.	\$ 33,461,494					
10	Other Pwr Gen Fuel	547	illustrative est.	55,009,484					
11	Other Elec Revenues	45600012, 18	illustrative est.	(165,000)					
12	Purchase Power	555	illustrative est.	538,456,725					
13	Sales to Other Util	447	illustrative est.	(35,448,055)					
14	Wheeling	565	illustrative est.	43,486,800					
15	Transmission Revenue	45600017	illustrative est.	(5,000,000)					
16	Regulatory Assets		illustrative est.	32,611,879					
17									
18	SUBTOTAL before Adjustments		642,456.32	\$ 854,272,871					
19									
20	Adjustments:								
21	Prudence from UE-921262		illustrative est.	\$ (2,260,152)					
22	Contract price adjustment		illustrative est.	(1,094,429)					
23	Colstrip availability adjustment		illustrative est.	(5,812,478)					
24	New resource pricing adjustment		illustrative est.	(388,500)					
25									
26	Subtotal Adjustments			\$ (9,555,559)					
27	Total allowable cost			\$ 844,717,312					
28									
29	PCA period delivered load		est. actual	19,110,518					
30	Baseline Power Cost			\$ 839,964,611					
31				\$43,853					
32									
33	Imbalance for Sharing			\$ 4,752,701					
34	positive is potential customer surcharge, negative is potential customer credit								
35									
36	Company's Share	band limit +/-							
37	1st Band - deadband	\$ 20,000,000	100%	4,752,701	\$ 4,752,701				
38	2nd Band - next	\$ 20,000,000	50%	-	-				
39	3rd Band - next	\$ 80,000,000	10%	-	-				
40	4th Band greater than	\$120,000,000	5%	-	-				
41	Subtotal Company Share before Cap			4,752,701	\$ 4,752,701				
42									
43	Customer Share (deferral account)			\$ -					

### Exhibit C - Application of \$40 million Cap

**Overall Cap For Four Year Period:** As a separate limit, the Company's share of power costs/benefits will not exceed a \$40 million (+/-) cumulative net balance, as calculated per the sharing bands discussed in the settlement terms for the PCA. If this cap is exceeded, sharing thereafter is adjusted to 99% of costs and benefits to Customer and 1% of costs and benefits to Company. The cap is removed at end of the fourth year, and any remaining deferred balances associated with the cap are set for refund or collection at that time.

#### Example: 1 First year per draft Exhibit examples; next 3 years high power costs

\$ In Millions

Row	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Imbalance for Sharing Ex. B line 33	Customer Annual Share = "Deferral" Ex. B line 43	Customer Annual Share over Cap at 99%	End Period Customer Deferral Balance	Company Annual Share Ex. B line 41	Potential transfer (to) / from customer	Company share over Cap at 1%	End Period Company Shares	Company Accum Share w/o Cap	Accum. Amount Over Cap	Annual Change in Amount over Cap
13	PCA Yr #1 \$ (5.83)	\$ -	\$ -	\$ -	\$ (5.83)	\$ -	\$ -	\$ (5.83)	\$ (5.83)	\$ -	\$ -
14	PCA Yr #2 \$ 30.00	\$ 5.00	\$ -	\$ 5.00	\$ 25.00	\$ -	\$ -	\$ 19.17	\$ 19.17	\$ -	\$ -
15	PCA Yr #3 \$ 30.00	\$ 5.00	\$ 4.13	\$ 14.13	\$ 25.00	\$ (4.17)	\$ 0.04	\$ 40.04	\$ 44.17	\$ 4.17	\$ 4.17
16	PCA Yr #4 \$ 30.00	\$ 5.00	\$ 24.75	\$ 43.88	\$ 25.00	\$ (25.00)	\$ 0.25	\$ 40.29	\$ 69.17	\$ 29.17	\$ 25.00
17	Check \$ 84.2	OK	\$ -	\$ 43.9	\$ -	\$ -	\$ -	\$ 40.3	\$ -	\$ -	\$ -

### Exhibit C - Application of \$40 million Cap

Overall Cap For Four Year Period: As a separate limit, the Company's share of power costs/benefits will not exceed a \$40 million (+/-) cumulative net balance, as calculated per the sharing bands discussed in the settlement terms for the PCA. If this cap is exceeded, sharing thereafter is adjusted to 99% of costs and benefits to Customer and 1% of costs and benefits to Company. The cap is removed at end of the fourth year, and any remaining deferred balances associated with the cap are set for refund or collection at that time.

#### Example: 2 Four year cost scenario discussed at May 23rd PCA Collaborative

Row	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Imbalance for Sharing Ex. B line 33	Customer Annual Share = "Deferral" Ex. B line 43	Customer Annual Share over Cap at 99%	End Period Customer Deferral Balance	Company Annual Share Ex. B line 41	Potential transfer (to) / from customer	Company share over Cap at 1%	End Period Company Share	Company Accum Share w/o Cap	Accum. Amount Over Cap	Annual Change in Amount over Cap
26	PCA Yr #1 \$	5.0 \$	- \$	5.0 \$	25.0 \$	- \$	- \$	25.0 \$	25.0 \$	- \$	- \$
27	PCA Yr #2 \$	- \$	- \$	5.0 \$	- \$	- \$	- \$	25.0 \$	25.0 \$	- \$	- \$
28	PCA Yr #3 \$	(100.0) \$	- \$	(59.0) \$	(36.0) \$	- \$	- \$	(11.0) \$	(11.0) \$	- \$	- \$
29	PCA Yr #4 \$	36.0 \$	- \$	(51.0) \$	28.0 \$	- \$	- \$	17.0 \$	17.0 \$	- \$	- \$
30	Check \$	(34.0) OK		(51.0) \$				\$			



### Exhibit C - Application of \$40 million Cap

**Overall Cap For Four Year Period:** As a separate limit, the Company's share of power costs/benefits will not exceed a \$40 million (+/-) cumulative net balance, as calculated per the sharing bands discussed in the settlement terms for the PCA. If this cap is exceeded, sharing thereafter is adjusted to 99% of costs and benefits to Customer and 1% of costs and benefits to Company. The cap is removed at end of the fourth year, and any remaining deferred balances associated with the cap are set for refund or collection at that time.

**Example: 3** Three high power cost years followed by very low power cost year.

\$ In Millions

Row	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Inbalance for Sharing Ex. B line 33	Customer Annual Share = "Deferral" Ex. B line 43	Customer Annual Share over Cap at 99%	End Period Customer Deferral Balance	Company Annual Share Ex. B line 41	Potential transfer (to) / from customer	Company share over Cap at 1%	End Period Company Share	Company Accum Share w/o Cap	Accum. Amount Over Cap	Annual Change in Amount over Cap
39											
40											
41											
42	PCA Yr #1 \$ 30.0	\$ 5.0	\$ -	\$ 5.0	\$ 25.0	\$ -	\$ -	\$ 25.0	\$ 25.0	\$ -	\$ -
43	PCA Yr #2 \$ 100.0	\$ 64.0	\$ 20.8	\$ 89.8	\$ 36.0	\$ (21.0)	\$ 0.2	\$ 40.2	\$ 61.0	\$ 21.0	\$ 21.0
44	PCA Yr #3 \$ 36.0	\$ 8.0	\$ 27.7	\$ 125.5	\$ 28.0	\$ (28.0)	\$ 0.3	\$ 40.5	\$ 89.0	\$ 49.0	\$ 28.0
45	PCA Yr #4 \$ (100.0)	\$ (64.0)	\$ (35.6)	\$ 25.9	\$ (36.0)	\$ 36.0	\$ (0.4)	\$ 40.1	\$ 53.0	\$ 13.0	\$ (36.0)
46											
47	Check \$ 68.0	OK		\$ 25.9				\$ 40.1			
48											

### Exhibit C - Application of \$40 million Cap

**Overall Cap For Four Year Period:** As a separate limit, the Company's share of power costs/benefits will not exceed a \$40 million (+/-) cumulative net balance, as calculated per the sharing bands discussed in the settlement terms for the PCA. If this cap is exceeded, sharing thereafter is adjusted to 99% of costs and benefits to Customer and 1% of costs and benefits to Company. The cap is removed at end of the fourth year, and any remaining deferred balances associated with the cap are set for refund or collection at that time.

**Example: 4** Similar to example 3, but fortunes are reversed with 3 low cost years followed by a high cost year.

Row	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Imbalance for Sharing Ex. B line 33	Customer Annual Share = "Deferral" Ex. B line 43	Customer Annual Share over Cap at 99% Cap at 99%	End Period Customer Deferral Balance	Company Annual Share Ex. B line 41	Potential transfer (to) / from customer	Company share over Cap at 1%	End Period Company Share	Company Accum Share w/o Cap	Accum. Amount Over Cap	Annual Change in Amount over Cap
55	PCA Yr #1 \$ (30.0)	(5.0)	-	(5.0)	(25.0)	-	-	(25.0)	(25.0)	-	-
56	PCA Yr #2 \$ (100.0)	(64.0)	(20.8)	(89.8)	(36.0)	21.0	(0.2)	(40.2)	(61.0)	(21.0)	(21.0)
57	PCA Yr #3 \$ (36.0)	(8.0)	(27.7)	(125.5)	(28.0)	28.0	(0.3)	(40.5)	(88.0)	(49.0)	(28.0)
58	PCA Yr #4 \$ 100.0	64.0	35.8	(25.8)	36.0	(36.0)	0.4	(40.1)	(53.0)	(13.0)	36.0
60	Check \$ (66.0)	OK		(25.9)							
61											

Exhibit (Revised)

**Exhibit D: Regulatory Assets**

Row		Interest	Amort	Balance	PCA (Jul-Jun) Amortization	Ratebase (AMA)	Return 7.30%	35% Pre Tax Return
4	Cabot Buyout							
5								
6	2000 \$	12,588,000	(312,000)	12,985,000				
7	2001 \$	-	(741,000)	12,964,000				
8	2002 \$	-	(1,070,000)	12,625,000	(1,070,000)	12,491,033	\$ 911,845	\$ 1,402,839
9	2003 \$	-	(1,409,000)	11,216,000	(1,588,500)	11,170,908	\$ 815,476	\$ 1,254,579
10	2004 \$	-	(1,768,000)	9,448,000	(1,965,500)	9,398,408	\$ 686,084	\$ 1,055,514
11	2005 \$	-	(2,163,000)	7,285,000	(2,388,500)	7,228,408	\$ 527,674	\$ 811,806
12	2006 \$	-	(2,614,000)	4,671,000				
13								
14	Tenaska							
15	1998 \$	215,000,000	(1,952,000)	221,802,000				
16	1999 \$	-	(3,863,000)	226,734,000				
17	2000 \$	-	(5,463,000)	230,120,000				
18	2001 \$	-	(7,382,000)	231,576,000				
19	2002 \$	-	(9,494,000)	230,831,000	(9,494,000)	229,424,000	\$ 16,747,952	\$ 25,766,080
20	2003 \$	-	(11,924,000)	218,907,000	(13,334,000)	218,552,512	\$ 15,954,333	\$ 24,545,128
21	2004 \$	-	(14,744,000)	204,163,000	(16,326,000)	203,755,512	\$ 14,874,862	\$ 22,884,434
22	2005 \$	-	(17,908,000)	186,255,000	(19,261,500)	185,914,637	\$ 13,571,769	\$ 20,879,644
23	2006 \$	-	(20,615,000)	165,640,000				
24								
25	BEP							
26	2001		(3,526,620)	54,662,518	(3,526,620)	51,135,941	\$ 3,732,924	\$ 5,742,960
27	2002		(3,526,620)	51,135,898	(3,526,620)	47,609,278	\$ 3,475,477	\$ 5,346,888
28	2003		(3,526,620)	47,609,278	(3,526,620)	44,082,658	\$ 3,218,034	\$ 4,950,822
29	2004		(3,526,620)	44,082,658	(3,526,620)	40,556,038	\$ 2,960,591	\$ 4,554,755
30	2005		(3,526,620)	40,556,038	(3,526,620)	40,556,038	\$ 2,960,591	\$ 4,554,755
31	2006		(3,526,620)	37,029,418				
32								
33								
34								
35								
36								
37								
38								
39								

From	To	PCA#1	PCA#2	PCA#3	PCA#4	Amortization	AMA Ratebase	Return	Return Pre-tax
Jul-02	Jun-03					\$ (14,090,620)	\$ 293,050,974	\$ 21,392,721	\$ 32,911,879
Jul-03	Jun-04					\$ (18,449,120)	\$ 277,332,698	\$ 20,245,287	\$ 31,146,595
Jul-04	Jun-05					\$ (21,818,120)	\$ 257,246,578	\$ 18,779,000	\$ 28,890,770
Jul-05	Jun-06					\$ (25,176,620)	\$ 233,699,083	\$ 17,060,033	\$ 26,246,205

PCA  
Exhibit E - Contract Adjustments

Estimated costs from hypothetical PCA period

Row	CONTRACTS	Note	Limit - Rate or Total Cost per UE-011570	PCA Period			Adjust for Positive Differences
				Generation MWh	NUG Gen. MWh	NUG Displ. MWh	
6	Baker Replacement	Exchange					
9	BC Hydro Point Roberts	Rate Limit	\$ 67.00	21,432		\$ 1,436,000	\$ 0.00
10	BPA WNP-3 Exchange Power	Rate Limit	\$ 28.17	384,834		\$ 10,892,000	\$ 0.13
11	BPA WNP3 Return	Actual Cost					
12	BPA Snohomish Conservation	Rate Limit	\$ 51.35	92,170		\$ 4,733,000	\$ (0.00)
13	CSPE	N/A					
14	Mid-Columbia	Actual Cost					
15	Canadian Entitlement and CEA-EA	N/A					
16	MPC Firm Contract-Demand	Total Cost	\$ 29,382,000			\$ 29,732,000	\$ 350,000
17	MPC Firm Contract-Energy	Actual Cost					
18	PPL Contract 15 Yr	Actual Cost					
19	Supplemental Entitlement Cap	Actual Cost					
20	North Wasco	Rate Limit	\$ 62.85	39,031		\$ 2,500,000	\$ 1.20
21	WMP Contract 15 Yr	Actual Cost					
22	PG&E Exchange Storage Acctg.	through 12/31/02					
23	QF Shipp Hutch. Creek	Exchange					
24	QF Koma Kuisan Hydro	Rate Limit	\$ 30.04	1,731		\$ 52,000	\$ 30.04
25	QF March Point Copen 1 Winter	Rate Limit	\$ 74.87	32,692		\$ 2,448,000	\$ 74.88
26	QF March Point Copen 1 Summer	NUG Rate Limit	\$ 61.01	436,000	436,000	\$ 26,639,600	\$ 0.01
27	QF March Point Copen 2 Winter	NUG Rate Limit	\$ 43.70	181,000	100,000	\$ 12,279,700	\$ 0.09
28	QF March Point Copen 2 Summer	NUG Rate Limit	\$ 66.00	330,000		\$ 22,011,000	\$ 0.70
29	QF Port Townsend Hydro	NUG Rate Limit	\$ 55.30	232,000	100,000	\$ 12,829,600	\$ 55.30
30	QF PERC Puyallup	Rate Limit	\$ 28.21	2,694		\$ 76,000	\$ 28.21
31	QF Spokane MSW	Actual Cost					
32	QF Sumas Winter	Rate Limit	\$ 87.54	141,552		\$ 12,397,000	\$ 87.59
33	QF Sumas Summer	Rate Limit	\$ 81.84	663,000	663,000	\$ 54,631,200	\$ 82.40
34	QF Sybilowicz	NUG Rate Limit	\$ 59.20	461,000	381,000	\$ 27,291,200	\$ 59.20
35	QF Tenasta (excl. Reg. Amort.)	Rate Limit	\$ 51.37	1,421		\$ 73,000	\$ 51.37
36	QF Twin Falls	NUG Rate Limit	\$ 31.84	1,958,028	1,858,028	\$ 62,068,488	\$ (0.14)
37	QF Weech Falls	Rate Limit	\$ 75.00	99,955		\$ 5,246,625	\$ (0.00)
38	Stookumchuck	Rate Limit	\$ 75.00	12,542		\$ 940,650	\$ (0.00)
39		Actual Cost					
40	TOTAL						\$ 1,094,429

Reverse sign and enter on Exhibit B line 22 \$ (1,094,429)

- Notes:
- 42 Exchange: No Adjustment. Either power for power exchange at zero cost or fixed control for power at zero cost.
  - 43 Rate Limit: Calculate actual rate for PCA period, compare with contract rate assumed in revenue requirements; multiply rate change (if positive) times contract generation.
  - 44 N/A: No Adjustment. Zero cost contracts.
  - 45 Actual Cost: No Adjustment. Either no rate specified in contract, or rate based upon DJ market index, or as agreed.
  - 46 Total Cost: Limit based upon total cost in rate year because contract escalation is in fixed demand charges.
  - 47 NUG Rate Limit: Calculate actual rate monthly assuming actual availability with no displacement; compare with average seasonal rate-year contract rate (also without displacement); multiply rate change (if positive) times total of actual contract generation + displacement.

**CONFIDENTIAL**  
**Exhibit F - Colstrip Availability Adjustment**

Row

**Part 1. Colstrip Equivalent Availability during PCA period -12 Month**

	<u>1&amp;2</u>	<u>3&amp;4</u>		
6				
7	PSE MW ->	307	370	PSE Wtd days
8	Jul-02	85.00%	85.00%	85.0% 31
9	Aug-02	85.00%	85.00%	85.0% 31
10	Sep-02	85.00%	85.00%	85.0% 30
11	Oct-02	85.00%	85.00%	85.0% 31
12	Nov-02	85.00%	85.00%	85.0% 30
13	Dec-02	85.00%	85.00%	85.0% 31
14	Jan-03	85.00%	85.00%	85.0% 31
15	Feb-03	85.00%	85.00%	85.0% 28
16	Mar-03	85.00%	0.00%	38.5% 31
17	Apr-03	85.00%	0.00%	38.5% 30
18	May-03	85.00%	0.00%	38.5% 31
19	Jun-03	85.00%	0.00%	38.5% 30

21 12 mo Average 85.00% 56.59% **69.47%**  
 22 Weighted by days in the month Weighted by Plant Capacity and days/month

**Part 2. Calculate annual availability penalty ratio**

26	Less than 70%	yes	yes, penalty assessed
27	Actual Ratio	69.47%	
28	Target Ratio	75.00%	per Collaborative agreement
29	Penalty	-5.53%	

32 Penalty Ratio = **-7.37%** = penalty  $\frac{-5.53\%}{75.00\%}$  divided by per Collaborative agreement

**Part 3. Calculate Annual Colstrip Fixed Cost Penalty**

38	Total Fixed Cost	\$ 78,868,054	from Exhibit A-3 (Colstrip Total Revenue Requirement)
40	Penalty Ratio =	-7.37%	
41	Penalty \$	<b>\$ (5,812,478)</b>	to Exhibit B line 23

**Exhibit F - Data Input Page**  
Availability data from Colstrip Operation Reports

ROW		1&2	3&4	days	
5	Jan-01	98.66%	88.73%	31	Actual data
6	Feb-01	86.24%	97.78%	28	
7	Mar-01	95.36%	72.76%	31	
8	Apr-01	91.56%	48.20%	30	
9	May-01	75.12%	69.74%	31	
10	Jun-01	52.30%	71.73%	30	
11	Jul-01	94.38%	93.44%	31	
12	Aug-01	91.42%	97.77%	31	
13	Sep-01	80.02%	93.18%	30	
14	Oct-01	98.70%	95.99%	31	
15	Nov-01	96.71%	90.40%	30	
16	Dec-01	90.64%	88.21%	31	
17	Jan-02	93.80%	47.87%	31	
18	Feb-02	91.01%	79.26%	28	
19	Mar-02	97.14%	88.04%	31	
20	Apr-02	94.44%	93.99%	30	
21	May-02	85.00%	85.00%	31	
22	Jun-02	85.00%	85.00%	30	
23	Jul-02	85.00%	85.00%	31	
24	Aug-02	85.00%	85.00%	31	
25	Sep-02	85.00%	85.00%	30	
26	Oct-02	85.00%	85.00%	31	
27	Nov-02	85.00%	85.00%	30	
28	Dec-02	85.00%	85.00%	31	
29	Jan-03	85.00%	85.00%	31	
30	Feb-03	85.00%	85.00%	28	
31	Mar-03	85.00%	0.00%	31	
32	Apr-03	85.00%	0.00%	30	
33	May-03	85.00%	0.00%	31	
34	Jun-03	85.00%	0.00%	30	
35	Jul-03			31	
36	Aug-03			31	
37	Sep-03			30	
38	Oct-03			31	
39	Nov-03			30	
40	Dec-03			31	
41	Jan-04			31	
42	Feb-04			29	
43	Mar-04			31	
44	Apr-04			30	
45	May-04			31	
46	Jun-04			30	
<hr/>					
59	Jul-05			31	
60	Aug-05			31	
61	Sep-05			30	
62	Oct-05			31	
63	Nov-05			30	
64	Dec-05			31	
65	Jan-06			31	
66	Feb-06			28	
67	Mar-06			31	
68	Apr-06			30	
69	May-06			31	
70	Jun-06			30	

Actual data

Example data

**Exhibit G - New Resource Adjustment**

Row  
3  
4  
5  
6  
7  
8  
9  
10  
11

**For New Resources with a Terms Longer than 2 Years**

<b>Name</b>	Sample new plant
<b>Description</b>	Combined cycle gas turbine
	In-service date January 2003

**PCA Period** July 2002 - June 2003

<b>13 Total Variable Component Actual</b>		
14	Steam Oper. Fuel	501 \$ -
15	Other Pwr Gen Fuel	547 33,000,000
16	Other Elec Revenues	45600012, 18 -
17	Purchase Power	555 -
18	Sales to Other Util	447 -
19	Wheeling	565 750,000
20	Transmission Revenue	45600017 -
21		\$ 33,750,000

22	PCA Period Generation	(MWh)	750,000
23			
24	Actual Variable Cost	(\$/MWh)	\$45.000
25	Compare with Baseline Rate		
26			
27	Baseline Power Cost Rate	(\$/MWh)	\$44.482
28			
29			

<b>30 Lesser of Actual Cost or Baseline Rate</b>	
31	Baseline Power Cost Rate \$44.482

32			
33	<b>Adjustment Needed?</b>		<b>Yes</b>
34	Adjustment needed if Baseline rate is lower than actual variable cost		
35			
36	Adjustment Rate	(\$/MWh)	-\$0.518
37	Adjustment volume	(MWh)	750,000
38	Adjustment Amount	(\$)	\$ (388,500) to Exhibit B line 24