EXHIBIT NO. ___(JHS-8)
DOCKET NO. UE-07___/UG-07___
2007 PSE GENERAL 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-07____** **Docket No. UG-07____**

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

DECEMBER 3, 2007

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. <u>**Sharing proposal:**</u>

- **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. <u>**Timing of surcharges or credits:**</u>

- 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

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

[1] 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 areconsistent 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.

By Kimberly Harris
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 ffitch
Assistant Attorney General
Public Counsel Section Chief

AT&T WIRELESS SERVICES, INC.

By ______________________________
Its ______________________________

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Robert Cedarbaum
Shannon Smith
Assistant Attorneys General

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Shannon Smith
Assistant Attorneys General

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

By ______________________________ 6/6/02
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Shannon Smith
Assistant Attorneys General

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

By ______________________
Simon ffitch
Assistant Attorney General
Public Counsel Section Chief

AT&T WIRELESS SERVICES, INC.

By Chris Caley C.F.M.
Its Commodity Manager

6/4/02

COGENERATION COALITION OF WASHINGTON

By Donald Brookhyser
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Attorney for Cogeneration Coalition of Washington

KROGER CO.

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

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Its ______________________

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Exhibit A-1 Power Cost Rate

Row		Test Year	Test Yr $/MWh		Rate Year	
3	Regulatory Assets (Variable)	$ 284,728,294				
4	Transmission Rate Base (Fixed)	122,217,537				
5	Production Rate Base (Fixed)	482,094,767				
6		$ 889,040,598				
7	Net of tax rate of return	7.30%				
8						
9						
10	Regulatory Asset Recovery	$ 31,977,178	$ 1.677	(c)		
11	Fixed Asset Recovery	67,868,920	$ 3.560	(a)	69,852,738	
12	501-Steam Fuel	32,511,186	$ 1.705	(c)		
13	555-Purchased power	527,080,489	$ 27.648	(c)		
14	557-Other Power Exp	7,447,583	$ 0.391	(a)	7,665,277	
15	547-Fuel	61,173,325	$ 3.209	(c)		
16	565-Wheeling	41,435,360	$ 2.174	(c)		
17	Variable Transmission Income	(6,510,985)	$ (0.342)	(c)		
18	Hydro and Other Pwr.	51,597,583	$ 2.707	(a)	53,105,787	
19	447-Sales to Others	(37,525,193)	$ (1.968)	(c)		
20	456-Subaccounts 00016 & 00018	1,077,379	$ 0.057	(c)		
21	Transmission Exp - 500KV	342,495	$ 0.018	(a)	352,506	
22	Depreciation fixed	40,979,607	$ 2.150	(a)	42,177,446	
23	Amortization Regulatory Assets	15,035,627	$ 0.789	(c)		
24	Property Taxes	13,124,556	$ 0.688	(a)	13,508,189	
25	Subtotal & Baseline Rate	$ 847,615,110	$ 44.463	(b)	186,661,943	(d)
26	Revenue Sensitive Items	0.9552337				
27		$ 887,337,947				
28	Test Year Load (MWH's)	19,063,867	<-- includes Firm Wholesale			
29		Before Rev. Sensitive Items	After Rev. Sensitive Items			
30	Power Cost in Rates with Revenue Sensitive Items (the adjusted baseline		46.547			
31	sum of (a) = Fixed Rate Component	9.514	9.960			
32	(b) = Power Cost Rate	44.463	46.547			
33	sum of (c) = Variable Power Rate	34.949	36.587			
34	Component					
35						
36	* Regulatory Assets are Tenaska, Encogen Fuel Buyout and BEP					
37						
38	(d) It is the Company's proposal to shape the fixed costs based upon					
39	historical retail revenues shape or historical monthly expense shape. The					
40	purpose is to prevent seasonal swings in the deferral account. Details to					
41	be determined.					

Exhibit A-2 Transmission Costs

Row			Date	DR (CR) Accumulated Deferred Income Income Tax Balance	
8	Colstrip Related Transmission Assets				
9					
10	Balance at:		6/30/01	(15,759,774)	
11	No deferred income taxes associated with the 3rd AC Intertie,				
12	Northern Intertie and BPA Transmission Assets.				
13					
14	Test Period Property Taxes on transmission Related Assets:				
15			Amount		
16	Oregon-3rd AC Intertie		$864,630		
17	Montana-Transmission Assets		1,619,726		
18	Montana-Beneficial Use Property Taxes on BPA				
19	Transmission Assets		1,826,626		
20	Washington-Northern Intertie		127,735		
21	Total Property Taxes		$4,438,717		
22					
23	Wheeling Expense		41,435,360		
24					
25	Transmission Plant				
26					
27		TRANS - COLSTRIP 1 & 2	AMA 6/30/01	Accum. Dep.	Depreciation Exp.
28	E351	Easements	685,927	264,280	17,011
29	E353	Station Equipment	1,231,131	682,186	34,964
30	E354	Towers & Fixtures	14,474,343	5,917,036	374,885
31	E355	Poles & Fixtures	49,007	39,834	774
32	E356	OH Condcutors & devices	13,158,153	5,749,080	369,744
33	E359	Roads & Trails	113,968	43,839	2,872
34	COLSTRIP 1&2 TRANSMISSION		29,712,529	12,696,255	800,250
35					
36		TRANS - COLSTRIP 3 & 4			
37	E351	Easements	1,071,124	396,585	27,314
38	E352	Structures & Improvements	478,326	188,636	11,719
39	E353	Station Equipment	17,687,015	6,706,154	578,365
40	E354	Towers & Fixtures	20,422,516	8,020,387	541,197
41	E355	Poles & Fixtures	122,619	58,220	3,298
42	E356	OH Conductors & Devices	20,015,734	8,474,189	572,450
43	E359	Roads & Trails	341,015	127,820	8,730
44	COLSTRIP 3&4 TRANSMISSION		60,138,349	23,971,991	1,743,073
45					
46		TRANS - 3RD NW-SW INTERTIE			
47	E352	Structures & Improvements	1,276,264	183,547	22,845
48	E353	Station Equipment	31,157,075	5,529,150	716,613
49	E354	Towers & Fixtures	22,781,417	3,276,322	430,569
50	E355	Poles & Fixtures	204,200	19,787	5,268
51	E356	OH Conductors & devices	23,458,461	4,528,227	609,920
52	E359	Roads & Trails	59,215	4,141	628
53	TOTAL 3RD NW-SW INTERTIE		78,936,632	13,541,174	1,785,843
54					
55		TRANS - NORTHERN INTERTIE			
56	E351	Easements - Whatcom		-	-
57	E354	Towers & Fixtures-Whatcom	5,744,097	533,604	106,840
58	E355	Poles & Fixtures-Whatcom	11,219	1,702	289
59	E356	OH Conductors & Devices-Whatc	7,460,099	904,353	193,963
60	E355	Poles & Fixtures-Skagit	3,398,685	416,680	87,686
61	E356	OH Conductors & Devices-Skagit	5,142,699	501,239	133,710
62	TOTAL NORTHERN INTERTIE		21,756,799	2,357,577	522,488
63					
64	Total Transmission		190,544,309	52,566,998	4,851,654
65	Less				
66	Accumulated Depreciation		52,566,998		
67	Deferred Taxes		15,759,774		
68	Transmission Ratebase		122,217,537		

Exhibit A-3 Colstrip Fixed Costs

Row	Revenue Requirement for Colstrip		
4	Plant	647,044,432	
5	Accumulated Depreciation	(329,162,409)	
6	Deferred Taxes	(93,634,221)	
7	Net Plant	224,247,802	
8	Rate of Return (net of Tax)	7.30%	
9	Revenue Requirement after tax	16,370,090	
10	Plant Revenue Requirement	25,184,753	(Adjusted for Federal Tax)
11	Expenses	52,329,884	
12	Total Revenue Requirement	77,514,637	(before revenue sensitive items)
13			
14	Support for Revenue Requirement - Ratebase		

Row	FERC	DESCRIPTION	30-Jun-00	30-Jun-01	13 MONTH AMA	ANNUITY RATE	ANNUALIZED DEPRECIATION	ACUMM. DEPR. 06/30/2001
16		COLSTRIP #1						
17	E311	Structures & Improvements	6,931,939	7,097,390	7,021,558	3.03%	212,753	4,519,382
18	E312	Boiler Plant Equipment	46,965,650	48,224,007	47,159,778	3.12%	1,471,385	30,962,573
19	E314	Turbo Generating Units	12,437,937	12,437,937	12,437,937	3.29%	409,208	8,005,683
20	E315	Accessory Electric Equip.	7,042,053	7,043,604	7,042,893	2.71%	190,862	4,440,864
21	E316	Misc. Power Plant Equip.	365,117	426,565	398,402	3.87%	15,418	215,987
22		TOTAL	73,742,696	75,229,503	74,060,568	3.11%	2,299,626	48,144,488
23		COLSTRIP #2						
24	E311	Structures & Improvements	5,317,757	5,573,640	5,456,360	3.06%	166,965	3,343,898
25	E312	Boiler Plant Equipment	39,821,935	40,460,296	40,167,714	3.05%	1,225,115	26,457,593
26	E314	Turbo Generating Units	12,178,755	12,519,462	12,363,305	3.26%	403,044	7,691,610
27	E315	Accessory Electric Equip.	4,536,518	4,592,474	4,566,828	2.69%	122,848	2,797,275
28	E316	Misc. Power Plant Equip.	365,931	427,379	399,215	3.61%	14,412	217,888
29		TOTAL	62,220,895	63,573,251	62,953,422	3.07%	1,932,384	40,508,264
30		COLSTRIP 1 & 2 COMMON						
31	E311	Structures & Improvements	30,345,256	31,983,349	31,232,556	3.16%	986,949	18,788,553
32	E312	Boiler Plant Equipment	8,623,422	8,679,337	8,653,709	3.18%	275,188	5,533,214
33	E314	Turbo Generating Units	3,918,858	3,918,858	3,918,858	3.31%	129,714	2,382,313
34	E315	Accessory Electric Equip.	2,377,984	2,420,179	2,400,840	3.07%	73,706	1,334,875
35	E316	Misc. Power Plant Equip.	6,235,545	6,561,728	6,412,227	3.82%	244,947	3,136,065
36		TOTAL	51,501,064	53,563,451	52,618,190	3.25%	1,710,504	31,175,020
37		COLSTRIP 3						
38	E311	Structures & Improvements	28,829,642	28,882,948	28,858,516	2.45%	707,034	14,566,340
39	E312	Boiler Plant Equipment	113,898,277	115,756,485	113,618,072	2.68%	3,044,964	57,262,237
40	E314	Turbo Generating Units	32,936,825	33,180,681	33,068,914	2.97%	982,147	14,166,239
41	E315	Accessory Electric Equip.	6,401,615	6,401,615	6,401,615	2.47%	158,120	2,874,151
42	E316	Misc. Power Plant Equip.	454,762	480,140	468,508	2.86%	13,399	210,034
43		TOTAL	182,521,121	184,701,869	182,415,625	2.69%	4,905,664	89,079,001
44		COLSTRIP 4						
45	E311	Structures & Improvements	26,542,394	26,595,701	26,571,269	2.54%	674,910	11,552,369
46	E312	Boiler Plant Equipment	99,709,843	100,508,440	100,142,416	2.75%	2,753,916	43,898,286
47	E314	Turbo Generating Units	27,895,777	28,602,598	28,278,638	2.94%	831,392	10,813,318
48	E315	Accessory Electric Equip.	5,589,362	5,596,707	5,593,341	2.52%	140,952	2,163,849
49	E316	Misc. Power Plant Equip.	650,784	676,163	664,531	2.79%	18,540	277,867
50		TOTAL	160,388,160	161,979,609	161,250,195	2.74%	4,419,710	68,705,690
51		COLSTRIP 3 & 4 COMMON						
52	E311	Structures & Improvements	71,951,771	72,034,845	71,996,769	2.33%	1,677,525	35,209,226
53	E312	Boiler Plant Equipment	20,855,440	20,915,298	20,887,863	2.48%	518,019	10,585,040
54	E314	Turbo Generating Units	274,553	274,553	274,553	2.62%	7,193	125,852
55	E315	Accessory Electric Equip.	7,706,935	7,748,971	7,729,705	2.31%	178,556	3,422,068
56	E316	Misc. Power Plant Equip.	4,861,282	5,098,460	4,989,753	2.79%	139,214	2,083,870
57		TOTAL	105,649,981	106,072,127	105,878,643	2.38%	2,520,507	51,426,057
58		COLSTRIP 1-4 COMMON						
59	E316	Misc. Power Plant Equip.	253,865	253,865	253,865	2.46%	6,245	123,888
60		TOTAL	253,865	253,865	253,865	2.46%	6,245	123,888
61	COLSTRIP COMMON FERC ADJ.		8,316,981					
62	COLSTRIP DEF DEPR FERC ADJ.		2,449,668					
63		Total Plant and Acc. Deprec.	647,044,432				17,794,640	329,162,409

Exhibit A-3 Colstrip Fixed Costs

Row			
69	Support for Revenue Requirement - Expenses		
70			Amount before
71	Order	Description	Prod. Adj.
72	50004011	1&2 Sup & Eng	76,685
73	50005011	3&4 Sup & Eng	108,581
74	50204001	1&2 Steam Exp	1,217,034
75	50205001	3&4 Steam Exp	624,831
76	50504001	1&2 Elec Exp	(208,933)
77	50505001	3&4 Elec Exp	(223,913)
78	50604001	1&2 Misc Exp	3,320,269
79	50605001	3&4 Misc Exp	2,515,968
80	50605002	3&4 Steam	(2,399)
81	50704001	1&2 Rents	95,991
82	50705001	3&4 Rents	131,692
83	51004001	1&2 Maint Supv	669,151
84	51005001	3&4 Maint Supv	539,405
85	51104001	1&2 Maint of Struct	405,072
86	51105001	3&4 Maint of Struct	373,938
87	51204001	1&2 Maint of Boiler	4,902,128
88	51205001	3&4 Maint of Boiler	5,967,278
89	51304001	1&2 Maint of E Plant	(178,069)
90	51305001	3&4 Maint of E Plant	705,533
91	51404001	1&2 Maint of Misc	4,578,888
92	51405001	3&4 Maint of Misc	1,159,196
93		Property Taxes-Montana	6,027,509
94		Electric Energy Tax	1,729,406
95	403xxxxx	Depreciation	17,794,640
96			$52,329,884

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 AMOUNT	PRODUCTION 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			After Production Adj.
32	BPA POWER EXCHANGE INVESTMENT	51,135,941	sum of L32 thru	293,050,941	284,728,294
33	TENASKA REGULATORY ASSET	229,424,000	L34		
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)			Less Regulatory Assets
43	ADJUSTMENT TO RATE BASE	789,237,403	(22,414,342)	766,823,061	482,094,767

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			$\boxed{\$ 1,177,084,685}$

Exhibit B: Power Costs Subject to PCA Sharing

Row						Example Jul 02 - Jun 03	Explanation or source
4							
5	Return on Fixed RB				$	69,852,738	from Exhibit A-1 line 11 - production and transmission ratebase adjusted to Rate Year
6	Other Fixed Costs					116,809,205	from Exhibit A-1 lines 14,18,21,22, & 24 (557, Hydro and Other Prod. O&M, 500 KV O&M, Depreciation fixed, Property tax) adjusted to Rate Year
7	Subtotal Fixed Costs				$	186,661,943	
8	Total Variable Component Actual						
9	Steam Oper. Fuel	501		illustrative est.	$	33,461,494	SAP - actual
10	Other Pwr Gen Fuel	547		illustrative est.		55,009,484	SAP - actual
11	Other Elec Revenues	45600012, 18		illustrative est.		(165,000)	SAP - actual Non Core Gas (sales) / purchases orders 45600012, 45600018
12	Purchase Power	555		illustrative est.		538,456,725	SAP - actual
13	Sales to Other Util	447		illustrative est.		(35,448,055)	SAP - actual
14	Wheeling	565		illustrative est.		43,496,800	SAP - actual
15	Transmission Revenue	45600017		illustrative est.		(5,000,000)	SAP - actual Transmission revenues on 3rd AC, Northern Intertie, Colstrip lines
16	Regulatory Assets			illustrative est.		36,867,841	from Exhibit D line 35. Amortization and return on regulatory assets for PCA period
17							
18	SUBTOTAL before Adjustments			642,456.32	$	853,341,232	
19							
20	**Adjustments:**						
21	Prudence from UE-921262			illustrative est.	$	(2,260,152)	Prudence adj. = 3% * March Pt 2 payments; and 1.2% * Tenaska payments
22	Contract price adjustment			illustrative est.		(1,094,429)	from Exhibit E line 42
23	Colstrip availability adjustment			illustrative est.		(5,712,733)	from Exhibit F line 40
24	New resource pricing adjustment			illustrative est.		(388,500)	from Exhibit G line 38
25							
26	Subtotal Adjustments				$	(9,455,814)	
27							
28	**Total allowable cost**				$	843,885,418	
29							
30	PCA period delivered load			est. actual		19,110,518	Actual delivered MWh during PCA period = Total load net of losses
31	**Baseline Power Cost**	$44.463			$	849,710,975	Base line rate from Exhibit A-1 line 25
32							
33	Imbalance for Sharing				$	(5,825,557)	to Exhibit C column (C). A portion of the imbalance will be allocated to firm wholesale customers based upon the allocation used in the most recent Docket approving rate spread.
34	positive is potential customer surcharge, negative is potential customer credit						
35							
36	**Company's Share**	band limit +/-					
37	First band - deadband	$ 20,000,000	100%	(5,825,557)	$	(5,825,557)	
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			(5,825,557)	$	(5,825,557)	to Exhibit C column (G)
42							
43	**Customer Share (deferral account)**				$	-	to Exhibit C column (D)

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

	(C) Imbalance for Sharing Ex. B line 33	(D) Customer Annual Share = "Deferral" Ex. B line 43	(E) Customer Annual Share over Cap at 99%	(F) End Period Customer Deferral Balance	(G) Company Annual Share Ex. B line 41	(H) Potential transfer (to) / from customer	(I) Company share over Cap at 1%	(J) End Period Company Share	(K) Company Accum Share w/o Cap	(L) Accum. Amount Over Cap	(M) Annual Change in Amount over Cap
PCA Yr #1	$ (5.83)	$ -	$ -	$ -	$ (5.83)	$ -	$ -	$ (5.83)	$ (5.83)	$ -	$ -
PCA Yr #2	$ 30.00	$ 5.00	$ -	$ 5.00	$ 25.00	$ -	$ -	$ 19.17	$ 19.17	$ -	$ -
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
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
Check	$ 84.2	OK		$ 43.9				$ 40.3			

PC ative

Exhibit C - Application of $40 million Cap

Row

3 **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
4 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
5 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
6 set for refund or collection at that time.
7
8
9

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

24 **$ In Millions**

Row		(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
26–28		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
29	PCA Yr #1	$ 30.0	$ 5.0	$ -	$ 5.0	$ 25.0	$ -	$ -	$ 25.0	$ 25.0	$ -	$ -
30	PCA Yr #2	$ -	$ -	$ -	$ 5.0	$ -	$ -	$ -	$ 25.0	$ 25.0	$ -	$ -
31	PCA Yr #3	$ (100.0)	$ (64.0)	$ -	$ (59.0)	$ (36.0)	$ -	$ -	$ (11.0)	$ (11.0)	$ -	$ -
32	PCA Yr #4	$ 36.0	$ 8.0	$ -	$ (51.0)	$ 28.0	$ -	$ -	$ 17.0	$ 17.0	$ -	$ -
33												
34	Check	$ (34.0)	OK		$ (51.0)				$ 17.0			
35												

Exhibit C - Application of $40 million Cap

Row

3 **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
4 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
5 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
6 set for refund or collection at that time.
7
8
9

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

37 **$ In Millions**

Row		(C) Imbalance for Sharing Ex. B line 33	(D) Customer Annual Share = "Deferral" Ex. B line 43	(E) Customer Annual Share over Cap at 99%	(F) End Period Customer Deferral Balance	(G) Company Annual Share Ex. B line 41	(H) Potential transfer (to) / from customer	(I) Company share over Cap at 1%	(J) End Period Company Share	(K) Company Accum Share w/o Cap	(L) Accum. Amount Over Cap	(M) Annual Change in Amount over Cap
38												
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	$ 66.0	OK		$ 25.9				$ 40.1			
48												

Exhibit C - Application of $40 million Cap

Row

3 **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
4 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
5 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
6 set for refund or collection at that time.
7
8
9

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

50 **$ In Millions**

Row		(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
52–53		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
54												
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)	$ (89.0)	$ (49.0)	$ (28.0)
58	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
59												
60	Check	$ (66.0)	OK		$ (25.9)				$ (40.1)			
61												

Exhibit D: Regulatory Assets

Row		Year		Interest	Amort	Balance	PCA (Jul-Jun) Amortization	Ratebase (AMA)	7.30%	Return + Amort
4	Cabot Buyout									
5										
6		2000	$ 12,588,000	709,000	(312,000)	12,985,000				
7		2001	$ -	720,000	(741,000)	12,964,000				
8		2002	$ -	731,000	(1,070,000)	12,625,000	(1,239,500)	12,491,033	$ 911,845	$ 2,151,345
9		2003	$ -	-	(1,409,000)	11,216,000	(1,588,500)	11,170,908	$ 815,476	$ 2,403,976
10		2004	$ -	-	(1,768,000)	9,448,000	(1,965,500)	9,398,408	$ 686,084	$ 2,651,584
11		2005	$ -	-	(2,163,000)	7,285,000	(2,388,500)	7,228,408	$ 527,674	$ 2,916,174
12		2006	$ -	-	(2,614,000)	4,671,000				
13										
14	Tenaska		-							
15		1998	$ 215,000,000	8,754,000	(1,952,000)	221,802,000				
16		1999	$ -	8,795,000	(3,863,000)	226,734,000				
17		2000	$ -	8,849,000	(5,463,000)	230,120,000				
18		2001	$ -	8,838,000	(7,382,000)	231,576,000				
19		2002	$ -	8,749,000	(9,494,000)	230,831,000	(10,709,000)	229,424,000	$ 16,747,952	$ 27,456,952
20		2003	$ -	-	(11,924,000)	218,907,000	(13,334,000)	218,552,512	$ 15,954,333	$ 29,288,333
21		2004	$ -	-	(14,744,000)	204,163,000	(16,326,000)	203,765,512	$ 14,874,882	$ 31,200,882
22		2005	$ -	-	(17,908,000)	186,255,000	(19,261,500)	185,914,637	$ 13,571,769	$ 32,833,269
23		2006	$ -	-	(20,615,000)	165,640,000				
24										
25	BEP									
26		2001				54,662,518				
27		2002			(3,526,620)	51,135,898	(3,526,620)	51,135,941	$ 3,732,924	$ 7,259,544
28		2003			(3,526,620)	47,609,278	(3,526,620)	47,609,278	$ 3,475,477	$ 7,002,097
29		2004			(3,526,620)	44,082,658	(3,526,620)	44,082,658	$ 3,218,034	$ 6,744,654
30		2005			(3,526,620)	40,556,038	(3,526,620)	40,556,038	$ 2,960,591	$ 6,487,211
31		2006			(3,526,620)	37,029,418				
32										
33										

Row	From	To		Return + Amort
34				
35	Jul-02	Jun-03	PCA#1	$ 36,867,841
36	Jul-03	Jun-04	PCA#2	$ 38,694,407
37	Jul-04	Jun-05	PCA#3	$ 40,597,120
38	Jul-05	Jun-06	PCA#4	$ 42,236,653
39				

PC/ /e

Exhibit E - Contract Adjustments

Estimated costs from hypothetical PCA period

Row		Note	Limit - Rate or Total Cost per UE-011570	PCA Period: Generation MWh	PCA Period: NUG Gen. MWh	PCA Period: NUG Displ. MWh	PCA Period: Total Cost $	PCA Period: Actual Rate	Rate Change	Adjust for Positive Differences
7	CONTRACTS									
8	Baker Replacement	Exchange								
9	BC Hydro Point Roberts	Rate Limit	$ 67.00	21,432			$ 1,436,000	$ 67.00	$ 0.00	$ 42
10	BPA WNP-3 Exchange Power	Rate Limit	$ 28.17	384,834			$ 10,892,000	$ 28.30	$ 0.13	$ 49,434
11	BPA WNP3 Return	Actual Cost								
12	BPA Snohomish Conservation	Rate Limit	$ 51.35	92,170			$ 4,733,000	$ 51.35	$ (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	$ 64.05	$ 1.20	$ 47,000
21	WWP Contract 15 yr	Actual Cost through 12/31/02								
22	PG&E Exchange Storage Acctg.	Exchange								
23	QF Shipp Hutch. Creek	Rate Limit	$ 30.04	1,731			$ 52,000	$ 30.04	$ -	$ -
24	QF Koma Kulshan Hydro	Rate Limit	$ 74.87	32,692			$ 2,448,000	$ 74.88	$ 0.01	$ 480
25	QF March Point Cogen 1 Winter	NUG Rate Limit	$ 61.01	436,000	436,000	-	$ 26,639,600	$ 61.10	$ 0.09	$ 37,941
26	QF March Point Cogen 1 Summer	NUG Rate Limit	$ 43.70	281,000	181,000	100,000	$ 12,279,700	$ 43.70	$ -	$ -
27	QF March Point Cogen 2 Winter	NUG Rate Limit	$ 66.00	330,000	330,000	-	$ 22,011,000	$ 66.70	$ 0.70	$ 229,552
28	QF March Point Cogen 2 Summer	NUG Rate Limit	$ 55.30	232,000	132,000	100,000	$ 12,829,600	$ 55.30	$ -	$ -
29	QF Port Townsend Hydro	Rate Limit	$ 28.21	2,694			$ 76,000	$ 28.21	$ -	$ -
30	QF PERC Puyallup	Actual Cost								
31	QF Spokane MSW	Rate Limit	$ 87.54	141,552			$ 12,397,000	$ 87.58	$ 0.04	$ 6,000
32	QF Sumas Winter	NUG Rate Limit	$ 81.84	663,000	663,000	-	$ 54,631,200	$ 82.40	$ 0.56	$ 373,980
33	QF Sumas Summer	NUG Rate Limit	$ 59.20	461,000	361,000	100,000	$ 27,291,200	$ 59.20	$ -	$ -
34	QF Sygitowicz	Rate Limit	$ 51.37	1,421			$ 73,000	$ 51.37	$ -	$ -
35	QF Tenaska (excl. Reg. Amort.)	NUG Rate Limit	$ 31.84	1,958,028	1,858,028	100,000	$ 62,069,488	$ 31.70	$ (0.14)	$ -
36	QF Twin Falls	Rate Limit	$ 75.00	69,955			$ 5,246,625	$ 75.00	$ (0.00)	$ -
37	QF Weeks Falls	Rate Limit	$ 75.00	12,542			$ 940,650	$ 75.00	$ (0.00)	$ -
38	Skookumchuck	Actual Cost								
39										
40	TOTAL									$ 1,094,429
41										
42	Notes:						Reverse sign and enter on Exhibit B line 22			$ (1,094,429)

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

Exhibit F - Colstrip Availability Adjustment

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

	1&2	3&4	PSE Wtd	days
PSE MW ->	307	370		
Jul-02	85.00%	85.00%	85.0%	31
Aug-02	85.00%	85.00%	85.0%	31
Sep-02	85.00%	85.00%	85.0%	30
Oct-02	85.00%	85.00%	85.0%	31
Nov-02	85.00%	85.00%	85.0%	30
Dec-02	85.00%	85.00%	85.0%	31
Jan-03	85.00%	85.00%	85.0%	31
Feb-03	85.00%	85.00%	85.0%	28
Mar-03	85.00%	0.00%	38.5%	31
Apr-03	85.00%	0.00%	38.5%	30
May-03	85.00%	0.00%	38.5%	31
Jun-03	85.00%	0.00%	38.5%	30
12 mo Average	85.00%	56.59%	69.47%	
Weighted by days in the month			Weighted by Plant Capacity and days/month	

PSE: Enter date of 12 months prior to end of PCA period.

Part 2. Calculate annual availability penalty ratio

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

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

Part 3. Calculate Annual Colstrip Fixed Cost Penalty

Total Fixed Cost	$ 77,514,638	from Exhibit A-3 (Colstrip Total Revenue Requirement)
Penalty Ratio =	-7.37%	
Penalty $	**$ (5,712,733)**	**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	
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	Actual data
13	Sep-01	80.02%	93.18%	30	
14	Oct-01	96.70%	95.99%	31	
15	Nov-01	96.71%	90.40%	30	
16	Dec-01	90.64%	86.21%	31	
17	Jan-02	93.60%	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	Example data
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	
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	

Exhibit G - New Resource Adjustment

Row				
3	**For New Resources with a Terms Longer than 2 Years**			
4				
5	**Name**	Sample new plant		
6	**Description**	Combined cycle gas turbine		
7		In-service date January 2003		
8				
9				
10	**PCA Period**	July 2002 - June 2003		
11				
13	**Total Variable Component Actual**			
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				
23	PCA Period Generation	(MWh)		750,000
24				
25	**Actual Variable Cost**	**($/MWh)**		**$45.000**
26	Compare with Baseline Rate			
27				
28	**Baseline Power Cost Rate**	**($/MWh)**		**$44.482**
29				
30	**Lesser of Actual Cost or Baseline Rate**			
31	Baseline Power Cost Rate			$44.482
32				
33	**Adjustment Needed?**			**Yes**
34	Adjustment needed if Baseline rate is lower than actual variable cost			
35				
36	Adjustment Rate	($/MWh)		-$0.518
37	Adjustment volume	(MWh)		750,000
38	**Adjustment Amount**	($)	**$**	**(388,500)** to Exhibit B line 24