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.	Docket No. UE
PUGET SOUND ENERGY, INC.,	
Respondent.	

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

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

	Total Revenue Requirement	
	Total Rate	I
Powe	Non-power Costs	
Variable Rate Component	Fixed Rate Component	
Fuel Other revenues and costs associated with fuel	Following items to be recovered at the last general rate case or PCA resource case revenue levels:	Transmission (other than what has been included in PCA fixed rate component).
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	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,	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.
- 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. <u>Power Cost Only Rate Review:</u> 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.
- 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. <u>Binding on Parties:</u> 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. <u>Integrated Terms of Settlement:</u> 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. <u>Negotiated Agreement</u>: 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 <u>Execution:</u> 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.
BySimon ffitch Assistant Attorney General Public Counsel Section Chief	By Its

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ByKimberly Harris	By Robert Cedarbaum
Vice President of Regulatory Affairs	Shannon Smith Assistant Attorneys General
PUBLIC COUNSEL SECTION, OFFICE OF THE ATTORNEY GENERAL OF THE STATE OF WASHINGTON	AT&T WIRELESS SERVICES, INC.
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SETTLEMENT TERMS FOR PCA - 8
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Ву	Ву
Kimberly Harris	Robert Cedarbaum
Vice President of Regulatory Affairs	Shannon Smith
	Assistant Attorneys General
PUBLIC COUNSEL SECTION, OFFICE OF THE ATTORNEY GENERAL OF THE STATE OF WASHINGTON 6/6/02	AT&T WIRELESS SERVICES, INC.
Simon ffitch	Its
Assistant Attorney General Public Counsel Section Chief	

__(JHS-3) Exhibit No. Page 11 of 30

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By

DATED this 4th day of June, 2442.

fuget sound energy, Inc.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION STAFF

Kimberly Harris Vice President of Regulatory Affairs Robert Cederbuum Shannon Smith Assistant Amorneys General

PUBLIC COUNSILL ENCTION, OFFICE OF THE ATTORNEY GENERAL OF THE STATE OF WASHINGTON

atat wireless services, inc.

By. Simon Mitch Assistant Attorney General Public Counsel Section Chief

Exhibit No. ___(JHS-3) Page 12 of 30

COGENERATION COALITION OF WASHINGTON

KROGER CO.

Donald Brookhyser

Attorney for Cogeneration
Coalition of Washington

Michael L. Kurtz /
Attorney for Kroger Co.

NW ENERGY COALITION and NATURAL RESOURCES DEFENSE COUNCIL

Policy Associate, NW Energy Coalition

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Attorney for Cogeneration	:	Attorney	for Kroger	Co.
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SETTLEMENT TERMS FOR PCA

PUBLIC COUNSEL SECTION, OFFICE OF THE ATTORNEY GENERAL OF THE STATE OF WASHINGTON AT&T WIRELESS SERVICES, INC. By_ By_ Simon ffitch Its_ Assistant Attorney General Public Counsel Section Chief **COGENERATION COALITION OF** KROGER CO. WASHINGTON By. Donald Brookhyser Michael L. Kurtz Attorney for Cogeneration Attorney for Kroger Co. Coalition of Washington NW ENERGY COALITION and NATURAL RESOURCES DEFENSE

Policy Associate, NW Energy Coalition

COUNCIL

Danielle Dixon

	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	T Toddollor Male Bees (Male a)	\$	903,148,823	•		
7	Net of tax rate of return	•	7.30%			
	Met of fax face of fermin			Test Yr		
8				\$/MWh		Rate Year
9	B. Address Assert Description	\$	31,977,178	\$ 1.677	(c)	, , , , , , , , , , , , , , , , , , , ,
10	Regulatory Asset Recovery	Ψ	54,142,951	\$ 2.840		55,725,557
11 ·	Fixed Asset Recovery-Prod Factored			\$ 0.803		15,310,432
12	Fixed Asset Recovery Other		15,310,432	\$ 0.803 \$ 1.705		10,010,402
13	501-Steam Fuel		32,511,186	\$ 1.703 \$ 27.643		
14	555-Purchased power		526,980,333	•	, ,	11,835,209
15	557-Other Power Exp		11,499,089	\$ 0.603	• •	11,000,200
16	547-Fuel		61,173,325		(c)	
17	565-Wheeling		41,435,360	\$ 2.174	(c)	
18	Variable Transmission Income		(6,510,985)			50 405 707
19	Hydro and Other Pwr.		51,597,583	\$ 2.707		53,105,787
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		352,506
23	Depreciation-Production		36,265,740	\$ 1.902	(a)	37,325,792
24	Depreciation-Transmission		4,851,654	\$ 0.254		4,851,654
25	Property Taxes-Production		8,343,174	\$ 0.438		8,600,747
25 26	Property Taxes-Transmission		4,441,860	\$ 0.233		4,441,860
	Property raxes-framsmission				T	
27	Subtotal & Baseline Rate	\$	837,913,560	\$ 43.953	(b)	191,549,544
28	Revenue Sensitive Items		0.9552337			
29		\$	877,181,741			8,343,174
30	Test Year Load (MWH's)		19,063,867	< includ	les Firm \	Wholesale
31	Before R	ev. S	ensitive Items	After Rev.	Sensitiv	<u>e Items</u>
٠.	Power Cost in Rates with					
	Revenue Sensitive Items (the					
32	adjusted baseline			46.013		
33	sum of (a) = Fixed Rate Component		9.798	10,257		
34	(b) = Power Cost Rate		43.953	46.013		
35	sum of (c) = Variable Power Rate		34.155	35.756		
36	Component		0 1. 100	••••		
37	Component					
	* Regulatory Assets are Tenaska, Encogen F	ع امین	Suvout and REP	•		
38	Regulatory Assets are reliaska, Encogen F	uei C	Juyout and DEF			
39						
40						
41						
42						
42						

43

Exhibit A-2 Transmission Costs

Row	LAHMR A-Z III		Date	DR (CR) Accumulated Deferred income Income Tax Balance	
8	Coistrip Related Tra	insmission Assets			
9	Balance at:		06/30/2001	(15,759,774)	
10 11	No deferred income	taxes associated with the 3rd AC In	tertie,		
12	Northern Intertie an	d BPA Transmission Assets.			
13	W. of Builded Broads	y Taxes on transmission Related As:	sets:		
14 15	lest Period Propert	y Takes Of Classical Medica Act	Amount		
16	Oregon-3rd AC Intert		\$864,624		
17	Montana-Transmissi		1,622,875		
18		Ise Property Taxes on BPA	1,826,626		
19 20	Transmission Asset Washington-Northern		127,735		
21	Total Property Taxe		\$4,441,860	•	
22			44 425 260		
23	Wheeling Expense		41,435,360		
24 25	Transmission Plant				
26	11411311113011111		Plant	A	Depreciation Exp.
27		TRANS - COLSTRIP 1 & 2	AMA 6/30/01 685.927	Accum. Dep. 264,280	17,011
28 - 29	E351 E353	Easements Station Equipment	1,231,131	682,186	34,964
∞ 29 30	E354	Towers & Fixtures	14,474,343	5,917,036	374,885
31	E355	Poles & Fixtures	49,007	39,834	774 369,744
32	E356	OH Condcutors & devices	13,158,153	5,749,080 43,839	2.872
33	E359	Roads & Trails	113,968 29,712,529	12.696,255	800,250
34 35	COLSTRIP 182 TRA	NOMICIA	20,	,,-	
36		TRANS - COLSTRIP 3 & 4			67.044
37	E351	Easements	1,071,124	396,585 188,636	27,314 11,719
38	E352	Structures & Improvements	478,326 17,687,015	6.706.154	578,365
39 40	E353 E354	Station Equipment 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	8,474,189 127,820	572,450 8,730
43	E359	Roads & Trails	341,015 60,138,349	23,971,991	1,743,073
44 45	COLSTRIP 3&4 TRA	NOSCAMENT.	00,100,010		
46		TRANS - 3RD NW-SW INTERTIE			00.848
47	E352	Structures & Improvements	1,276,264	183,547	22,845 716,613
48	E353	Station Equipment	31,157,075 22,781,417	5,529,150 3,276,322	430,569
49	E354 E355	Towers & Fixtures Poles & Fixtures	204,200	19.787	5,268
50 51	E356	OH Conductors & devices	23,458,461	4,528,227	609,920
52	E359	Roads & Trails	59,215	4,141	1,785,843
53	TOTAL 3RD NW-SV	V INTERTIE	78,936,632	13,541,174	1,700,043
54 55		TRANS - NORTHERN INTERTIE			
56	E35 1	Easements - Whatcom			-
57	E354	Towers & Fixtures-Whatcom	5,744,097	533,604 1,702	106,840 289
58	E355	Poles & Fixtures-Whatcom	11,219 7, 460,09 9	904,353	193,963
59 60	E356 E355	OH Conductors & Devices-Whatc 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	T 4 1 Tin-in-		190,544,309	52,566,998	4,851,654
64 65	Total Transmission Less		100,077,000	,,	••
66	Accumulated Depre	eciation	52, 566,99 8		
67	Deferred Taxes		15,759,774	_	
68	Transmission Rateb	ase	122,217,537		
revised	1_A2	revised accumulated depreciation	50,141,171 124,643,364		

Exhibit A-3 Colstrip Fixed Costs

Revenue Requirement for Colstrip

Row

5

A-3 Page 1

650,197,157 Plant (320,264,159) **Accumulated Depreciation** (93,634,221) 236,298,777 Deferred Taxes Net Plant 7.30% Rate of Return (net of Tax) 17,249,811 Revenue Requirement after tax

Plant Revenue Requirement

26,538,170 (Adjusted for Federal Tax)

52,329,884 Expenses

78,868,054 (before revenue sensitive items) Total Revenue Requirement

Support for	Revenue F	Requirement	- Ratebase

FERC	DESCRIPTION	30-Jun-00	30-Jun-01	13 MONTH AMA	ANNUITY RATE	ANNUALIZED DEPRECIATION	ACUMM, DEPR. 06/30/2001
	COLSTRIP #1						
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
	TOTAL	73,742,696	75,229,503	74,060,568	3.11%	2,299,626	48,144,488
	COLSTRIP #2						
E311	Structures & Improvements	5,317,757	5,573,640	5,456,360	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	26,457,593
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
	TOTAL	62,220,895	63,573,251	62,953,422	3.07%	1,932,384	40,508,264
	COLSTRIP 1 & 2 COMMON						
E311	Structures & improvements	30,345,256	31,983,349	31,232,556	3.16%	986,949	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
	TOTAL	51,501,064	53,563,451	52,618,190	3.25%	1,710,504	31,175,020
	COLSTRIP 3						
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
	TOTAL	182,521,121	184,701,869	182,415,625	2.69%	4,905,664	89,079,001
	COLSTRIP 4						
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	43,898,286
E314	Turbo Generating Units	27,895,777	28,602,598	28,278,638	2.94%	831,392	10,813,318
E315	Accessory Electric Equip.	5,589,362	5,596,707	5,593,341	2.52%	140,952	2,163,849
E316	Misc. Power Plant Equip.	650,784	676,163	664,531	2.79%	18,540	277,867
	TOTAL	160,388,160	161,979,609	161,250,195	2.74%	4,419,710	68,705,690
	COLSTRIP 3 & 4 COMMON						
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
	TOTAL	105,649,981	106,072,127	105,878,643	2.38%	2,520,507	51,426,057
	COLSTRIP 1-4 COMMON						
E316	Misc. Power Plant Equip.	253,865	253,865	253,865	2.46%	6,245	123,888
	TOTAL	253,865	253,865	253,865	2.46%	6,245	123,888
COLSTRIP	COMMON FERC ADJ.	8,316,981		8,316,981			
COLSTRIP	DEF DEPR FERC ADJ.	2,449,668	_	2,449,668	•		
	Total Plant and Acc. Deprec.	647,044,432	-	650,197,157		17,794,640	329,162,409

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

A-3 Page 2

70	Support for	Revenue Requirement - Expens	es
71			Amount before
72	Order	Description	Prod. Adj.
73	50004011	1&2 Sup & Eng	76,685
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	2,51 5,968
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	51 405001	3&4 Maint of Misc	1,159,196
₋ 94		Property Taxes-Montana	6,027, 50 9
9 5		Electric Energy Tax	1,729,406
96	403100000	Depreciation	17,794,640
97			\$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 2	PRODUCTION WAGE INCREASE PURCHASED POWER	0		0	
3	OTHER POWER SUPPLY TOTAL PRODUCTION WAGE INCREASE	0		0	
5 6 7	PAYROLL OVERHEADS PROPERTY INSURANCE	783,939 1,026,555		7,792 10,204	
, 8 9	TOTAL A&G	1,810,494		17,996	
10 11	DEPRECIATION PRODUCTION PROPERTY DEPRECIATION / AMORTIZATION	37,325,792		263,024 35,055	
12 13 14	PURCHASED POWER FUEL TOTAL	3,526,620 0 40,852,412	<u> </u>	0	
15 16	TAXES OTHER-PRODUCTION PROPERTY	,,	• • • •		
17 18	PROPERTY TAXES - WASHINGTON PROPERTY TAXES - MONTANA	3,041,963 6,027,509	(171,181)	59,913	
19 20 21	ELECTRIC ENERGY TAX PAYROLL TAXES TOTAL TAXES OTHER	1,729,406 630,032 11,428,910	(17,893)	6,263	
22 23	INCREASE(DECREASE) INCOME	2., , .	1,536,208		
24 25	INCREASE(DECREASE) FIT INCREASE(DECREASE) NOI			429,678 1,106,530	
26 27 28	RATE BASE: PRODUCTION PROPERTY	1,065,115,283			
29 30	COLSTRIP COMMON FERC ADJ. COLSTRIP DEF DEPR FERC ADJ.	8,316,981 2,449,668			
31 32	ENCOGEN ACQUISITION ADJ. BPA POWER EXCHANGE INVESTMENT		sum of L32 thru	293,050,941	After Production Adj. 284,728,294
33 34 35	TENASKA REGULATORY ASSET CABOT OIL REGULATORY ASSET LESS ACCUM. DEPRECIATION	229,424,000 12,491,000 (519,770,787)	1		
36 37	LESS ACCUM. AMORTIZATION NET PRODUCTION PROPERTY	(3,186,245)	<u>)</u>		
38 39 40	DEDUCT: LIBR. DEPREC. PRE 1981 (EOP)	(5,250,238)			
41 42	LIBR. DEPREC. POST 1980 (EOP) OTHER DEF. TAXES (EOP) ADJUSTMENT TO RATE BASE	(94,132,216) (17,930,541) 789,237,403)	766,823,061	Less Regulatory Assets 482,094,767
43	Plus Snoqualmie CWIP	/az,£3/, 1 03	(22,717,372)		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					INCREASE
NO.	DESCRIPTION	ACTUAL	P	ROFORMA	(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				\$ 1,177,084,685
	•			•	

Exhibit B: Power Costs Subject to PCA Sharing Example

					3	Example hd 02 - Jun 03	Bralanation or equipe
§					3	20 20 20	
4						4 -	<u>, , , , , , , , , , , , , , , , , , , </u>
ĸ	Return on Fixed RB				•	71,035,988	from Exhibit A-1 lines 11&12 - production and transmission ratebase adjusted to Rate Year
							from Exhibit A-1 lines 15,19,22-26 (557, Hydro and Other Prod. O&M, 500 KV O&M,
9	Other Fixed Costs					120,513,555	Depreciation fixed, Property tax) adjusted to Rate Year
	Subtotal Fixed Costs				s,	191,549,544	
60	onent Actual					i	***************************************
6		501	≨	illustrative est.	•	33,461,494	SAP - actual
5	Other Pwr Gen Fuel	547	€	Bustrative est.		55,009,484	SAP - actual
=	Other Elec Revenues 4560	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 - ectual
2	=	447	=	Illustrative est		(35,448,055)	SAP - actual
		585	=	Mustrative est		43 496 800	SAP - schal
	erice Design	45600047	: :	Bustrative act		(5,000,000)	SAP - actual Transmission revenues on 3rd AC. Northern Intertie. Colstrib lines
2 =			: =	llustrative est.			from Exhibit D line 35. Return on regulatory assets for PCA period
2 12							
: 00	SUBTOTAL before Adjustments			642,456.32	"	854,272,871	
6	•						
۶ ا	Adjustments:						
7	Pridence from UE-921262		=	llustrative est.	49	(2.260,152)	Prudence adj. = 3% * March Pt 2 payments; and 1.2% * Tenaska payments
; ;	Contract price adilistment		Ē	Bustrative est		(1 094.429)	Ina 42
1 8			= =	M. tofraction pet		(A. 2.1.2. A.7.8.)	from Exhibit Films 40
	Colsting availability adjustment			Mustrative est.		CONTRACTOR SOUTH	from Ewills C in 38
7 7	New resource pricing adjustment	_	₫	USTIBLING GSE		(ppp-'ppp-)	IVII LAIMA VIIVON VAIVANAMINIMAMIN
8 2	Subtotal Adjustments				•	(9,555,559)	
27	•						
8	Total allowable cost				\$	844,717,312	
8						1	
_	8		•	est. actual	•	19,110,518	Actual derivered MVN during PCA period = 1 oral load into 8 tosses Resea line rate from Exhibit A-1 line 25
8 3	Baseline Power Cost	200			,	10,406,800	
							to Exhibit C column (C). A portion of the imbalance will be allocated to firm wholesale
S	Imbalance for Sharing				•	4,752,701	customers based upon the allocation used in the most recent Docket approving rate spread.
8	positive is potential customer surchange, negative is pot	e, negative is pot	tential cu	bential customer credit			
8							
8	Company's Share		į		•	701	
37	First band - deadband	_	%00	4,752,701		4,752,701	
8	2nd Band - next		20%	•	19 (•	***************************************
ස	3rd Band - next		2	•	%	•	***************************************
\$:	4th Band greater than \$12	\$120,000,000	80	4 760 704	٠ ٠	4 752 704	to Exhibit C column (G)
÷ \$	Subsocial Company share before Cap	3		4,136,14			
3 :		1			Ŀ		to Exhibit C column (D)
2	Customer Snare (deferral account)	, and			·		

Exhibit C - Application of \$40 million Cap

set for refund or collection at that time. Example: 1 First year per draft Exhibit examples; next 3 years high power costs	(D) (E) (G) (H) (J)	Customer End Period Potential Customer Annual Share Share over Deferral Company / from share over Company Company / from share over Company Company / from share over Company Ex. B line 43 Ex. B line 41	(5.83) \$ - \$ - \$ - \$ (5.83) \$ - \$ - \$ (5.83) \$	8 5.00 \$ 5.00 \$ 25.00 \$. \$ 19.17	0 s 5.00 s 4.13 s 14.13 s 25.00 s (4.17) s 0.04 s 40.04 s	NO \$ 5.00 \$ 24.75 \$ 43.88 \$ 25.00 \$ (25.00) \$ 0.25 \$ 40.29 \$	84.2 OK \$ 43.9
set for refund or collection at that time. Example: 1 First	(0)	Imbelance for Sharing Ex. B line 33	(5.6	30.00	30.00	30.00	28

Exhibit C - Application of \$40 million Cap

PCA 9

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 secoclated with the cap are 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 set for refund or collection at that time.

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

\$ in Millions

Counter																
Customer Arnual Share Customer Arnual Share Share Customer Share Customer Share Customer Share Customer Share Company I from share Share Wio Cap Company I from Share Company I from Share Company I from Share Company I from Share Share Wio Cap Company I from Share I from I from Share I from I fr		(2)	9		(E)	۳		(9)	Œ	€		3	3	3		<u>§</u>
\$ 30.0 \$ 5.0 \$. \$ 5.0 \$. \$ 25.0 \$. \$ 5.0 \$		Imbalance fo Sharing Ex. 8 line 33	Custo	Share Share erral" (Customer Arrual Share over Cap at 99%			Company Annual Share Ex. B line 41	Potential transfer (to) / from customer	Compare on Cap at 1	. mo	d Period ompany Share		Accum. Amour Over Cap	Annual It in Amo C	Change unt over
\$ 30.0 \$ 5.0 \$. \$ 5.0 \$. \$ 25.0 \$. \$ 5.0 \$ 5 . \$ 25.0 \$ \$. \$ 25.0																
\$ (100.0) \$ (64.0) \$. \$ (51.0) \$ (51.0) \$ (36.0) \$. \$. \$. \$. \$. \$. \$. \$. \$. \$	PCA Yr #1	•	\$ 0.0	2.0	•	•	5.0	\$ 25.0	•	•	*	25.0	\$ 25.0	•	•	٠
\$ (100.0) \$ (64.0) \$. \$ (59.0) \$ (36.0) \$. \$. \$ (11.0) \$ \$ 36.0 \$ 8.0 \$. \$ (51.0) \$ 28.0 \$. \$. \$ 17.0 \$ \$ (34.0) OK \$ (51.0) \$ 5 (51.0)	PCA Yr #2	•	•	,	•	•	5.0	•	•	•	**	25.0	\$ 25.0	•	•	•
\$ 36.0 \$ 8.0 \$. \$ (51.0) \$ 28.0 \$. \$ 17.0 \$ \$ (34.0) OK \$ (51.0) \$ 51.00	PCA Yr#3	•		(64.0)	•	•	(28.0)		•	•	•	(11.0)		•	•	•
\$ (34.0) OK \$ (51.0)	PCA Yr #4		\$ 0.	8.0	•	•	51.0)		•	•	••	17.0		•	•	•
	Check	<u>ন</u>) (e.			•	51.0)				~	17.0				

8 848

8 8

8888

Exhibit C - Application of \$40 million Cap

PCA

Example: 3	es ::	Thre	Three high	ó	Wer cos	st year	13 fo	Three high power cost years followed by very low power cost year.	Ven	/ low po	wer co	ist y	ear.						٦
	(2)		<u>©</u>		(E)	E		(9)		£	ε		3		(3)		5		E
	imbalance for Sharing Ex. 8 line 33		Customer Annual Share = "Deferral" Ex. B line 43	Share Share	Customer Annual Share over Cap at 99%	End Period Customer Deferral Balance	D F F S	Company Arrual Share Ex. B line 41		Potential transfer (to) / from customer	Company share over Cap at 1%	ı	End Period Company Share		Company Accum Share w/o Cap	Accum	cum. Amou Over Cap	₹ 3.⊊	Annual Change Accum, Amount in Amount over Over Cap Cap
PCA Yr#1	\$ 30.0	•	9.0	•	•	•	5.0	\$ 25.0	•	•	•	-	2	25.0	25.0	•	•	∽	•
PCA Yr#2	\$ 100.0	\$	2 0.	•	20.8	*	89.8	\$ 36.0	•	(21.0)		0.2	4	40.2	61.0	•	21.0	•	21.0
PCA Yr#3	36.0	•	8.0	4	27.7	*	125.5	\$ 28.0	s	(28.0)	•	0.3	4	40.5	0.68	•	49.0	•	28.0
PCA Yr#4	\$ (100.0) \$	6	(64.0)	•	(35.6)	•	25.9	(36.0)	S	38.0	•	(0.4) \$		5.	\$ 53.0	•	13.0	•	(36.0)
Check	\$ 66.0	ě				5	822						*	\$					

Exhibit C - Application of \$40 million Cap PCA

(C) (D) (E) (F) (G) (H) (I) (I) (J) (K) (L) Customer Annual Customer End Period Customer Customer Cap at 1% Share Share over Company Ex. B line 33 Ex. B line 43 (30.0) \$ (5.0) \$ (20.8) \$ (89.8) \$ (36.0) \$ (2	Example: 4	9 : 4	Similar to \$ in Millions	examp	le 3,	but fort	unes a	ire reve	rsed	with 3	low cos	st Se	ars foll	Similar to example 3, but fortunes are reversed with 3 low cost years followed by a high cost year. \$ in Millions	high co	ost yea	٠	
Customer Annual Share Customer Annual Share Customer Annual Share Customer Sharing = "Deferral" Cap at 99% Balance Ex. B line 43 Ex. B line 41 Ex. B line 43 Ex. B line 41 Ex.		(2)	ê	Œ		(F)		(0)		<u>-</u>	ε		a	3		3		(X)
\$ (30.0) \$ (5.0) \$ - \$ (5.0) \$ - \$ (25.0) \$ - \$ (25.0) \$ (25.0) \$ (25.0) \$ (5.0) \$ (100.0) \$ (64.0) \$ (20.8) \$ (89.8) \$ (36.0) \$ (20.0) \$ (40.2) \$ (40.2) \$ (61.0) \$ (36.0) \$ (80.0) \$ (27.7) \$ (125.5) \$ (28.0) \$ (28.0) \$ (20.3) \$ (40.5) \$ (68.0) \$ (89.0) \$ (100.0) \$ (40.1) \$ (25.8) \$ 36.0 \$ (36.0) \$ (0.4 \$ (40.1) \$ (53.0) \$		Imbalance for Sharing Ex. 8 line 33	Customer Annual Share = "Deferral" Ex. B fine 43	Cus Cap:		End Perior Customer Deferral Balance		mpany ali Share Biline 41	Pote transfi / fr		Company share over Cap at 1%		l Period mpeny ihare	Company Accum Share w/o Cap		i. Amourr er Cap	Annus t in Am	Annual Change in Amount over Cap
\$ (100.0) \$ (64.0) \$ (20.8) \$ (89.8) \$ (36.0) \$ 21.0 \$ (0.2) \$ (40.2) \$ (61.0) \$ \$ (36.0) \$ (8.0) \$ (27.7) \$ (125.5) \$ (28.0) \$ 28.0 \$ (0.3) \$ (40.5) \$ (88.0) \$ \$ 100.0 \$ 64.0 \$ 35.8 \$ (25.8) \$ 36.0 \$ (36.0) \$ 0.4 \$ (40.1) \$ (53.0) \$	PCA Yr #1	•		*		\$ (5.0	8	(25.0)	-			•	(25.0)		9	'	4	
\$ (36.0) \$ (8.0) \$ (27.7) \$ (125.5) \$ (28.0) \$ 28.0 \$ (0.3) \$ (40.5) \$ (89.0) \$ \$ 100.0 \$ 64.0 \$ 35.6 \$ (25.8) \$ 36.0 \$ (36.0) \$ 0.4 \$ (40.1) \$ (53.0) \$	PCA Yr#2	•		•				(36.0)	••	21.0	\$ (0.2	*	(40.2)	•	•	(21.0		(21.0)
\$ 100.0 \$ 64.0 \$ 35.6 \$ (25.9) \$ 36.0 \$ (36.0) \$ 0.4 \$ (40.1) \$ (53.0) \$	PCA Yr #3	•	••	•	(27.72		\$	(28.0)	•	28.0	\$ (0.3	8	(40.5)	•	•	(49.0	•	(28.0)
	PCA Yr #4		•	•			<u>\$</u>	36.0	•	(36.0)		•	(40.1)		*	(13.0)	9	36.0

Assets	
Regulatory	
Exhibit D:	

Interest Amort Balance Amortization Ratebase (AMA) 7.30% R. 7.20% R. 7.2	_						7 4 7 0	furt fresh	0		T CO
2000 5 12,588,000 720,000 12,986,000 124,9	ις.	Cabot Buyout		,	,		47 :	unc-inc	return 7 90%		
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Jul-03 Jun-04 PCA#2 \$ (18,449,120) \$ 277,332,698 \$20,245,287 \$ Jul-04 Jun-05 PCA#3 \$ (21,818,120) \$ 257,246,578 \$18,779,000 \$ Jul-05 Jun-06 PCA#4 \$ (25,176,620) \$ 233,699,083 \$17,060,033 \$	ဂ္ဂ			20-IDC	20-100	5		•	46.1,006,16.1	•	10,40
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Un-06 PCA#4 \$ (25,176,620) \$ 233,699,083 \$17,060,033 \$	37			Jul-04	Jun-05	PCA#3		\$	\$ 18,779,000	⇔	28,890,770
	38			Jul-05	Jun-06	PCA#4	\$ (25,176,620)	\$ 233,699,083	\$17,060,033	4	26,246,205

	Adjustments
	- Contract
PCA'O	Exhibite

Estimated costs from hypothetical PCA period

Observation NUO Gen. NUO Displ. Total Cost \$ Rate Change Displ.					_	TCA Period				
Charge Charge Charge Charge Charge Charge Cha			Limit - Rate or							Adient for
CONTRACTS CONT		;	Total Cost per	Generation	NUG Gen.	NUG Displ.		Actual	2	Positive
Control Colored Colo		Note	UE-011570	MMP	MAN		Total Cost \$	Rate	Chempe	Differences
Extract Control Cont	- 1)	
Exchange Free State Link \$ 2.817 \$ 394,694 \$ 1,020 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0	8 Baker Replacement	Exchance			0.000					
PAY ANNER 7 Return Prove	•	Rate Limit	8 67.00	21/12						
Post Service Post	•	Rate Link		384 834			000.000	00.70	000	42
CSPE Micholambial Contentwiden State S		Actual Cost					9 10,032,000	\$ 20.30	5 0.13	48,434
MAC-Columbia		Rate Limit		92 170			222 000			
MACContinuities	- 1	¥¥.					000,000	- 2	(0.00)	•
WHE C Firm Contract-Comment and CEA-E Viv. With Contract-Comment and CEA-E Viv. WHE C Firm Contract-Comment and CEA-E Viv.		¥								
Web Firm Contract Chemical Explanated Light Contract Chemical Explanated Light Contract Chemical Explanated Light Contract L	•	ž								
WARPO Entroted-Energy	•	1								
Experimental Editorium Continued 15 yr Actual Cost A	•	Actual Cost	3				\$ 28,732,000			350,000
Note Exchange Exchange Court	•	Activation								
WWP Contract 5 yr Achiel Contract 5 yr		Actival								
NAME	. —	Rate I Imb		100 OC						
WAVP Contract 15yr Strong Action Strong		Actual Cont					3 2,500,000	1	120	47,000
FOREE Exchange Storage Accided Exchange Stor		thorach 12/31/70								
Committee Comm	•	Embana								
Comman C	•	CACINETING								
Commonweight Comm	•		50 G	£.			\$ 52,000	\$0.0€	•	
NUG Real Linit 10	•		74.87	32,692	· ·		\$ 2,448,000	\$ 74.86	\$ 0.00	480
Columnic	•	NUG Rate Limit	5 61.01	436,000	436,000	•	\$ 26,639,600	\$ 61.10	8000	37.941
Victorial Cogenia 2 Winter Victorial Cogenia Victorial Cogenia 2 Winter Victorial Cogenia 2 Win	•	NOG Referred	5.2	281,000	181,000	100,000	\$ 12,279,700	\$ 43.70	•	
Perf Townsend Hydro Russ Limit \$ 55.30 222,000 132,000 12,629,600 \$ 55.30 \$ - \$ \$	•	NCG Rate Limit	86.00	330,000	330,000	•	\$ 22,011,000	\$ 96.70	\$ 0.70	229 552
Post Course of Cook Paris Limit S 28.21 2,894 S 29.21 S	•	NCG Referring	\$5.30	232,000	132,000	100,000	\$ 12,829,600	\$ 55.30	•	
Columbia Cost Actual Cost	•	Rate Limit	\$ 28.21	2,694			28 000	\$ 2821		
Spokene MSW Rate Limit 8 17.54 141,552 85,000 85,000 8 54,831,200 8 62,40 8 0.04 8 9 62,000 8 54,831,200 8 62,40 8 0.04 8 9 62,000 8 54,831,200 8 62,40 8 0.04 8 9 62,000 8 54,831,200 8 62,40 8 0.04 8 9 62,000 8 54,831,200 8 52,000	•	Actual Cost								
Nucle Rate Limit Second Se	•	Rate Limit	\$ 87.54	141,552			\$ 12 397 000	\$ 87.55	700	383
OF Sumes Summer	•	NUG Rate Limit	20.20	000,099	963,000		2 4 63 2 200			
OF Syglicowicz Ruis Limit \$ 51.37 1,421 Muse Resista (eact, Reg, Amort.) Ruis Limit \$ 51.37 1,421 Muse Resista (eact, Reg, Amort.) Ruis Limit \$ 1.858,028 1,658,026 100,000 \$ 62,069,488 3 1.70 \$ (0.14) \$ (0.14) \$ (0.01)		NCG Rate Limit	\$ 59.20	481,000	361 000		\$ 27.204.200	96.40	R	marc/c
OF Tenests (acd. Reg. Amolt.) NUG Rais Limit \$ 31.84 1,959,028 1,659,028 100,000 \$ 62,069,488 \$ 31.70 \$ (0.14) \$ (0.14) \$ (0.14) \$ (0.14) \$ (0.14) \$ (0.14) \$ (0.14) \$ (0.14) \$ (0.14) \$ (0.14) \$ (0.14) \$ (0.14) \$ (0.01) \$ (0.14)	•	Rate Cink	\$ 51.37	1.421				20.40	•	•
OF Twin Falls Rule Limit \$ 75.00 69,955 \$ 75.00 \$ 75.0	٠.	NUG Refe Limit	31.84	1.958.078	1 ASA IDA	000 00t		<u> </u>		•
Comparison of the Contract of the Cost State Limit State Cost State Limit State Cost		Rate Limit	75.00	556.00	O Tarick	000,001	4 62,009,400	2 5 7 7 7	6.14	•
Stookumchuck TOTAL Reverse sign and enter on Exhibit B line 22 \$ Notes: Exchange: No Adjustment. Either power for power exchage at zero cost or flood control for power at zero cost. NA: No Adjustment. Zero cost contracts. Rate Limit: Calculate actual rate for PCA period, compare with contract rate assumed in revenue requirements; multiply rate change (if positive) times contract generation. Total Cost: No Adjustment. Either no rate specified in contract, or rate besed upon DJ market index, or as agreed.	•		25.00	12.542			C30,042,C	3 5		•
Notes: Reverse sign and enter on Exhibit B line 22 S Reverse sign and enter on Exhibit B line 22 S Exchange: No Adjustment. Either power for power exchage at zero cost or flood control for power at zero cost. NA: No Adjustment. Zero cost contracts. Rate Limit: Calculate actual rate for PCA period, compare with contract rate assumed in revenue requirements; multiply rate change (if positive) times contract generation. Actual Cost: No Adjustment. Either no rate specified in contract, or rate besed upon DJ market index, or as agreed.		Artist Cas					200	20.00	(0.00)	
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Notes: Exchange: No Adjustment. Either power for power exchage at zero cost or flood control for power at zero cost. NA: No Adjustment. Zero cost contracts. Rate Limit: Calculate actual rate for PCA period, compare with contract rate assumed in revenue requirements; multiply rate change (if positive) times contract generation. Actual Cost. No Adjustment. Either no rate specified in contract, or rate besed upon DJ market index, or as agreed.									•	1,084,429
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Rate Limit: Calculate actual rate for PCA Actual Cost: No Adjustment. Either no m Total Cost: I law heard store that actual costs.		gets.								
Actual Cost: No Adjustment, Either no na		r PCA period, compar	 with contract rate 	assumed in reven	we requirement	S; multiply rate	change (if positi	ve) times co	office constant	5
47 Total Cast Indiana bateleand in male many bacome and account of the first of the cast	_	if no rate specified in	contract, or rate be	sed upon DJ mark	et index or as a	Oreed.				i
	47 Total Cost 1 imit heard men total	South to rate most become	Acces benefit and	Man 1- 1- 0- 1- 1- 1- 1- 1- 1- 1- 1- 1- 1- 1- 1- 1-						

NUO Rate Linkt: Calculate actual rate monthly assuming actual availability with no displacement; compare with average sessonal rate-year contract rate (also without displacement); **å** å

PCA Exhibits A-G v3.xts

CONFIDENTIAL

Exhibit F - Colstrip Availability Adjustment

Row						
4	Part 1. Colstrip Ed	quivalent Avail	ability during	PCA period -12 N	nontn	
5						
6		<u>182</u>	<u> 3&4</u>			
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	
20						
₂ 21	12 mo Average	85.00%	56.59%	69.47%		
22	Weighted by days in the	e month		Weighted by Pl	ant Capacity and	days/month
23						
24						
25	Part 2. Calculate a	annual availab	ility penalty ra	atio		
26	Less than 70%		yes, penalty asse			
27	Actual Ratio	69.47%	, , ,			
28	Target Ratio	75.00%	per Collaborativ	e agreement		
29	Penalty	-5.53%	•			
30						
31						
32	Penalty Ratio =	-7.37%	= per	nalty -5.53%		
33	, silaky itaki		-		er Collaborative	agreement
34						
35						
	Part 3. Calculate	Annual Coletri	. Eived Cost	Penalty		
36	Part 3. Calculate	Aimuai Coistii	rixed Cost	Citalty		
37	T-4-1 Eb 4 O 4 6	70 969 054	from Evhibit A	3 (Colstrip Total Reve	nue Requiremen	t)
38	Total Fixed Cost \$	78,868,054	HOIH EXHIBIT A-	o (Colstilly Total Neve	ilas i togali silisii	-,
39	Donalty Potio =	-7.37%				
40	Penalty Ratio =	45.040.479	A. C.Likia D fir	22		

to Exhibit B line 23

41 Penalty \$

\$

(5,812,478)

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]	
² 3	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 <i>ノ</i>		
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	Nav-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

D		عد مدر	,				
Row	For New Decourage with a To-		. 41	0 Vaara			
3	For New Resources with a Ter	ms Longe	tnan	2 Tears			
4 5	Name	Cample 24	alaa				
		Sample ne					
6	Description	Combined					
7		In-service	date Ja	nuary 2003			
8							
9							
10	PCA Period	July 2002 -	- June 2	2003			
11							
13	Total Variable Component Actu	ادر					
14	Steam Oper. Fuel	501	S	_			
15	Other Pwr Gen Fuel	547	•	33.000.000			
16		45600012, 1	В				
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	Andreal Maniable Octo						
25 26	Actual Variable Cost	(\$/MWh)		\$45.000			
20 27	Compare with Baseline Rate						
21 28	Baseline Power Cost Rate	(\$/MWh)		644 499			
29	Desenting towar Dost Mate	(Aumaais)		\$44.482			
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 ra	ate is lower th	nan acti	ual variable cost			
35	-						
36	Adjustment Rate	(\$/MWh)		-\$ 0.518			
37	Adjustment volume	(MWh)		750,000			