

**EXHIBIT NO. ___(KJB-1T)
DOCKETS UE-17 ___/UG-17 ___
2017 PSE GENERAL RATE CASE
WITNESS: KATHERINE J. BARNARD**

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

**WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,**

Complainant,

v.

PUGET SOUND ENERGY,

Respondent.

Docket UE-17 ___

Docket UG-17 ___

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

KATHERINE J. BARNARD

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 13, 2017

PUGET SOUND ENERGY

**PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF
KATHERINE J. BARNARD**

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1 **PUGET SOUND ENERGY**

2 **PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF**
3 **KATHERINE J. BARNARD**

4 **I. INTRODUCTION**

5 **Q. Please state your name and business address.**

6 A. My name is Katherine J. Barnard, and my business address is 10885 N.E. Fourth
7 Street, Bellevue, Washington 98004. I am employed by Puget Sound Energy
8 (“PSE”) as the Director, Revenue Requirements and Regulatory Compliance.

9 **Q. Have you prepared an exhibit describing your education, relevant**
10 **employment experience, and other professional qualifications?**

11 A. Yes. It is the First Exhibit to my Prefiled Direct Testimony, Exhibit No. ____ (KJB-
12 2).

13 **Q. Please summarize the purpose of your testimony.**

14 A. My testimony and exhibits in this proceeding will address the results of operations
15 and the associated base rates revenue deficiency for electric operations. I will also
16 discuss the results of the now four -year rate plan and PSE’s attainment of cost
17 efficiencies as shown in the required reporting to the Commission that has
18 occurred throughout the rate-plan period. Additionally, I will demonstrate that
19 absent the annual K-factor escalation through the rate plan, PSE would have
20 continued to experience attrition and earnings below its authorized rate of return
21 despite the measures PSE has taken to achieve additional cost savings. I will
22 outline how the revenue requirement will be determined under PSE’s proposed

1 Expedited Rate Filing (“ERF”) and Electric Cost Recovery Mechanism
2 (“ECRM”). Finally, I will respond to certain aspects of the Commission’s
3 Investigation of coal-fired generating unit decommissioning and remediation costs
4 in UE-151500.

5 **Q. Are you sponsoring any exhibits?**

6 A. Yes, I am sponsoring Exhibit No. ____ (KJB-2) through Exhibit No. ____ (KJB-9).

7 **II. SUMMARY OF PROPOSED ELECTRIC REQUESTED**
8 **REVENUE**

9 **Q. Please summarize PSE’s requested overall increase to electric revenue.**

10 A. PSE is requesting an overall revenue increase for electric of \$86.7 million as
11 supported in the Prefiled Direct Testimony of Jon A. Piliaris, Exhibit
12 No. ____ (JAP-1T).

13 **Q. How will PSE change its rates to achieve these changes in revenue**
14 **requirement?**

15 A. As discussed by Mr. Piliaris, PSE’s current rate structure is recovering its base
16 revenue in multiple rate schedules. The following provides a summary:

17 Delivery Revenue:

- 18 • Base Rates – 2011 general rate case (from UE-111048 and
19 UG-111049)
- 20 • Schedule 141 – Expedited Rate Filing (from UE-130137
21 and UG-130138)

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- Schedule 142 – Decoupling, K-Factor and Earnings Sharing (from UE-121697 and UG-121705 and multiple subsequent Schedule 142 filings)

Power Cost and Production Revenue:

- Base Rates (from 2011 general rate case in UE-111048 and UG-111049)
- Schedule 95 (from UE-130617 and UE-141141 and UE-161135)

Because PSE’s base revenues are being recovered in multiple rate schedules, the overall rate increase for electric will be achieved by changing all of the base and adjusting rate schedules listed above. In its direct filing, PSE has not requested to change all of the rate schedules listed below. Rather, changes to certain of the schedules will be filed at the same time as the compliance filing in this case. The following is a summary of how PSE is proposing to change its base and adjusting rate schedules in this proceeding or at the time of compliance:

- Base rates will be increased for the difference between the revenue requirement in the 2011 general rate case and the revenue requirement in this proceeding.
- Schedule 141 will be set to zero.
- Schedule 142 will be lowered to remove the portion that is recovering the K-factor that increased PSE’s rates during the stay-out period.
- Schedule 95 will be set to zero.

1 **Q. Does your testimony cover the changes to all of the base and adjusting rate**
2 **schedules listed above?**

3 A. No. My testimony will focus only on determining PSE's revenue requirement. I
4 will discuss the amount that base rates are deficient (as opposed to the overall rate
5 change) based on this revenue requirement. The Prefiled Direct Testimony of Jon
6 A. Piliaris, Exhibit No. ___(JAP-1T), will cover the overall rate change and will
7 discuss the change to the other electric rate schedules.

8 **III. 2013 MULTI-YEAR RATE PLAN**

9 **Q. Please describe the Rate Plan.**

10 A. The Rate Plan implemented several innovative ratemaking mechanisms that,
11 together, fulfilled the Washington Utilities and Transportation Commission's
12 ("WUTC" or "Commission") stated goal of breaking a recent pattern of almost
13 continuous rate cases for PSE. As the Commission observed in PSE's 2011/2012
14 general rate case ("GRC"):

15 In this connection, the Commission would be particularly
16 interested in proposals that might break the current pattern of
17 almost, continuous rate cases. This pattern of one general rate case
18 filing following quickly after the resolution of another is
19 overtaxing the resources of all participants and is wearying to the
20 ratepayers who are confronted with increase after increase. This
21 situation does not well serve the public interest and we encourage
22 the development of thoughtful solutions.¹

23 The solutions approved by the WUTC under Dockets UE-130137 and UG-130138
24 *et al.*, included an update to PSE's rates established in the 2011 GRC in an

¹ Dockets UE-111048 & UG-111049, Order 08, ¶ 507.

1 Expedited Rate Filing (“ERF”) that was limited in scope and resulted in a
2 relatively modest increase (1.6 percent) in electric rates and a slight decrease
3 (0.1 percent) in natural gas rates.

4 The Commission also approved a joint petition by PSE and the Northwest Energy
5 Coalition, seeking authority to implement full decoupling of electric and natural
6 gas delivery rates under Dockets UE-121697 and UG-121705. The decoupling
7 mechanisms approved by the Commission mean that PSE’s recovery of the fixed
8 costs it incurs for infrastructure and operations necessary to deliver power and
9 natural gas will no longer depend on the amounts of electricity and natural gas
10 that PSE sells. This removed the so-called throughput incentive and promotes
11 PSE’s more aggressive pursuit of cost-effective conservation, to which PSE
12 committed to as part of the decoupling mechanism. With the throughput incentive
13 eliminated, PSE is indifferent to sales lost as a result of the success of its
14 conservation efforts. The full decoupling mechanism approved under Dockets
15 UE-121697 and UG-121705 is the first utility-supported mechanism that is both
16 generally consistent with, and truly targeted to achieve, this key objective
17 embodied in the Commission’s 2010 Decoupling Policy Statement issued
18 November 4, 2010 under Docket U-100522.

19 The third initiative the Commission approved under Dockets UE-130137 *et al.*
20 was a rate plan that would allow modest annual increases in PSE’s rates while
21 requiring that PSE not file a general rate increase any time before April 1, 2015.
22 The rate plan was designed to give an incentive to PSE to become more efficient
23 and to implement cost-cutting measures that would benefit customers while also

1 allowing PSE a better opportunity to earn its authorized rate of return. The rate
2 plan included important protections for customers, including an earnings test that
3 requires PSE to share with customers on an equal basis any earnings that exceed
4 its authorized return during the term of the plan. Annual rate increases including
5 the recovery of PSE's decoupling deferrals were also capped at 3.0 percent.

6 **Q. What was the Commission's expectation with respect to PSE's performance**
7 **during the rate plan period?**

8 A. The Commission expected PSE to institute cost-cutting measures that would
9 allow PSE to earn its authorized rate of return and benefit customers. In
10 paragraph 163 of the Commission's Final Order in the decoupling docket, the
11 Commission stated:

12 We hope, and frankly expect, PSE to earn its authorized rate of
13 return and do so by instituting effective cost-cutting measures. In
14 the long run, those savings will be captured in the Company's
15 authorized revenue requirement and the savings passed onto
16 ratepayers.

17 **Q. Did the experiment work?**

18 A. Yes, PSE last filed a GRC in 2011. The annual escalations in allowed delivery
19 revenue per customer, the K-factor, helped PSE mitigate pressures that had
20 prevented PSE from earning a fair rate of return and required PSE to file annual
21 rate cases. Through PSE's efficiency measures, the growth in expenses has
22 slowed considerably since the K-factor was approved, which benefits customers
23 and allowed PSE to agree to extend the rate plan for an additional year before
24 filing this general rate case.

1 **Q. Have there been cost efficiencies achieved by PSE during the stay out period?**

2 A. Yes, the growth rate in operating and maintenance expenses, both in terms of
 3 overall cost increase and the increase in cost per customer have been reduced
 4 significantly. The following tables, which have been provided on a semi-annual
 5 basis to the Commission as part of the rate plan compliance reporting,
 6 demonstrate that there has been a downward trend in the growth rate. The actual
 7 cost per customer has increased at a compound growth rate of only 1.2%, which is
 8 significantly lower than the historical compound growth rate PSE had experienced
 9 prior to the rate plan.

10 **Table 1. PSE Operating Expenses per Customer-combined Electric and Gas**

LINE NO.	DESCR	12ME Dec 2011	12ME Dec 2012	12ME Dec 2013	12ME Dec 2014	12ME Dec 2015	12ME Jun 2016	COMPOUND GROWTH RATE
		RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	
(\$ in thousands)								
		UG-120609	UG-130653	UG-130537	UG-150529	UG-160376	UG-130138/121705	
1	COMBINED EXPENSES:							
2	TRANSMISSION EXPENSE	\$ 9,531	\$ 19,073	\$ 19,384	\$ 21,589	\$ 19,801	\$ 20,211	
3	DISTRIBUTION EXPENSE	130,531	126,441	127,564	136,491	131,978	142,906	
4	CUSTOMER ACCOUNT EXPENSES	78,513	80,013	82,231	82,710	76,520	71,461	
5	CUSTOMER SERVICE EXPENSES	4,800	3,249	3,914	5,604	3,810	4,199	
6	ADMIN & GENERAL EXPENSE	142,745	145,172	154,517	159,194	156,849	162,080	
7	TOTAL EXPENSES	\$ 366,120	\$ 373,949	\$ 387,610	\$ 405,588	\$ 388,959	\$ 400,857	2.0%
8								
9	AVERAGE CUSTOMER COUNT	1,840,114	1,852,951	1,858,766	1,876,129	1,898,648	1,910,866	
10	ACTUAL COST PER CUSTOMER	\$ 198.97	\$ 201.81	\$ 208.53	\$ 216.18	\$ 204.86	\$ 209.78	CALCULATED 1.2%
11	2011 GROWN AT HISTORICAL RATE	\$ 198.97	\$ 206.45	\$ 214.22	\$ 222.28	\$ 230.64	\$ 239.32	COMBINED ERF 3.8%

12 **Q. Is this growth rate in expenses in line with the stretch goals established in the**
 13 **rate plan for the stay out period?**

14 A. Yes. The escalation factors utilized in the rate plan for non-production related
 15 operating expenses were based on the forecasted CPI less a productivity factor.
 16 The CPI was forecasted to be 2.4% during the rate plan period, and with the 50
 17 basis point reduction for assumed productivity improvements, it resulted in an

1 estimated 1.9% escalation rate which was a significant reduction from the 3.8%
2 escalation rate that had been approved in the 2006 to 2011 period.

3 **Q. Is this slowing in growth in costs providing benefits to customers?**

4 A. Yes, as reflected on line 11 of Table 1, based on PSE's historical compound
5 growth rate in expenses of 3.8% per year, the \$198.97 expense per customer
6 based on calendar year 2011 results would have been expected to grow to \$239.32
7 per customer on a combined basis. However, as shown on line 10, actual expenses
8 per customer on a combined basis through June 2016 were \$209.78 per customer
9 for a compound annual growth rate of 1.2%. This compares favorably to actual
10 national CPI increases during this time period which was 1.5% over the 2011
11 through June 2016 period² and the actual regional CPI increase which was 2.1%
12 for the same period for the Seattle-Tacoma-Bremerton area.³

13 **Q. Do these trends apply equally to both gas and electric operations when**
14 **reviewed separately?**

15 A. Yes, there has been a slowing in operating expense growth compared to the 2006
16 to 2011 period for both gas and electric operations; however, due to changes in
17 the allocation of common costs between the two services, the growth in electric
18 operation expenses is higher and natural gas is lower. The growth in electric and
19 gas operating expenses are shown in the following tables.

² Bureau of Labor Statistics CPI table series CUUR0000SA0.

³ http://www.bls.gov/regions/west/data/consumerpriceindex_seattle_table.pdf

Table 2. Electric Operating Expense per Customer Trending

LINE NO.	DESCR	12ME Dec 2011	12ME Dec 2012	12ME Dec 2013	12ME Dec 2014	12ME Dec 2015	12ME Jun 2016	COMPOUND GROWTH RATE
		RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	
(\$ in thousands)								
		UE-120608	UE-130652	UE-140536	UE-150528	UE-160375	UE-130137/121697	
1	<u>ELECTRIC EXPENSE:</u>							
2	TRANSMISSION EXPENSE	\$ 9,481	\$ 19,058	\$ 19,356	\$ 21,589	\$ 19,801	\$ 20,211	
3	DISTRIBUTION EXPENSE	78,245	74,863	77,322	84,585	82,427	90,207	
4	CUSTOMER ACCOUNT EXPENSES	48,141	49,221	50,570	51,079	48,055	45,764	
5	CUSTOMER SERVICE EXPENSES	3,720	2,032	2,090	2,576	2,145	2,329	
6	ADMIN & GENERAL EXPENSE	96,362	99,265	106,511	110,332	109,690	113,678	
7	TOTAL EXPENSES	\$ 235,949	\$ 244,439	\$ 255,849	\$ 270,161	\$ 262,119	\$ 272,188	3.2%
8								
9	AVERAGE CUSTOMER COUNT	1,083,403	1,089,296	1,085,381	1,091,517	1,103,635	1,110,578	
10	ACTUAL COST PER CUSTOMER	\$ 217.79	\$ 224.40	\$ 235.72	\$ 247.51	\$ 237.51	\$ 245.09	CALCULATED 2.7%
11	2011 GROWN AT HISTORICAL RATE	\$ 217.79	\$ 228.00	\$ 238.69	\$ 249.89	\$ 261.61	\$ 273.88	ERF 4.7%

Table 3. Natural Gas Operating Expense per Customer Trending

LINE NO.	DESCR	12ME Dec 2011	12ME Dec 2012	12ME Dec 2013	12ME Dec 2014	12ME Dec 2015	12ME Jun 2016	COMPOUND GROWTH RATE
		RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	RESTATED RESULTS OF OPERATIONS	
(\$ in thousands)								
		UG-120609	UG-130653	UG-130537	UG-150529	UG-160376	UG-130138/121705	
1	<u>GAS EXPENSE:</u>							
2	TRANSMISSION EXPENSE	\$ 50	\$ 15	\$ 28	\$ 0	\$ -	\$ -	
3	DISTRIBUTION EXPENSE	52,286	51,579	50,242	51,906	49,551	52,699	
4	CUSTOMER ACCOUNT EXPENSES	30,372	30,792	31,661	31,631	28,465	25,697	
5	CUSTOMER SERVICE EXPENSES	1,080	1,217	1,824	3,028	1,665	1,870	
6	ADMIN & GENERAL EXPENSE	46,384	45,908	48,006	48,862	47,159	48,402	
7	TOTAL EXPENSES	\$ 130,171	\$ 129,511	\$ 131,760	\$ 135,427	\$ 126,840	\$ 128,669	-0.3%
8								
9	AVERAGE CUSTOMER COUNT	756,711	763,655	773,385	784,612	795,013	800,288	
10	ACTUAL COST PER CUSTOMER	\$ 172.02	\$ 169.59	\$ 170.37	\$ 172.60	\$ 159.54	\$ 160.78	CALCULATED -1.5%
11	2011 GROWN AT HISTORICAL RATE	\$ 172.02	\$ 175.77	\$ 179.61	\$ 183.53	\$ 187.53	\$ 191.62	ERF 2.2%

Q. What is driving the difference in allocation of common costs between gas and electric operations?

A. Roughly 75% of common costs are allocated between gas and electric based on the four-factor allocation discussed later in my testimony. The four-factor allocation is calculated using the ratio of 1) customers, 2) labor, 3) non-labor transmission and distribution (“T&D”) expense, and 4) net plant. Because of increases in electric rate base and the number of employees supporting electric operations, the four-factor allocator has been increasing toward electric—from

65.95% in 2011 to 68.26% by June 2016. There has been a corresponding decrease in the four-factor allocator on the gas side, which moved from 34.05% in 2011 to 31.74% by June 2016. This shift alone has resulted in \$3.2 million of cost being shifted from gas operations to electric operations during this period. Also, the shift in the four-factor has increased electric rate base by more than \$7.0 million and decreased gas rate base by the same amount. This is demonstrated in the following table:

Table 4. Change in Four-Factor Common Allocator

LINE NO.	DESCRIPTION	TOTAL JUN 2016 COMMON USING 4-FACTOR	USING 2011 4-FACTORS		USING JUNE CBR 4-FACTOR		DIFFERENCE	
			ELECTRIC	GAS	ELECTRIC	GAS	ELECTRIC	GAS
1	COMMON COSTS							
2	ADMIN & GENERAL EXPENSE	82,266,997	54,255,085	28,011,913	56,147,226	26,119,772	1,892,141	(1,892,141)
3	DEPRECIATION/AMORTIZATION	22,250,990	14,674,528	7,576,462	15,186,301	7,064,689	511,773	(511,773)
4	AMORTIZATION	29,801,610	19,654,162	10,147,448	20,339,599	9,462,011	685,437	(685,437)
5	OTHER OPERATING EXPENSES							
6	TAXES OTHER THAN INCOME TAX	4,641,882	3,061,321	1,580,561	3,168,084	1,473,797	106,763	(106,763)
7	GRAND TOTAL	138,961,479	91,645,096	47,316,384	94,841,210	44,120,270	3,196,114	(3,196,114)
8								
9	RATE BASE							
10	COMMON PLANT	303,688,330	200,282,454	103,405,876	207,267,285	96,421,045	6,984,832	(6,984,832)
11								
12	4-FACTOR RATES							
13	PERCENT TO ELECTRIC		65.95%		68.25%			
14	PERCENT TO GAS		34.05%		31.75%			
			100.00%		100.00%			

Q. Did PSE’s customers benefit during the rate plan period from these efficiencies?

A. Yes, through the earnings sharing mechanism in place during the rate plan period, customers received 50% of any earnings above PSE’s authorized rate of return. In 2014 natural gas operations earned above the 7.77% authorized rate of return on a Commission basis which triggered a sharing of \$1.3 million⁴. In 2015, both gas and electric operations exceeded the threshold when viewed on a Commission

⁴ Page 3 of the cover letter filed on March 31, 2015 in WUTC Docket No. UG-150525.

1 basis which resulted in a sharing of earnings of \$11.9 million⁵ for electric
2 operations and \$5.5 million⁶ for natural gas operations

3 **Q. Did PSE earn its overall authorized rate of return and return on equity**
4 **during the stay out period?**

5 A. Only in 2015, on a Commission basis, did PSE on a total company basis earn its
6 authorized rate of return and return on equity.

7 When reviewed over the course of the entire stay-out period, even with the annual
8 escalation factors and PSE's cost efficiencies, prior to any earnings sharing PSE
9 earned on average a combined rate of return of 7.79% and a combined return on
10 equity of 9.59%. After earnings sharing, these combined results drop to 7.73% for
11 rate of return, which is under PSE's authorized rate of return and 9.47% for return
12 on equity. These are below PSE's authorized rate of return of 7.77% and its
13 authorized return on equity of 9.80%.

⁵ Page 2 of the cover letter filed on March 31, 2016 in WUTC Docket No. UE-160367.

⁶ Page 2 of the cover letter filed on March 31, 2016 in WUTC Docket No. UG-160368.

Table 5. Rates of Return and Return on Equity on a Commission Basis

Results on a Commission Basis						
Period	Electric		Gas		Combined	
	Rate of Return	Return on Equity	Rate of Return	Return on Equity	Rate of Return	Return on Equity
Dec-07	8.13%	9.89%	7.34%	8.07%	7.90%	9.36%
Dec-08	6.39%	5.94%	6.52%	6.32%	6.43%	6.05%
Dec-09	6.11%	5.63%	6.10%	5.61%	6.11%	5.63%
Dec-10	6.07%	5.57%	6.24%	5.92%	6.12%	5.67%
Dec-11	6.62%	6.98%	6.78%	7.30%	6.67%	7.07%
Dec-12	7.14%	8.11%	7.46%	8.78%	7.22%	8.28%
Dec-13	7.56%	9.06%	7.34%	8.62%	7.51%	8.96%
Dec-14*	7.74%	9.44%	7.87%	9.71%	* 7.77%	9.50%
Dec-15*	8.05%	10.25%	* 8.17%	10.49%	* 8.08%	10.31%
2013 - 2015 Avg	7.78%	9.58%	7.79%	9.61%	7.79%	9.59%

* Represents ROR and ROE Before Earnings Sharing

Q. Would PSE have earned its authorized rate of return during this period absent the application of the annual escalations to electric and gas operations that were an essential element of the rate plan?

A. No, PSE would not have earned its authorized rate of return or its return on equity in any of the rate plan years had the annual escalation factors not been applied. The following table provides a comparison of PSE’s Commission Basis Report (“CBR”) results for the three-year period of calendar year 2013 through calendar year 2015, and the impact of removing the revenues associated with the annual K-factor increases approved as part of the Decoupling mechanism in Dockets UE-121697 and UG-121705.

Table 6. Comparison of CBR Overall Rate of Return

Conversion Factor	0.620346		0.621335	
	December 2013 CBR Electric		December 2013 CBR Gas	
	Filed	w/o K-Factor	Filed	w/o K-Factor
Restated Net Operating Income	\$400,237,971	\$394,773,659	\$121,284,724	\$118,730,333
Restated Rate Base	\$5,295,557,479	\$5,295,557,479	\$1,651,590,190	\$1,651,590,190
Variance NOI from Filed		(\$5,464,312)		(\$2,554,391)
Normalized Overall Rate of Return	7.56%	7.45%	7.34%	7.19%
Sharing	\$0	\$0	\$0	\$0
	December 2014 CBR Electric		December 2014 CBR Gas	
	Filed	w/o K-Factor	Filed	w/o K-Factor
Restated Net Operating Income	\$411,798,682	\$388,347,491	\$131,799,123	\$119,988,840
Restated Rate Base	\$5,321,737,695	\$5,321,737,695	\$1,675,371,023	\$1,675,371,023
Variance NOI from Filed		(\$23,451,191)		(\$11,810,283)
Normalized Overall Rate of Return	7.74%	7.30%	7.87%	7.16%
Sharing	\$0	\$0	(\$1,305,894)	\$0
	December 2015 CBR Electric		December 2015 CBR Gas	
	Filed	w/o K-Factor	Filed	w/o K-Factor
Restated Net Operating Income	\$420,761,238	\$384,779,701	\$139,397,960	\$121,297,502
Restated Rate Base	\$5,224,753,571	\$5,224,753,571	\$1,706,005,751	\$1,706,005,751
Variance NOI from Filed		(\$35,981,537)		(\$18,100,458)
Normalized Overall Rate of Return	8.05%	7.36%	8.17%	7.11%
Sharing	(\$11,927,122)	\$0	(\$5,505,334)	\$0

1 Table 6 demonstrates that absent the K-factor adjustments, which were applied
2 annually, PSE would have continued to under-earn its authorized rate of return
3 throughout the stay-out period by 30 to 60 basis points.

4 **Q. Was the rate plan a success?**

5 A. Yes, the rate plan was a success. Through PSE's achieved efficiencies and the K-
6 factor adjustments, PSE managed its costs and spending, which benefits
7 customers. As a result, PSE was able to improve its earnings and earn its
8 authorized rate of return on a combined basis in 2015 for the first time since 2006,
9 while lowering the burden on the Commission and parties of nearly annual GRCs.
10 In contrast, absent the Commission approved rate plan, PSE would have likely
11 filed at least one, if not two, GRCs between 2012 and 2016.

12 **IV. REVENUE REQUIREMENTS**

13 **A. Exhibit No. (KJB-3) Base Rates Revenue Requirement Deficiency**

14 **Q. Would you please explain Exhibit No. ___(KJB-3)?**

15 A. Exhibit No. ___(KJB-3) presents the calculation of the electric base rate revenue
16 deficiency based on the pro forma and restated test period. It also shows the
17 overall cost of capital and the electric conversion factor. The following are
18 descriptions of the individual pages in Exhibit No. ___(KJB-3).

19 **Electric Base Rates Revenue Requirement Deficiency**

20 The overall electric base rate revenue requirement deficiency is shown on page
21 one of Exhibit No. ___(KJB-3). The schedule shows the test period pro forma and

1 restated rate base, line 1, rate of return, line 2, operating income requirement,
2 line 4 and base rates revenue requirement deficiency, line 13.

3 Based on \$5,097,962,433 invested in rate base, a 7.74% rate of return⁷ and
4 \$394,582,292 of pro forma base rates operating income, PSE has an overall base
5 rates revenue requirement deficiency for electric revenues of \$149,061,986. After
6 allocation to wholesale and special contract customers, the base rates deficiency
7 attributable to retail customers is \$148,655,896.

8 **Cost of Capital Electric and Gas**

9 Page two of Exhibit No. ____ (KJB-3) reflects the proposed capital structure for
10 PSE during the rate year and the associated costs for each capital category. The
11 capital structure and costs are presented in the Prefiled Direct Testimony of
12 Brandon Lohse, Exhibit No. ____ (BJL-1T). The rate of return is 7.74 percent and
13 6.69 percent net of tax. Please see the Prefiled Direct Testimony of Brandon
14 Lohse, Exhibit No. ____ (BJL-1T), for a discussion of the components of the cost
15 of debt, including the addition of costs of the facility supporting energy hedging
16 which was previously included in PSE's Power Cost Adjustment ("PCA")
17 mechanism and is currently included in PSE's Purchased Gas Adjustment
18 ("PGA") mechanism. These costs have been included in PSE's cost of capital as
19 they will no longer be tracked in PSE's PCA mechanism pursuant to the
20 settlement agreement approved in Order No. 11 in Docket UE-130617 ("PCA
21 Settlement"). Additionally, in PSE's next PGA filing for rates effective November

⁷ The 7.74% rate of return is proposed by PSE witness Mr. Brandon J. Lohse in his prefiled direct testimony, Exhibit No. ____ (BJL-1T).

1 1, 2017, PSE will only include two months of recovery of these costs as they will
2 be included in PSE's overall cost of capital from this proceeding.

3 **Electric Conversion Factor**

4 Page three of Exhibit No. ___(KJB-3) provides the electric conversion factor that
5 is used to adjust the electric net operating income deficiency for revenue sensitive
6 items and federal income tax to determine the total electric base rates revenue
7 deficiency. The revenue sensitive items are the Washington State utility tax,
8 Washington Utilities and Transportation Commission annual filing fee, and bad
9 debts. The conversion factor used in the revenue requirement calculation is
10 0.619051 for electric operations.

11 **B. Exhibit No. (KJB-4) Electric Summary**

12 **Q. Would you please explain Exhibit No. ___(KJB-4)?**

13 A. Exhibit No. ___(KJB-4) presents the impact of each of the electric pro forma and
14 restating adjustments being made to the September 30, 2016 operating income
15 statement and rate base. The first page of Exhibit No. ___(KJB-4), the Summary
16 page, presents the unadjusted operating electric income statement and the average
17 of the monthly averages ("AMA") rate base for PSE as of September 30, 2016
18 (the test year) in the column labeled Actual Results of Operation. The various line
19 items are then adjusted by the summarized electric pro forma and restating
20 adjustments, shown in the third column. The fourth column is the adjusted results
21 of operation for the test period, and this column is used to calculate the base rates
22 revenue deficiency. In the second to last column the base rates revenue deficiency

1 is added to the adjusted test period income statement, and the impact on the
2 operating income and rate base is presented in the final column, which shows that
3 the net operating income divided by the test period rate base results in the
4 requested rate of return. The remainder of Exhibit No. ____ (KJB-4) is described
5 below.

6 Pages two through six of Exhibit No. ____ (KJB-4) present a summary schedule for
7 all of the electric pro forma and restating adjustments. The first column of
8 numbers on page two is the unadjusted net operating income for the year ended
9 September 30, 2016 and the unadjusted rate base for the same period. Each
10 column to the right of the first column represents a pro forma and/or restating
11 adjustment to net operating income or rate base. Each of these adjustments has a
12 supporting schedule, which is referenced by the page number shown in each
13 column title.

14 The second to the last column, shown on page six of the summary schedule
15 summarizes all of the adjustments and the final column shows the adjusted test
16 period results which is used to calculate the base rates revenue deficiency.

17 **C. Exhibit No. ____ (KJB-5) Electric Test Year Data**

18 **Q. Would you please explain Exhibit No. ____ (KJB-5)?**

19 A. Exhibit No. ____ (KJB-5) presents the actual financial statements for the test year
20 as follows.

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Income Statement

Page one of Exhibit No. ____ (KJB-5) presents the unadjusted electric income statements for the twelve months ending September 30, 2016, which is the test year for this general rate case filing.

Balance Sheet

Pages two through five of Exhibit No. ____ (KJB-5) present the combined end of period and AMA balance sheet for the test year.

Rate Base

Pages six through eight of Exhibit No. ____ (KJB-5) present the test year AMA rate base calculation.

Working Capital

Pages nine through eleven of Exhibit No. ____ (KJB-5) present the test year working capital calculation that is included as part of the rate base calculation.

Allocation Factors

Page twelve of Exhibit No. ____ (KJB-5) presents the allocation methods and factors used in allocating common expenditures between electric and natural gas operations.

Q. Please describe the allocation methods used on page twelve of Exhibit No. ____ (KJB-5).

A. Page twelve of Exhibit No. ____ (KJB-5) presents the allocation methods, or factors, used in allocating common expenditures between electric and natural gas.

1 Common utility plant is that portion of utility operating plant that is used for
2 providing more than one commodity, i.e., both electricity and natural gas service,
3 to customers. Common plant includes costs associated with land, structures, and
4 equipment, which are not charged specifically to electric or gas operations. PSE
5 allocates its common utility plant for electric and gas by using the four-factor
6 allocation method.

7 Common operating costs are those costs that are incurred on behalf of both
8 electricity and natural gas customers. PSE incurs common costs related to:
9 customer accounts expenses, customer service expenses, administrative and
10 general expense, depreciation/amortization, other operating expenses, and taxes
11 other than federal income tax. These common costs are allocated to electric and
12 natural gas using the most appropriate allocation method for the type of cost being
13 allocated. Allocation methods used include: (1) twelve month customer average,
14 (2) joint meter reading customers, (3) non-production plant, (4) four factor
15 allocator, and (5) direct labor allocator.

16 **Q. Are rate base and working capital calculated in the same manner as allowed**
17 **in the last general rate case?**

18 A. Yes, they have been calculated consistent with the manner approved in the 2011
19 general rate case.

20 **Q. Please explain the combined working capital calculation.**

21 A. The working capital calculation is the measure, for ratemaking purposes, of
22 investor funding of daily operating expenditures and a variety of non-plant

1 investments that are necessary to sustain ongoing operations in order to bridge the
2 gap between the time expenditures for services are required to be provided and
3 the time cost recovery occurs. The purpose of this calculation is to provide a
4 return on the funds the shareholders have invested in PSE for utility purposes that
5 have not been accounted for elsewhere or that are not otherwise already earning a
6 rate of return. The calculation is based on the average of the monthly averages of
7 the actual amounts in the asset and liability accounts for these items during the
8 test year.

9 **V. INDIVIDUAL ADJUSTMENTS**

10 **A. Exhibit No. (KJB-6) Common Adjustments**

11 **Q. Please explain the adjustments that are common to Electric and Gas**
12 **operations.**

13 A. Exhibit No. ____ (KJB-6) presents the common adjustments that apply to both
14 electric and natural gas operations. Each of the individual adjustments will be
15 addressed in testimony as indicated below.

Adjustment	Katherine J. Barnard Exhibit No. (KJB-1T)	Susan E. Free Exhibit No. (SEF-1T)	Adjustment	Katherine J. Barnard Exhibit No. (KJB-1T)	Susan E. Free Exhibit No. (SEF-1T)
6.01 Revenue and Expenses	X	X	6.12 Rate Case Expenses	X	
6.02 Temperature Normalization	X	X	6.13 Deferred Gain/Loss on Property Sales		X
6.03 Pass Through Revenue and Expense	X	X	6.14 Property & Liability Insurance		X
6.04 Federal Tax	X	X	6.15 Pension Plan		X
6.05 Tax Benefit of Pro forma Interest		X	6.16 Wage Increase		X
6.06 Depreciation Expense	X		6.17 Investment Plan		X
6.07 Normalize Injuries and Damages		X	6.18 Employee Insurance		X
6.08 Bad Debt	X		6.19 Environmental Remediation		X
6.09 Incentive Pay		X	6.20 Payment Processing Costs	X	
6.10 D&O Insurance		X	6.21 South King Service Center		X
6.11 Interest on Customer Deposits		X	6.22 Excise Tax & Filing Fee		X

An explanation of each of the adjustments I address is listed below:

Adjustment Nos. 6.01E Revenues and Expenses

This is a pro forma and restating adjustment which makes the following adjustments to the test year income statement:

- Modifies the test year revenues to the revenues that would have been collected during the test year if only the base rates from the 2011 general

1 rate case had been in effect for the whole test year. As discussed in more
2 detail above, my testimony focuses on determining and describing only
3 the change in the revenue requirement related to base rates. The Prefiled
4 Direct Testimony of Jon A. Piliaris, Exhibit No. ___(JAP-1T), covers the
5 change to the other rate schedules which include Schedule 95 Power Cost
6 Only Rate Case, Schedule 141 Expedited Rate Filing, and Schedule 142
7 Decoupling and K-factor. The following steps were taken to reflect the
8 revenue in the test year at 2011 general rate case levels:

- 9 ▪ Removed the decoupling deferrals and amortization to reflect the
10 test year revenue on a volumetric basis (Line 19).
- 11 ▪ Removed the non-tracker/rider non-base rates revenue from the
12 test year (Lines 6 through 8).
- 13 ▪ The first two steps result in the test year revenue being reflected on
14 a volumetric basis priced at 2011 general rate case base rates.
15 Therefore, the final step is to weather normalize these revenues
16 which is performed in Adjustments 6.02 discussed below.
- 17 • This adjustment also removes the credits passed back to customers
18 associated with Schedule 132 Merger Rate Credit and the credits passed
19 back to customers and the related amortization associated with Schedule
20 95A Federal Incentive Tracker.⁸ The tax impacts associated with the
21 Schedule 95A revenue and amortization are removed in the federal income
22 tax adjustment, which is Adjustment 6.04.
- 23 • Included on line 24 is the removal of the expense associated with creating
24 the regulatory liability associated with production tax credits (“PTCs”)
25 that was recorded during the test year. The income tax credit associated
26 with these PTCs is removed in the federal income tax adjustment, which is
27 Adjustment 6.04.
- 28 • Line 18 removes the accruals and true-ups recognized in the test year for
29 the estimated 2014 and 2015 earnings sharing.
- 30 • Finally, other miscellaneous adjustments to revenue are included on Lines
31 9 through 11 and 17.

32 Overall, Adjustment 6.01 decreases net operating income for electric operations
33 by \$29,139,114.

⁸ Adjustment 6.01 Lines 4, 5 and 26.

1 **Adjustment No. 6.02E Temperature Normalization**

2 As I discussed above, due to Adjustment 6.01, revenues have been reflected on a
3 volumetric basis at 2011 general rate case base rates levels for the test year.

4 Therefore, the temperature normalization adjustment is necessary to restate test
5 year delivered load and revenue to a level which would have been expected to
6 occur had the temperatures during the test year been “normal”. For electric
7 operations, this adjustment is based on the difference between the actual test year
8 Generated, Purchased and Interchange (“GPI”) load for electric and the
9 temperature normalized GPI megawatt hours (“MWH”) adjusted for system
10 losses.

11 The test year was warmer than normal requiring an adjustment to net operating
12 income to bring revenues up to what would have occurred under normal
13 conditions. The electric temperature load adjustment increases actual GPI by
14 303,891 MWh, or 281,707 MWh when adjusted for line losses. The Prefiled
15 Direct Testimony of Dr. Chun K. Chang, Exhibit No. ____ (CKC-1T), discusses
16 PSE’s weather normalization methodology and the pricing of the load adjustments
17 and their allocation to the rate classes based on the proposed rate class level
18 weather normalization methodology.

19 These adjustments increase net operating income for electric operations by
20 \$17,527,344.

1 **Adjustment No. 6.03E Pass-through Revenue and Expense**

2 This restating adjustment removes from operating revenues all rate schedules that
3 are a direct pass through of specifically identified costs or credits to customers,
4 such as the conservation rider, municipal and property taxes, the low income
5 rider, and the gain on the sale to Jefferson County PUD under Schedule 133. The
6 associated expense that is recorded in the test year for these direct pass through
7 tariffs are also removed in this adjustment.

8 The revenues and expenses associated with the electric residential exchange
9 benefits provided by the Bonneville Power Administration, the electric green
10 power program and the gas carbon offset program have also been removed along
11 with the associated amortization. The portion of the green power program
12 recorded in Account 557 power costs has been removed in the Power Cost
13 Adjustment 7.01. Finally, Renewable Energy Credit revenues passed back to
14 customers and associated amortization have been removed as well.

15 The net impact of this adjustment decreases net operating income for electric by
16 \$1,000,540.

17 **Adjustment No. 6.04E Federal Income Tax**

18 This adjustment restates test year federal income taxes (“FIT”) expense to the test
19 year for this case. This adjustment includes the removal of the income tax credit
20 associated with the PTC liability and the tax impacts associated with Schedule
21 95A that were removed in Adjustment 6.02 discussed earlier. The impact of this
22 restating adjustment decreases net operating income for electric by \$27,023,239.

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Adjustment No. 6.05E Tax Benefit of Pro Forma Interest

As in prior rate filings, PSE has included an adjustment to capture the tax benefit of pro forma interest. Please refer to the Prefiled Direct Testimony of Susan E. Free, Exhibit No. ____ (SEF-1T) for a more detailed discussion of this adjustment. The adjustment for the tax benefit of pro forma interest on electric operations increases operating income by \$53,350,177.

Adjustment Nos. 6.06 E&G Depreciation Study

This restating adjustment calculates the impact of implementing the depreciation study discussed in the Prefiled Direct Testimony of John J. Spanos, Exhibit No. ____ (JJS-1T). PSE hired Mr. Spanos and his firm, Gannett Fleming, Inc., to evaluate PSE’s depreciation rates and provide an update to the current depreciation rates, which are based on a depreciation study as of December 31, 2006. The Prefiled Direct Testimony of John J. Spanos, Exhibit No. ____ (JJS-1T), also provides an explanation in his testimony of some of the major changes between the new depreciation rates and the current depreciation rates.

To adjust the test year depreciation expense to the new depreciation rates, PSE used the relationship of the new depreciation rate for a specific asset account to the old depreciation rate for that account multiplied by the test year depreciation expense for that particular account. For example, Electric depreciation account 366 – Underground Conduit has a depreciation rate of 2.26% and the new rate is 1.77%. The relationship of the new rate to the old rate is $1.77/2.26$ or 78.41%.

The test year depreciation expense is \$14.9 million and when multiplied by

1 78.41% the new depreciation expense is \$11.7 million. The results of this
2 calculation for all asset accounts were then totaled and compared to the total
3 depreciation expense for the test period for electric, gas and common plant.
4 For electric plant and common plant allocated to electric operations and for gas
5 plant and common plant allocated to gas operations, the results of these
6 calculations are shown on lines 1-4 and 18 of these adjustments. Lines 7 through
7 15 represent the adjustment of the depreciation of asset retirement costs and
8 accretion of asset retirement obligations under the FASB⁹ Accounting Standards
9 Codification 410 (previously FASB SFAS¹⁰ 143). These categories were not
10 studied by Mr. Spanos. Amounts included on lines 7 and 14 of each adjustment
11 represent amounts where the existing depreciation rate of the underlying asset is
12 sufficient to cover the depreciation and accretion for the legal obligation. For
13 these categories, PSE has used the ratio of the depreciation rates of the underlying
14 assets, as studied by Mr. Spanos, to apply to the test year depreciation and
15 accretion for the legal obligation. Amounts included on lines 8 and 15 of each
16 adjustment represent amounts where the existing depreciation rate of the
17 underlying asset is not sufficient to cover the depreciation and accretion for the
18 legal obligation and these amounts are recognized in PSE's test year as
19 incremental expense over and above the amount of depreciation recognized
20 through application of PSE's existing depreciation rates. Because cost of removal
21 that incorporates sufficient components to cover these legal obligations is now

⁹ Financial Accounting Standards Board

¹⁰ Statements of Financial Accounting Standard

1 contained in either Mr. Spanos' studied rates or the funding mechanism I discuss
2 in more detail below, PSE no longer needs this incremental expense and is
3 therefore setting it to zero. This adjustment is exclusive of the cost of removal
4 treatment for Colstrip Units 1 and 2 that I discuss below. Lines 21 through 30 on
5 each adjustment provide the total impact on depreciation expense, current federal
6 income tax expense and net operating income accumulated depreciation, as well
7 as on accumulated deferred federal income taxes and net operating income.

8 **Q. In July 2015, the Commission initiated an investigation under Docket UE-**
9 **151500 into the decommissioning and remediation costs associated with**
10 **Colstrip Units 1 and 2, owned in part by PSE. What effect does this**
11 **investigation have on PSE's current depreciation study?**

12 A. As part of that investigation, the Commission requested that Commission Staff
13 review PSE's estimated costs associated with necessary environmental
14 remediation, other expenditures related to plant retirement, and the amount of
15 funds currently held by PSE for the purpose of decommissioning Colstrip Units 1
16 and 2. As discussed in the Prefiled Direct Testimony of Ronald J. Roberts, Exhibit
17 No. ___(RJR-1T), PSE has a 50% ownership in Colstrip Units 1 and 2. Talen
18 Montana LLC ("Talen") owns the remaining 50% and is responsible for the other
19 half of the decommissioning and remediation costs for these units. The terms of a
20 recent settlement agreement established a planned retirement date for Colstrip
21 Units 1 and 2 no later than July 1, 2022.

1 As discussed in the Prefiled Direct Testimony of Ronald J. Roberts, Exhibit
2 No. ___(RJR-1T), PSE’s current estimate of remediation and decommissioning
3 costs for Colstrip Units 1 and 2 are approximately \$109 million.

4 Historically, most regulatory commissions have required that both gross salvage
5 and cost of removal be reflected in depreciation rates. The theory behind this
6 requirement is that, since most physical plant placed in service will have some
7 residual value at the time of its retirement, the original cost recovered through
8 depreciation should be reduced by that amount. Closely associated with this
9 reasoning is the accounting principle that revenues be matched with costs and the
10 regulatory principle that utility customers who benefit from the consumption of
11 plant pay for the cost of that plant, which is often referred to as intergenerational
12 equity. The application of the latter principle also requires that the estimated cost
13 of removal of plant be recovered over its life.

14 PSE considers the cost of decommissioning and remediation to include two
15 categories of costs: (1) Non-Asset Retirement Obligation cost of removal (“cost
16 of removal”), and (2) Asset Retirement Obligations (“AROs”). *Cost of removal*, is
17 defined in the Uniform System of Accounts as follows:

18 The cost of demolishing, dismantling, tearing down or otherwise
19 removing electric plant, including the cost of transportation and
20 handling incidental thereto. It does not include the cost of removal
21 activities associated with asset retirement obligations that are
22 capitalized as part of the tangible long-lived assets that give rise to
23 the obligation. (Title 18 CFR, Part 101)

24 Currently, PSE’s depreciation rates collect the cost of removal, net of salvage, for
25 all four Colstrip units as estimated in a 2006 depreciation study reviewed by the

1 Commission in PSE's 2007 general rate case. That study calculated proposed
2 depreciation rates and annual depreciation expenses including an estimated cost of
3 removal of \$20.4 million for Colstrip Units 1 and 2. This estimate included both
4 unspecified cost of removal, net of salvage, and known AROs at the expected
5 time of plant retirement.

6 While PSE's 2006 depreciation study assumed a probable retirement year of 2019
7 for Colstrip Units 1 and 2, it did not establish a date certain for plant retirement.

8 Through a partial settlement, the parties to PSE's 2007 general rate case agreed to
9 use a longer asset life for the units, as proposed by Commission Staff and the
10 Attorney General's Office of Public Counsel, extending the depreciable life of
11 Units 1 and 2 to 2035 and thus mitigating the impact of the overall rate increase.

12 The Commission approved the partial settlement, including lower depreciation
13 rates for these accounts, effective November 1, 2008.

14 PSE's current rates are authorized to recover the cost of removal and AROs
15 identified in its 2006 depreciation study. However, PSE recorded new AROs of
16 \$16.6 million in June 2015, which exceeds the amounts collected through current
17 depreciation rates. This newly recognized legal obligation for remediation
18 represented the net present value of the estimated future cost of compliance with
19 the final Coal Combustion Residuals ("CCR") rule. Concurrently, PSE began
20 recognizing associated incremental annual depreciation expense of \$1.2 million
21 per year through 2040 for asset retirement costs associated with this ARO.

1 **Q. Are there alternatives to recovering the anticipated decommissioning and**
2 **remediation costs associated with the Colstrip Units 1 and 2 other than**
3 **including these costs in the depreciation rates?**

4 A. Yes. During the 2016 legislative session, Washington's legislature passed Senate
5 Bill 6248, which allows for the Commission to authorize an electric company to
6 place amounts from one or more regulatory liabilities into a retirement account
7 established pursuant to RCW 80.04.350 to cover decommissioning and
8 remediation costs of eligible coal units.

9 **Q. Do the Colstrip Units 1 and 2 qualify as eligible coal units under the new**
10 **law?**

11 A. Yes. In order to qualify, the units must a) have been in service prior to January 1,
12 1980; 2) be owned by more than one electrical company; and 3) provide
13 electricity paid for in rates of Washington customers.¹¹ Colstrip Units 1 and 2
14 meet all three criteria.

15 **Q. Does PSE have regulatory liabilities that could be used to fund the**
16 **decommissioning and remediation costs associated with Colstrip Units 1 and**
17 **2?**

18 A. Yes, as discussed in the Prefiled Direct Testimony of Daniel A. Doyle, PSE
19 currently has regulatory liabilities associated with: (i) Treasury Grants related to
20 upgrades to hydroelectric facilities, which produced incremental hydroelectric
21 generation; and (ii) PTCs, which represent future reductions to PSE's tax liability.

¹¹ See RCW 80.84.010.

1 Both of these regulatory liabilities may be used to fund the decommissioning and
2 remediation costs associated with the retirement of Colstrip Units 1 and 2 if
3 authorized by the Commission.

4 **Q. How does the new law impact PSE's requested depreciation rates in this**
5 **proceeding?**

6 A. The depreciation study presented by Mr. John Spanos in Exhibit No. ___(JJS-3)
7 includes estimated negative salvage values for all four Colstrip units that are
8 designed to cover both the interim salvage along with estimated remediation and
9 decommissioning costs. However, as a result of the new law, PSE is proposing to
10 discontinue the amortization associated with the Treasury Grants that PSE
11 received for the upgrades to its hydroelectric facilities and transfer the remaining
12 regulatory liability to a FERC 108 retirement account that would be established to
13 fund the decommissioning and remediation costs associated with Colstrip Units 1
14 and 2.

15 **Q. Did you modify Mr. Spanos' depreciation study results in your exhibits?**

16 A. Yes.

17 **Q. Please explain the modifications you made to Mr. Spanos' depreciation**
18 **study.**

19 A. In order to recognize the other funding mechanisms available to address Colstrip
20 Units 1 and 2 decommissioning and remediation costs, I have adjusted the
21 depreciation study results used in adjustment 6.06E, and set the net salvage value
22 for Colstrip Units 1 and 2 to zero. By doing so, PSE's proposed depreciation rates

1 are less than they would otherwise be, which reduced the adjustment by
2 approximately \$6.1 million. A corresponding adjustment to record the transfer of
3 the Treasury Grant to the retirement account and discontinue the related
4 amortization expense is discussed further in Adjustment 7.12.

5 My approach is less precise than the approach Mr. Spanos used since it ignores
6 the interim net salvage that will likely occur up to the closure of Colstrip Units 1
7 and 2 in July 2022. However, by setting the net salvage value to zero, I have
8 produced more conservative depreciation rates and this approach is more simple
9 to follow.

10 **Q. How are the Treasury Grants different than the Production Tax Credits in**
11 **terms of the regulatory liabilities created?**

12 A. The primary difference is the Treasury Grants represent actual funds that PSE
13 received and is in the process of returning to customers over the remaining life of
14 the FERC hydroelectric license, whereas the PTCs represent a future, potential
15 benefit and do not have any cash value at this time. As discussed by Mr. Doyle,
16 the PTCs are not funded until they are used as a credit (reduction) on PSE's
17 income tax return. Therefore, PSE does not realize a benefit from the PTCs until
18 PSE has positive net income on its tax return.

19 **Q. Please continue with your explanation of the adjustments.**

20 A. As a result of the restating adjustments discussed above and in the Prefiled Direct
21 Testimony of John J. Spanos, Exhibit No. ____ (JJS-1T), which impact depreciation
22 expense, accumulated depreciation, deferred taxes and federal income tax

1 expense, net operating income is decreased by \$34,610,611 for electric operations
2 and increased by \$13,174,098 for natural gas operations. Rate base is decreased
3 by \$17,305,306 for electric operations and increased by \$6,587,049 for natural
4 gas operations.

5 **Adjustment No. 6.07E Injuries and Damages**

6 This restating adjustment is prepared in accordance with the 2009 general rate
7 case order in Dockets UE-090704 and UG-090705, which restates injuries and
8 damages by adjusting actual test year accruals and payments of injuries and
9 damages to the three-year average of the most recent accruals and payments.

10 Please refer to the Prefiled Direct Testimony of Susan E. Free, Exhibit
11 No. ___(SEF-1T) for a detailed discussion of this adjustment. This adjustment
12 increases net operating income for electric operations by \$69,387.

13 **Adjustment Nos. 6.08 E&G Bad Debt**

14 Consistent with prior cases, this restating adjustment calculates the appropriate
15 bad debt rate by using the average bad debt percentage for three of the last five
16 years after removing the high and low years, which apply to electric and natural
17 gas operations. Since it takes four months to write-off a bill, the ratio of the write-
18 off versus revenue is offset four months. For example, a write-off booked in
19 September 2016 is actually related to revenue that was recognized during the
20 twelve months ending May 2016. Using this relationship between May revenues
21 and September write-offs results in the calculation of an appropriate percentage of
22 write-offs associated with revenues in the test year. The bad debt percentage for a

1 given year is calculated by taking the actual write-offs for the test year and
2 dividing them by the net revenues for twelve months ending in May for each of
3 the years. The net test year revenues as adjusted are multiplied by the calculated
4 average bad debt percentage to determine the amount of restated bad debt
5 expense. This normalized amount is compared to the actual test year level of bad
6 debt expense to determine the effect on income. This bad debt percentage is also
7 used in the conversion factor when determining the final revenue requirement.

8 The impact of this adjustment on net operating income is an increase for electric
9 operations of \$549,350 and a decrease for gas operations of \$158,835.

10 **Adjustment No. 6.09 E Incentive Pay**

11 This restating adjustment uses a four-year average of incentive compensation paid
12 to employees, which is allocated between electric and natural gas operations.

13 Please refer to the Prefiled Direct Testimony of Susan E. Free, Exhibit
14 No. ___(SEF-1T) for a detailed discussion of this adjustment. This adjustment
15 increases net operating income for electric operations by \$157,551.

16 **Adjustment No. 6.10 E Directors and Officers (“D&O”) Insurance**

17 This restating adjustment removes the portion of D&O insurance that should be
18 allocated to non-utility activity. This adjustment also annualizes the most current
19 premiums, which became effective during the test year for the Directors and
20 Officers insurance. Please refer to the Prefiled Direct Testimony of Susan E. Free,
21 Exhibit No. ___(SEF-1T) for a detailed discussion of this adjustment. This
22 adjustment increases net operating income for electric operations by \$16,141.

1 **Adjustment No. 6.11 E Interest on Customer Deposits**

2 This restating adjustment reflects the impact of interest associated with using
3 customer deposits as a reduction to rate base. Please refer to the Prefiled Direct
4 Testimony of Susan E. Free, Exhibit No. ____ (SEF-1T) for a detailed discussion of
5 this adjustment. This restating adjustment, shown on Exhibit No. ____ (KJB-6),
6 page 6.11, decreases net operating income for electric operations by \$108,171.

7 **Adjustment No. 6.12 E&G Rate Case Expenses**

8 Consistent with prior rate cases, PSE has used the history of expense levels for
9 power cost only rate cases (“PCORC”) and general rate cases to determine a
10 normalized level of expenditures by averaging the costs associated with the last
11 two general rate cases as one calculation and the last two power cost only rate
12 cases as another calculation. The average cost for a general rate case using this
13 methodology is \$2.080 million. This cost is allocated 50 percent to electric and 50
14 percent to natural gas, which results in a \$ 1.040 average cost for each energy
15 group. The average cost for a power cost only rate case is \$273,000.

16 The average costs for a general rate case are normalized for recovery over two
17 years and the average costs of a power cost only rate case are normalized over
18 four years. These normalized amounts are then compared to the amount PSE had
19 actually recorded in the test year for each type of rate case expense.

20 This adjustment decreases net operating income for electric operations by
21 \$264,905 and decreases net operating income for natural gas operations by
22 \$280,617.

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Adjustment No. 6.13 E Deferred Gains/Losses on Property Sales

The purpose of this restating and pro forma adjustment is to provide customers with the gains and losses from sales of utility real property completed since the last general rate case. Please refer to the Prefiled Direct Testimony of Susan E. Free, Exhibit No. ___(SEF-1T), for a more detailed discussion of this adjustment.

This adjustment increases net operating income for electric operations by \$171,200.

Adjustment No. 6.14 E Property and Liability Insurance

This pro forma adjustment reflects the actual premium increases for property and liability insurance expense based on premiums currently in place. Updates will be made to policies that will have new premiums during the course of the proceeding. Please refer to the Prefiled Direct Testimony of Susan E. Free, Exhibit No. ___(SEF-1T), for a more detailed discussion of this adjustment. This adjustment increases net operating income for electric operations by \$66,147.

Adjustment No. 6.15 E Pension Plan

This restating adjustment calculates pension expense based on a four-year average of cash contributions to PSE’s qualified retirement fund. Please refer to the Prefiled Direct Testimony of Susan E. Free, Exhibit No. ___(SEF-1T) for a more detailed discussion of this adjustment. This adjustment decreases net operating income for electric operations by \$1,184,945.

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Adjustment No. 6.16 E Wage Increase

This pro forma adjustment reflects the impact of wage increases and payroll tax changes, as described in the Prefiled Direct Testimony of Thomas M. Hunt, Exhibit No. ___(TMH-1T). For a more detailed discussion of this adjustment, please refer to the Prefiled Direct Testimony of Susan E. Free, Exhibit No. ___(SEF-1T). This adjustment decreases net operating income for electric operations by \$1,497,038.

Adjustment No. 6.17 E Investment Plan

This pro forma adjustment adjusts PSE’s portion of investment plan expense to reflect the additional expense associated with the wage increases and is based on the current employee contribution rates. For a more detailed discussion of this adjustment, please refer to the Prefiled Direct Testimony of Susan E. Free, Exhibit No. ___(SEF-1T). This adjustment decreases net operating income for electric operations by \$106,542.

Adjustment Nos. 6.18 E Employee Insurance

Please see the Prefiled Direct Testimony of Thomas M. Hunt, Exhibit No. ___(TMH-1T) for a detailed description of PSE’s employee benefits. This pro forma adjustment adjusts the test year employee benefits expense to the expected most current average cost per participant. For a more detailed discussion of this adjustment, please refer to the Prefiled Direct Testimony of Susan E. Free, Exhibit No. ___(SEF-1T). This adjustment decreases net operating income for electric operation by \$121,751.

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Adjustment Nos. 6.19 E Environmental Remediation

PSE has had deferred accounting for its environmental remediation costs and recoveries since the early 1990s and is requesting recovery of certain of its net deferred environmental costs. Please refer to the Prefiled Direct Testimony of Susan E. Free, Exhibit No. ____ (SEF-1T), for a more detailed discussion of this adjustment. This adjustment decreases net operating income for electric operations by \$924,675.

Adjustment No. 6.20 E&G Payment Processing Costs

This adjustment incorporates Order 01 that the Commission approved in Dockets UE-160203 and UG-160204. The order allowed PSE to pay for and defer the costs for customers' use of debit and credit cards to pay their bills. PSE is allowed to defer the costs that PSE incurred until the beginning of the rate year in the next GRC. PSE is also allowed to recover the fees incurred during the rate year of the next GRC. This adjustment also incorporates a change to payment processing costs as a result of a new service agreement effective October 31, 2016 with PSE's third party payment processor, Fiserv, which will reduce costs overall for non-credit and debit card processing.

There are three purposes for this adjustment. The first is to incorporate the amortization of the deferral of the costs prior to the rate year. The balance of the deferral is based on actual known costs incurred for debit and credit card fees from August 31, 2016 through September 2016 and estimated costs from October 2016 thru December 2017. The estimated costs are based on the actual average

1 cost per transaction as of September 2016 applied to the estimated number of
2 transactions during the deferral period. The estimated number of transactions
3 during the deferral period is determined using the forecast assumptions from the
4 accounting docket. The deferral is being requested for recovery over one year.
5 The costs included in the deferral will be trued up during the course of the
6 proceeding as actuals become known.

7 Second, PSE included an estimate of the costs PSE will incur during the rate year
8 from January 2018 through December 2018. The estimated costs are based on the
9 actual average cost per transaction as of September 2016 applied to the estimated
10 number of transactions during the rate year. The estimated number of transactions
11 during the rate year is determined using the forecast assumptions from the
12 accounting petition docket. The cost per transaction and the estimated rate year
13 transactions will be updated during the course of this proceeding as more updated
14 information becomes known.

15 Third, this adjustment also incorporates the effect of the new service agreement
16 PSE negotiated with Fiserv, which will reduce overall costs for processing non
17 credit and debit card payments.

18 This pro forma adjustment decreases net operating income for electric operations
19 by \$3,087,501 and for natural gas operations by \$2,225,700.

20 **Adjustment No. 6.21 E South King Service Center**

21 This pro forma adjustment captures the net costs associated with PSE's purchase
22 of the South King Service Center. That transaction closed in August 2016. Please

1 refer to the Prefiled Direct Testimony of Susan E. Free, Exhibit No. ___(SEF-1T)
2 for a more detailed discussion of this adjustment. This adjustment increases net
3 operating income by \$434,046 and increases rate base by \$15,915,060 for electric
4 operations.

5 **Adjustment Nos. 6.22 E Excise Tax and Filing Fee**

6 This restating adjustment adjusts the test year to actual expense for the
7 Washington State excise tax and WUTC filing fee that should be recorded for
8 these costs. Please refer to the Prefiled Direct Testimony of Susan E. Free, Exhibit
9 No. ___(SEF-1T) for a more detailed discussion of this adjustment. This
10 adjustment increases net operating income for electric operations by \$10,262.

11 **B. Exhibit No. (KJB-07) Electric Only Adjustments**

12 **Q. Please explain the electric only adjustments.**

13 A. An explanation of the electric only adjustments is as follows:

14 **Adjustment No. 7.01 Power Costs**

15 This schedule, shown on Exhibit No. ___(KJB-7), page 7.01, lines two through
16 eight, adjusts the test year to reflect the power costs that are projected to be
17 incurred during the rate year. The calculation of rate year projected power cost is
18 explained in the Prefiled Direct Testimony of Paul Wetherbee, Exhibit
19 No. ___(PKW-1CT). The change in power costs between the 2016 Power Cost
20 Update effective December 1, 2016, and the current proceeding are shown in
21 Exhibit No. ___(PKW-3) and in more detail in Exhibit No. ___(PKW-4C).

1 Line 10 represents the production operations and maintenance costs (“production
2 O&M”) presented in the Twenty-Fourth Exhibit to the Prefiled Direct Testimony
3 of Ronald J. Roberts, Exhibit No. ___(RJR-25).

4 Line 11 presents the transmission expenses that are related to the Third AC,
5 Northern Intertie and Colstrip transmission lines. This category of costs is left at
6 its historical test year level and the adjustment reflects the result of applying the
7 production factor to these test year expenses.

8 Line 12 depicts revenues associated with variable transmission earned under
9 PSE’s Open Access Transmission Tariff (“OATT”). Consistent with the 2014
10 PCORC, the variable transmission revenues included in this adjustment are
11 calculated by re-pricing the most recent three-year average of transmission
12 volume across the respective lines at the most current OATT tariff rate. New
13 OATT rates under the formula rate will be finalized by June 1, 2017 and their
14 impact on this adjustment will be included during the course of this proceeding.

15 Finally, line 13 allows for the recovery of the equity return of \$1.49 per megawatt
16 hour on deliveries of power under the Coal Transition PPA between PSE and
17 TransAlta Centralia Generation LLC. These changes to total power costs in
18 adjustment 7.01 decrease net operating income by \$19,501,105.

19 **Q. Do you have any further explanations with respect to the power costs in**
20 **Adjustment 7.01?**

21 A. Yes. As power costs and operation and maintenance (“O&M”) costs are also
22 included in other adjustments, it is necessary to reduce the total power cost

1 adjustment by these amounts to avoid a double count in the revenue requirement.
2 Page 2 of Adjustment 7.01¹², depicts these adjustments and presents a
3 reconciliation of the rate year projections included in the testimonies of Mr.
4 Wetherbee and Mr. Roberts, to the final adjusted rate year power cost and O&M
5 projections included in Adjustment 7.01. Specifically, test year benefits and taxes
6 are re-classified out of Mr. Wetherbee's power cost and Mr. Roberts' production
7 O&M totals and reflected separately on lines 15a and 15d on page 1 of the
8 PCA/Fixed Production baseline rate shown in Exhibit No. ___(KJB-8). The rate
9 year power costs excluding the benefits and taxes have been adjusted to test year
10 power cost levels by the appropriate production factor discussed later in my
11 testimony and are the amounts reflected in Adjustment 7.01.

12 **Q. Will you update the PCA Mechanism's baseline rate in this proceeding?**

13 A. Yes. The schedule, shown in Exhibit No. ___(KJB-8), and discussed later in my
14 testimony, adjusts the PCA power cost baseline rate based on the pro forma and
15 restating adjustments made to power costs. The methodology used to calculate the
16 power cost baseline rate is based on the methodology agreed upon in the
17 multiparty PCA Collaborative settlement stipulation that was approved in Order
18 11 in Docket UE-130617, and is discussed in further detail later in my testimony.

¹² Page 2 of 15 of Exhibit No. ___(KJB-7).

1 **Q. Please continue with your discussion of the adjustments.**

2 A. The following are additional electric only adjustments.

3 **Adjustment No. 7.02 Montana Electric Tax**

4 This restating adjustment adjusts the test year amount of Wholesale Energy
5 Transaction Tax (“WET”) and Electricity and Electrical Energy License Tax
6 (“EEL”) to the amount that is projected to be incurred during the rate year based
7 on the power generated at Colstrip based on the current tax structure. The fuel and
8 operating and maintenance costs associated with this generation are reflected in
9 the power cost adjustment. Additionally, the Montana Legislature has proposed
10 legislation that could increase the current WET from .015% to .030% effective
11 July 1, 2017. PSE will update these costs over the course of this proceeding based
12 on the outcome of this legislation. This adjustment increases net operating income
13 for electric operations by \$45,318.

14 **Adjustment No. 7.03 Wild Horse Solar**

15 This adjustment is a restating adjustment which removes the effects of the solar
16 project at PSE’s Wild Horse wind facility. This power project is a demonstration
17 project and PSE is not requesting recovery of the costs associated with it at this
18 time. This restating adjustment is shown in Exhibit No. ___(KJB-7) page 7.03 and
19 increases net operating income for electric operations by \$137,890 and decreases
20 rate base by \$1,969,341.

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Adjustment No. 7.04 ASC 815

This restating adjustment removes the effect of ASC 815 (previously SFAS 133), which represents mark-to-market gains or losses recognized for derivative transactions. This accounting pronouncement is not considered for rate making purposes. This adjustment decreases net operating income for electric operations by \$41,672,584.

Adjustment No. 7.05 Storm Damage

This restating and pro forma adjustment reflects adjustment of the test year expense level of storm damage expense, \$11.1 million, to the normal level of storm damage expense, which is based on the average of the most recent six years. The second part of the storm damage adjustment amortizes the costs related to catastrophic storms that have been deferred. The new deferred costs being requested span a period of more than four years and include storms that have not been approved for recovery in a prior rate case. The deferred costs are shown on lines 23 through 26 and total \$50.7 million. The four-year catastrophic storm deferral balances that were approved for recovery in the 2011 general rate case finished amortizing before the end of the test year, and this account will have a credit balance of \$12.6 million at the start of the rate year. This credit balance represents the amount of storm amortization already recovered that is being used to lower the new deferrals requested for recovery in this proceeding. This brings the total four-year storm cost deferral to \$38.1 million.

1 At the time of preparing this filing in 2016, PSE had experienced four storm
2 events which qualified for deferral and had exceeded the \$8 million threshold
3 required for deferral of qualifying costs. Three of the events occurred in March
4 2016 and so virtually all of their qualifying costs are now known and deferred.
5 The fourth event was a wind storm which occurred on October 14, 2016.
6 Qualifying costs of \$8.3 million (which are included on line 26 of the adjustment)
7 have been deferred for that storm as of October 31, 2016. PSE's storm mechanism
8 requires a report of costs ninety days after a qualifying storm event occurs and at
9 that time, virtually all of the total qualifying costs of the event will be known.
10 Accordingly, the total deferred cost of the October 14th event has not yet been
11 determined and will be updated to actuals during the course of this proceeding.
12 Likewise, this adjustment will be updated during the course of this proceeding to
13 add additional qualifying storm events should they occur.

14 The deferred costs associated with the remaining portion of the December 13,
15 2006 wind storm deferral shown on line 34 will have a balance of \$6.6 million at
16 the start of the rate year. This storm was set to fully amortize over 10 months into
17 the rate year, which is the remaining portion of the 10-year amortization period
18 that was approved in PSE's 2007 general rate case. Therefore, \$6.6 million of
19 amortization expense is being requested for this balance in this proceeding.

20 In January 2012, PSE's service territory experienced a snow and ice event on
21 January 18th swiftly followed by a wind event on January 24th. These two events
22 were commonly referred to as "Snowmageddon" and resulted in a very large
23 deferral balance of \$60.3 million for 2012. (This is shown on line 39 of the

1 adjustment.) Due to the relative size of the balance, PSE proposes that this
2 amount be amortized over six years instead of four years in order to mitigate rate
3 impact on customers. The overall effect of this adjustment is to decrease net
4 operating income for electric operations by \$6,712,556.

5 **Adjustment No. 7.06 Regulatory Assets and Liabilities**

6 This pro forma adjustment adjusts all production related regulatory assets and
7 liabilities that were previously recovered through the PCA Mechanism to their
8 rate year amounts. As I will be addressing in more detail in my discussion of
9 revisions to the PCA mechanism and Exhibit No. ____ (KJB-8) PCA baseline rate,
10 the amortization of power costs related to regulatory assets and liabilities will
11 continue to be considered variable costs and will stay in the rate year power costs
12 included in Adjustment 9.01 instead of being reclassified and treated in the
13 Regulatory Assets and Liabilities adjustment as they have been in past
14 proceedings. The remaining amortization for regulatory assets and liabilities not
15 related to power costs will be considered fixed costs and tracked in the decoupling
16 mechanism. As a result, although the rate base section of this adjustment reflects
17 the average of monthly averages of the rate year for both power cost *and* non-
18 power cost regulatory assets and liabilities, only the *non power cost* regulatory
19 asset and liability amortization for the rate year is reflected in this adjustment.

20 In the 2014 PCORC, the Commission approved three new regulatory assets and
21 liabilities including the RCW 80.80.060-like deferrals associated with the Baker
22 River and Snoqualmie Falls Treasury Grant and the unrecovered cost from the

1 sale of Electron. The Treasury Grant balances were known at the time of the 2014
2 PCORC and no true-ups are needed for these deferrals. In the case of Electron, a
3 true up has been included for the difference between actual deferred costs and
4 those estimated during the 2014 PCORC. The overall impact of this adjustment is
5 an increase to electric net operating income of \$1,736,212 and a decrease to rate
6 base of \$44,085,326.

7 **Adjustment No. 7.07 Glacier Battery Storage**

8 This project is a 2.0 MW/4.4 MWh lithium-iron phosphate battery storage system
9 located on land owned by PSE adjacent to the Glacier Substation. The total
10 project cost of \$11.8 million was partially offset by a Clean Energy Fund Grant of
11 \$3.8 million. The project went into service in May 2016 with additional closings
12 through November 2016. The expected life of the project is 20 years based on and
13 supported by the depreciation study. Please refer to the Prefiled Direct Testimony
14 of Michael Mullally, Exhibit No. ____ (MM-1T) for additional information about
15 this project. The gross plant balance of the project was calculated on an AMA
16 basis for the rate year and when compared to the test year AMA results in an
17 increase to rate base of \$5,283,143 as shown on line 2.

18 Line 10 of the adjustment represents the adjustment to bring depreciation expense
19 to an annual amount based on the proposed depreciation rate of 4.99% for FERC
20 348 Energy Storage Equipment –Production and a weighted average of 3.34% for
21 the other FERC accounts associated with this project in the depreciation study.

22 This amount is shown on line 10 and totals \$216,197. In order to prevent double

1 counting of the portion of the depreciation study adjustment No. 6.06E that
2 adjusts the test year depreciation expense for the Glacier Battery Storage Project,
3 line 11 shows the amount included in the depreciation study adjustment in order
4 to recognize that depreciation expense has already been partially adjusted. The
5 total of lines 10 and 11 is \$223,831.

6 The accumulated depreciation on the building purchase was calculated on an
7 AMA basis for the rate year and is shown on line 3 as \$(722,123). The effect from
8 the depreciation study for accumulated depreciation is shown on line 4 as
9 (\$1,602).

10 The tax treatment for the Glacier Battery Storage Project follows the FERC,
11 which is primarily to “Production”. For tax purposes, the Glacier Battery Project
12 uses a five-year straight line MACRS plus 50% bonus depreciation. The
13 calculation of the deferred taxes is shown on line 5 for this project and is
14 \$(1,717,191). The change in deferred income taxes because of the new
15 depreciation study is shown on Line 6 as \$561.

16 This pro forma adjustment shown on Exhibit No. ___(KJB-7) page 7.07,
17 decreases net operating income for electric operations by \$145,490 and increases
18 rate base by \$2,842,787.

19 **Adjustment No. 7.08 Energy Imbalance Market**

20 This pro forma adjustment presents the rate base items associated with PSE’s
21 participation in the Energy Imbalance Market (“EIM”). As discussed in the
22 Prefiled Direct Testimony of David E. Mills, Exhibit No. ___(DEM-1T), in

1 March 2015 PSE announced its plans to join the EIM operated by the California
2 Independent System Operator (“CAISO”). On October 1, 2016, PSE began
3 participating in the EIM. As stated in the Prefiled Direct Testimony of Paul K.
4 Wetherbee, Exhibit No. ____ (PKW-1CT), although the capital and operating costs
5 of EIM participation are known and measurable, the amount of these benefits that
6 will eventually be realized from EIM participation are not yet measurable and so
7 under traditional ratemaking, the rate year level of EIM benefits would not be
8 appropriately included in rates at this time. However, because the EIM benefits
9 are part of total allowable variable power costs, they are currently being included
10 in the PCA mechanism and therefore, customers are receiving benefits in the PCA
11 mechanism. In contrast, the capital and operating costs that were incurred in order
12 to obtain the benefits of EIM participation are not currently being recovered or
13 included in the PCA mechanism because they are fixed costs in the PCA
14 mechanism.¹³ To alleviate this misalignment between the costs and benefits of
15 PSE’s participation in the EIM, PSE is proposing to pro form in the capital costs
16 of the EIM program in this adjustment. Additionally, Mr. Wetherbee proposes to
17 pro form in the incremental operating costs associated with the PSE employees
18 that were added to oversee PSE’s participation in the market as well as software
19 maintenance fees.¹⁴ Even though the rate year level of EIM benefits are not
20 known and measurable, in recognition of including EIM fixed cost recovery in
21 this proceeding, PSE is proposing to include a reduction in rate year power costs

¹³ Nor are these costs included in the PCA fixed cost deferral approved in Docket UE-161112.

¹⁴ To be included in FERC 557 which is a fixed production cost.

1 that will equally offset the revenue requirement associated with the fixed EIM
2 costs included in this filing. Making such an adjustment will provide alignment of
3 the costs that PSE includes in its decoupling mechanism (where the fixed costs
4 will reside) and its PCA mechanism (where the variable benefits will reside).

5 **Q. Please explain how the rate base was calculated for this adjustment.**

6 A. The total amount of capital associated with PSE's participation in the EIM
7 consists primarily of telemetry, dispatch and communication software that closed
8 to plant in October 2016 and totaled \$16,120,232. This amount was used to
9 determine the AMA plant balance in the rate year. PSE will be updating the total
10 capital costs for the minor capital additions which will occur after October during
11 the course of this proceeding. To calculate the depreciation expense, a
12 depreciation rate of 33.33 percent was applied to the project costs using the three
13 year life that will be designated to this project. The accumulated depreciation
14 AMA balance of \$9,403,469 is shown on line four of this adjustment.

15 Deferred taxes associated with the tax depreciation of the plant were calculated in
16 the manner prescribed by Internal Revenue Code Regulations, Section 1.167(1)-
17 1(h). For the EIM, the deferred tax calculation is based on three-year tax
18 depreciation with an additional half-year bonus depreciation included in tax
19 depreciation for the first year it is in service. The deferred income tax liability
20 balance of \$1,584,894 is shown on line five of this adjustment. The total of all the
21 adjustments described above increases rate base by \$5,131,869.

1 **Q. Please describe the expense adjustment.**

2 A. The calculation of total book depreciation of \$5,373,411 shown on line nine is
3 explained above. The rate year fixed production costs associated with the
4 additional EIM employees and software fees are included in Power Costs
5 Adjustment 7.01 in FERC 557 and are supported by the Prefiled Direct Testimony
6 of Paul K. Wetherbee, Exhibit No. ___(PKW-1CT). As discussed above, the
7 increase to other power costs, FERC 557, in addition to the depreciation expense
8 and return on rate base included in this adjustment, are offset entirely by a
9 reduction to power costs in FERC 555 in the “Costs not in AURORA” section of
10 the power costs support and referred to as the “EIM Benefit.” Because the actual
11 benefits are not known and measurable at this time, the benefits for the EIM
12 Project are assumed to be equal to the total costs for this proceeding. This
13 adjustment decreases net operating income for electric operations by \$3,492,717.

14 **Q. Please continue with your discussion of the adjustments.**

15 A. The following is an electric only adjustment.

16 **Adjustment No. 7.09 Goldendale Capacity Upgrade**

17 This pro forma adjustment presents the rate base items associated with the
18 Goldendale Capacity Upgrade. In January 2016, PSE made a milestone payment
19 for components used in the 2016 major inspection as required under its new
20 contractual service agreement (“CSA”). Improvements in performance associated
21 with installation of the optimization packages and benefits of those improvements
22 are discussed in the Prefiled Direct Testimony of Ronald J. Roberts, Exhibit

1 No. ___(RJR-1CT). The net benefit of reduced power costs in the rate year is
2 included in the power costs adjustment.

3 **Q. Please explain how the adjustment was calculated.**

4 A. In August 2016, PSE retired the old assets and replaced it with the new
5 equipment. The adjustment deals with the removal of the old asset and a pro
6 forma adjustment of the new addition to the rate year in two sections. The first
7 component of the adjustment removes from the test year the AMA of the old plant
8 balance as of September 30, 2016. The second component of the adjustment pro
9 forms the AMA of the new plant to the rate year. The under-depreciated balance
10 of the old plant is also pro formed to the end of the rate year. The new addition is
11 treated in a similar manner in the second component of the adjustment. Please
12 refer to Depreciation Study Adjustment for the explanation of accumulated
13 depreciation portion included in the depreciation study.

14 Deferred taxes associated with the tax depreciation of the plant were calculated in
15 the manner prescribed by Internal Revenue Code Regulations, Section 1.167(1)-
16 1(h). For the Goldendale Capacity Upgrade, the deferred tax calculation is based
17 on twenty-year tax depreciation with an additional half-year bonus depreciation
18 included in tax depreciation for the first year it is in service.

19 The total of all the adjustments described above increases electric rate base by
20 \$18,140,954. This adjustment increases net operating income for electric
21 operations by \$2,156.

1 **Q. Please continue with your discussion of the adjustments.**

2 A. The following is an electric only adjustment.

3 **Adjustment No. 7.10 Mint Farm Capacity Upgrade**

4 This pro forma adjustment presents the rate base items associated with the Mint
5 Farm capacity upgrade. PSE made a prepaid milestone payment in December
6 2016 for components to be capitalized in a major inspection that is required under
7 its long term service agreement (“LTSA”). As discussed in the Prefiled Direct
8 Testimony of Ronald J. Roberts, Exhibit No. ___(RJR-1CT), in addition to the
9 conventional servicing covered by a major inspection, the upgrade is expected to
10 increase capacity and lower the plant’s heat rate once it is in service, which is
11 expected to be May 1, 2017. The net benefit of reduced power costs in the rate
12 year was included in the AURORA modeling when developing rate year power
13 costs.

14 **Q. Please explain how the rate base was calculated for this adjustment.**

15 A. The total estimated cost of the Mint Farm Capacity Upgrade, which includes the
16 milestone payment plus required LTSA costs and construction overhead costs,
17 was used to determine the AMA plant balance in the rate period, or \$24,765,516
18 as shown on line three of this adjustment. To the extent the actual costs differ
19 from this estimate, the impact to this adjustment will be updated during the course
20 of this proceeding. To calculate the depreciation expense for the purposes of
21 determining the accumulated depreciation balances only, the proposed
22 depreciation rate of 8.96 percent for the Mint Farm “Generators – Combined

1 Cycle” FERC 344.20, as outlined in the depreciation study discussed earlier, was
2 applied to the balances during the rate year. The accumulated depreciation AMA
3 balance of \$1,572,187 is shown on line four of this adjustment.

4 PSE anticipates that at the time of the May 1, 2017 in-service date, equipment
5 currently in service will be retired after being replaced by the new equipment,
6 resulting in a reduction to the depreciation expense amount that will offset the
7 additional depreciation expense created from the 2017 major inspection. For this
8 reason and because retirement amounts are not known at this time, PSE assumed
9 the overall impact to depreciation expense after considering the retired assets, will
10 be minimal and no adjustment to depreciation expense is included in this
11 adjustment. This adjustment will be updated when the depreciation expense
12 impact from the retirements becomes known during the course of this proceeding.

13 Deferred taxes associated with the tax depreciation of the plant were calculated in
14 the manner prescribed by Internal Revenue Code Regulations, Section 1.167(1)-
15 1(h). As with Goldendale, the deferred tax calculation for the Mint Farm Capacity
16 Upgrade is based on twenty-year tax depreciation with additional half-year bonus
17 depreciation included in tax depreciation for the first year it is in service. The
18 deferred income tax liability balance of \$4,188,739 is shown on line five of this
19 adjustment.

20 The total of all the adjustments described above increases rate base by
21 \$19,004,590.

1 **Q. Please continue with your discussion of the adjustments.**

2 A. The following is an electric only adjustment.

3 **Adjustment No. 7.11 White River**

4 **Q. Please summarize the regulatory background associated with the White**
5 **River Regulatory Asset.**

6 A. In November 2003, the National Oceanic and Atmospheric Administration-
7 Fisheries (NOAA-Fisheries) issued an opinion containing mandatory conditions
8 that made the economics of operating the White River Hydroelectric Project
9 infeasible. In December 2003, PSE notified FERC that it intended to reject the
10 1997 license; and on January 15, 2004, PSE ceased hydropower operations at
11 White River. At that time, PSE filed an accounting petition in Docket UE-032043,
12 which was eventually consolidated with PSE's 2004 general rate case in Docket
13 UE-040641. In the Final Order in those dockets, the Commission ordered that
14 PSE could defer the net book value of the existing plant costs ("unrecovered plant
15 costs") in FERC 182.2 "Unrecovered plant and regulatory study costs" as well as
16 defer in FERC 182.3 "Other regulatory assets" the costs net of proceeds
17 associated with the then current efforts to relicense the plant with FERC, to fulfill
18 safety and regulatory requirements as well as to obtain water rights ("relicensing
19 and CWIP costs"). Both deferrals were allowed to be included in production rate
20 base. The unrecovered plant cost deferral was allowed to be amortized at the level
21 of depreciation that existed at the time the plant was decommissioned. The
22 Commission did not allow amortization of the relicensing and CWIP deferral. The

1 Commission also ordered that the net proceeds from the sale of White River
2 assets would be booked against the deferral. Finally, the Commission required
3 PSE to bring the application of proceeds from the sale and disposition of any
4 remaining balances for consideration in a future proceeding.

5 **Q. Please explain the regulatory proceeding in UE-090399.**

6 A. PSE had pursued efforts to recoup its investment in the White River properties
7 and dispose of the assets in a manner consistent with the public interest. PSE
8 entered an agreement with the Cascade Water Alliance (“CWA”) in which CWA
9 would purchase certain project assets and property for \$25 million plus an
10 additional \$5 million once PSE met certain conditions, which it eventually did.
11 CWA would not agree to purchase the remaining surplus properties. Based on
12 these circumstances and the finalization of the CWA deal, in 2009, PSE filed an
13 application in Docket UE-090399 for authorization to transfer the White River
14 assets to the CWA as well as an application for waiver of RCW 80.12.020 and
15 Washington Administrative Code (“WAC”) 480-143-120 associated with the
16 disposition of the surplus properties which at the time, PSE expected to sell in the
17 near future.

18 **Q. What was the outcome of the 2009 proceeding?**

19 A. The Commission authorized PSE to transfer the project assets to CWA but the
20 application for waiver of RCW 80.12.020 and WAC 480-143-120 with regard to
21 the surplus properties was denied. Additionally, all deferred costs associated with
22 maintaining or selling the properties and net proceeds received were to continue

1 to be deferred pursuant to Docket UE-032043, and PSE would be required to
2 bring the issue of the application of proceeds from the sale and disposition of
3 surplus property to the Commission for consideration in PSE's next general rate
4 case after the sale of the surplus properties was completed.

5 **Q. Please summarize your request as it relates to the White River surplus**
6 **properties.**

7 A. As discussed in the Prefiled Direct Testimony of Paul K. Wetherbee Exhibit
8 No. ___(PKW-1CT), PSE categorized the surplus properties into four main
9 categories:

- 10 • Properties that had a chance of being marketed and sold;
- 11 • Properties that PSE should maintain for utility operations or
12 facilities use;
- 13 • Properties that would require significant investment to
14 remediate for environmental reasons if sold; and
- 15 • Properties that can be used in the future as habitat
16 mitigation for other PSE projects such as PSE's current
17 Eastside 230 kV project.

18 A detailed description of PSE's efforts related to each of the above categories and
19 the outcomes relevant to this proceeding are discussed by Mr. Wetherbee.

20 In this proceeding PSE is requesting the following Commission approval based on
21 the category of property which will fully resolve the White River regulatory asset:

- 22 • **Properties That Have Been Sold.** The following properties have been
23 sold and PSE is requesting that their value remain in the regulatory asset
24 net of existing approved amortization and net sales proceeds and that the
25 full balance of the regulatory asset now be allowed for recovery.

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- **Cascade Water Alliance Property and Associated Water Rights:** The net proceeds associated with this transaction have been deferred in the regulatory asset.

- **Surplus Properties That Have Been Sold:** Additionally, of the remaining Surplus Properties, PSE has sold all properties that were viably marketable as are summarized in Exhibit No. ___(PKW-7) and deferred the net proceeds in the regulatory asset as was required.¹⁵

- **Properties That Should Be Retained For System Operations.** PSE is requesting that it be allowed to transfer the properties that it uses for system and facilities operations that are summarized in Exhibit No. ___(PKW-7) from FERC 182.2 “Unrecovered plant and regulatory study costs” into FERC 101 “Electric plant in service.” The Prefiled Direct Testimony of Paul K. Wetherbee Exhibit No. ___(PKW-1CT), describes proceeds and costs that are yet to be received and incurred associated with timber sales on property within this category. PSE will update the adjustment during the course of this proceeding to include the proceeds from the timber contract once known. Additionally, the costs to reforest the property that are discussed in the Prefiled Direct Testimony of Paul K. Wetherbee Exhibit No. ___(PKW-1CT), may be incurred after the end of this proceeding. PSE is not requesting recovery of these costs in this proceeding. Rather, if PSE’s request is granted, the property will be held in Electric plant in service, and these reforestation costs will be recorded in compliance with the FERC Uniform System of Accounts at the time they are incurred.

- **Properties That Should Be Maintained As The Least Cost Option To Environmental Remediation.** PSE is requesting that it be allowed to transfer the properties that it will hold as a lower cost alternative to environmental remediation that are summarized in Exhibit No. ___(PKW-7) from FERC 182.2 “Unrecovered plant and regulatory study costs” into FERC 101 “Electric plant in service.”

- **Properties That PSE Should Hold For Habitat Mitigation.** PSE is requesting that it be allowed to transfer the properties that it will hold for purposes of habitat mitigation on future PSE projects as are summarized in Exhibit No. ___(PKW-7) from FERC 182.2 “Unrecovered plant and regulatory study costs” into FERC 105 “Electric plant held for future use.”

¹⁵ The sales prices of all of the Surplus Properties that have been sold were under the limit that requires specific approval under WAC 480-143-180. When required, PSE did report the sales of these Surplus Properties on its annual reports that have been filed under WAC 480-143-190 and Dockets U-89-2688-T, U-89-2955-T Findings of Fact paragraph 19.

1 **Q. Please summarize your Adjustment No. 7.11E as it relates to the requested**
2 **regulatory treatment in this proceeding.**

3 A. This adjustment transfers the value of the land that PSE is requesting be
4 transferred out of the regulatory asset into FERC accounts 101 and 105.
5 Additionally, it pro forms the regulatory assets—which includes the value of the
6 unrecovered plant net of accumulated amortization and the net proceeds received
7 for all White River land sold—to the beginning of the rate year at its existing
8 authorized level of amortization.

9 PSE is requesting a three year amortization period for the combined balance of
10 the White River regulatory assets beginning January 1, 2018.

11 This adjustment presents, on an AMA basis, the combined White River regulatory
12 assets on lines one through three. The AMA balances of accumulated
13 amortization and deferred income tax liability are presented on lines four and five.

14 This adjustment decreases net operating income by \$3,376,409 and decreases rate
15 base by \$3,888,479.

16 **Q. Please continue with your discussion of the adjustments.**

17 A. The following are electric only adjustments.

18 **Adjustment No. 7.12 Transfer of Hydro Treasury Grants in Rate Base**

19 As I discussed earlier in Depreciation Study Adjustment 6.06, this restating
20 adjustment transfers the net balances of the Hydro Treasury Grants in electric rate

1 base from “Deferred Debits and Credits” to a FERC 108 retirement account for
2 Colstrip Units 1 and 2, and removes the amortization from the test year.

3 The adjustment removes the net AMA balances of the hydro grants in the test year
4 by \$101,559,499 on line two of the adjustment and transfers the rate year balance
5 of \$95,819,884 to the proposed retirement account in line three, for a net increase
6 to rate base of \$5,739,615. The adjustment decreases net operating income by
7 \$2,131,857.

8 **Adjustment No. 7.13 Production Adjustment**

9 This pro forma adjustment decreases production related rate base and certain
10 production expenses by the load and customer production factors that were used
11 for calculating power costs. The adjustment is applied to the production related
12 items to “gross down” expense levels as recovery of these expenses are
13 anticipated to be offset by the expected load or customer growth between the test
14 year and the rate year. A “gross up” would be applied if load or customers were
15 expected to decline between the test year and the rate year. The production factor
16 PSE is proposing in this case differs from previous cases to reflect changes to the
17 PCA mechanism that resulted from a multiparty settlement.

18 Modifications to PSE’s PCA mechanism were agreed to in a multiparty settlement
19 and approved in Order 11 of PSE’s 2013 PCORC in Docket UE-130617. The
20 power cost baseline rate continues to be comprised of both variable and fixed
21 production costs, but beginning January 2017, only the variable production costs
22 will continue to be tracked in the PCA balancing mechanism. Parties to the 2013

1 PCA Settlement agreed that the fixed production and delivery costs be included in
2 the decoupling mechanism, assuming the decoupling mechanism continues
3 pending the outcome of this proceeding.

4 Because the decoupling mechanism tracks costs on a dollar per customer basis, a
5 production factor incorporating the growth or decline of customers, as opposed to
6 the growth or decline of load, is a more appropriate factor to apply to the fixed
7 production and delivery costs expected to be tracked in the decoupling
8 mechanism.

9 As a result, in addition to a variable production factor based on load assumptions,
10 a fixed production factor has been developed for this proceeding, based on
11 customer growth. The variable production factor is based on the ratio of the test
12 period normalized delivered load to the expected rate year delivered load, which
13 is 96.161%. The complement of this amount, or 3.839%, is the variable
14 production factor that is used in the production adjustment itself for variable items
15 tracked in the PCA mechanism. The fixed production factor is based on the ratio
16 of the test period average customer count to the expected rate year average
17 customer count, which is 97.465%. The complement of this amount, or 2.535%, is
18 the fixed production factor that is used in the production adjustment itself for the
19 fixed items tracked in the decoupling mechanism. Only one item in the production
20 adjustment, Montana Energy Tax, uses the variable production factor, while the
21 remaining items are considered fixed production costs and use the fixed
22 production factor.

1 Included in the variable production factor calculation is the MWh increase to test
2 year load for the weather normalization adjustment discussed in Adjustment 6.02.

3 This adjustment increases net operating income for electric operations by
4 \$3,130,918 and decreases rate base by \$54,768,452.

5 VI. POWER COST ADJUSTMENT

6 **Q. Has the methodology used to derive PSE's proposed power cost baseline rate**
7 **changed since the 2014 PCORC?**

8 A. Yes, as discussed above, modifications to PSE's PCA mechanism were approved
9 in Order 11 of PSE's 2013 PCORC in Docket UE-130617, as outlined in the
10 multiparty settlement stipulation ("the PCA Settlement"). The PCA Settlement
11 addressed five broad issues that became effective on January 1, 2017 including:

- 12 • Removal of Fixed Production Costs from the PCA
13 imbalance calculation;
- 14 • Modifications to the dead band and the sharing bands;
- 15 • A change to the refund or surcharge trigger;
- 16 • Timing and stay out provisions; and
- 17 • Treatment of administrative costs of PSE's hedging
18 program.

19 **Q. Would you please describe the removal of fixed production costs?**

20 A. The PCA Settlement proposed to remove the recovery of fixed production costs
21 from the PCA mechanism and collect these costs through the decoupling
22 mechanism if it continues. Up until January 1, 2017, fixed costs were recovered

1 on a dollar per MWh basis through the PCA mechanism, subject to dead bands
2 and sharing bands. Under the proposed methodology, these fixed costs would be
3 recovered on a dollar per customer basis along with other delivery costs currently
4 tracked in the decoupling mechanism. On November 10, 2016, the Commission
5 approved PSE's accounting petition in Docket UE-161112 requesting
6 authorization to defer the fixed production related costs incurred from January 1,
7 2017 through the date rates for this proceeding become effective.

8 The Exhibit A-1 used in the 2016 Schedule No. 95 Power Cost Update filing,
9 Docket UE-161135, is the basis for Exhibit No. ____ (KJB-8), page 1. Exhibit A-1
10 has been updated to reflect production related costs expected in the rate year and
11 in conformance with treatment adopted in the current PCA mechanism. The
12 baseline rate is comprised of the total fixed production costs summed in column
13 IV, plus the variable production costs summed in column V. Beginning January 1,
14 2017, only the variable costs in Column V are tracked in the PCA balancing
15 mechanism while the fixed costs are being deferred and the balance will be
16 included in the annual Schedule 142 rate filing.

17 The fixed costs being requested for tracking in the decoupling mechanism
18 include:

- 19 • Return on fixed production plant and specific transmission
20 assets;
- 21 • Return on production-related regulatory assets and
22 liabilities;
- 23 • Depreciation expense for production plant and certain
24 transmission assets;

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- Production O&M (including payroll overhead taxes);
- Other power supply expenses, FERC account 557 (including payroll overhead taxes);
- Property insurance associated with production plant;
- Amortization of non-power cost regulatory assets and liabilities (any amounts other than those amortized in FERC accounts 501, 547, 555 and 565);
- Transmission expense related to the 500 kV line; and
- Transmission revenue related to Colstrip, Third AC and Northern Intertie.

The variable costs continuing to be tracked in the PCA balancing mechanism include:

- Fuel, FERC accounts 547 and 501;
- Purchase and interchange, FERC account 555;
- Purchases/Sales of non-core gas, FERC account 456.0;
- Hedging gains or losses on fuel and power purchases and sales related brokerage fees;
- Sales to others, FERC account 447;
- Wheeling costs, FERC account 565;
- Amortization of production regulatory assets or liabilities amortized to accounts 501, 547, 555 and 565;
- Account 408.1 – Montana electric energy taxes; and
- Equity adder associated with the coal transition PPA.

As discussed in the Production Adjustment, a different production factor, calculated based on either delivered MWhs or number of customers, would be

1 used to bring rate year power costs back to the test year level, depending on
2 whether they are designated as fixed or variable. The total fixed costs of
3 \$554,392,226 are divided by the test year delivered load of 20,723,206 MWhs to
4 calculate the fixed costs portion of the baseline rate of \$26.752 per MWh before
5 revenue sensitive items and \$28.090 per MWh after revenue sensitive items. The
6 total variable costs of \$712,110,882 are divided by the test year delivered load to
7 calculate the variable costs portion of the baseline rate of \$34.363 per MWh
8 before revenue sensitive items and \$36.081 per MWh after revenue sensitive
9 items. The total proposed baseline rate is \$61.115 per MWh before revenue
10 sensitive items and \$64.171 per MWh after revenue sensitive items.

11 **Q. Would you please describe modifications to the dead band and the sharing**
12 **bands?**

13 A. The PCA Settlement reduced the size of the dead band from \$20 million to \$17
14 million, in order to provide earlier sharing of both costs and benefits. The first
15 sharing band for either costs (under-recovery) or benefits (over-recovery) is \$17
16 million to \$40 million. In the first band, under-recovery is shared equally between
17 customers and PSE, while over-recovery is shared between customers and PSE at
18 65 percent and 35 percent, respectively. For any over or under-recovery in excess
19 of \$40 million, the third band, customers and PSE will share the cost or benefit at
20 90 percent and 10 percent, respectively. There are only three bands in the new
21 mechanism, the dead band and two sharing bands.

1 **Q. Would you please describe changes to the refund or surcharge trigger?**

2 A. When the balance of the PCA deferral account reaches a certain balance amount,
3 the mechanism triggers a refund or surcharge to customers. The PCA Settlement
4 reduced the trigger from \$30 million to \$20 million.

5 **Q. Please explain the timing and stay out provisions agreed to in the PCA**
6 **Settlement.**

7 A. The revised PCA mechanism began January 1, 2017 and will continue unchanged
8 through at least January 1, 2022, consistent with the settling parties' agreement to
9 a five-year moratorium on further modifications to the PCA mechanism.

10 Additionally, the PCA Settlement:

- 11 • removes the requirement that PSE file a GRC within three
12 months of the PCORC rate's effective date; and
- 13 • precludes PSE from filing a GRC or PCORC within six
14 months of any PCORC's rate effective date.

15 These provisions are intended to eliminate the administrative burden of
16 processing the GRC or PCORC shortly after one has just become effective.

17 Outside of the temporary moratorium, PSE's ability to file a PCORC will not
18 change, including the continued use of the PCORC to update variable power costs
19 and fixed production costs.

20 **Q. Would you please describe how the hedging line of credit costs will be**
21 **recovered according to the PCA Settlement?**

22 A. The administrative and line of credit costs of executing a hedging program were
23 originally excluded from the PCA until 2007 when interest costs and commitment

1 fees associated with the electric hedging activities were added to net power costs
2 recovered through the PCA. The Settlement removes these “hedging line of credit
3 costs” from the PCA and stipulates they should be included in PSE’s cost of
4 capital instead. Schedule A-1 of Exhibit No. ___(KJB-8), line 26 depicts the
5 absence of hedging line of credit costs in the current baseline rates. The inclusion
6 of costs for the existing \$350 million facility supporting energy hedging in PSE’s
7 proposed cost of capital are discussed in the Prefiled Direct Testimony of
8 Brandon J. Lohse, Exhibit No. ___(BJL-1T).

9 **Q. Please summarize Schedule A-1 in Exhibit No. ___(KJB-8)**

10 A. Exhibit A-1 is important for two reasons. First, Exhibit A-1 identifies the specific
11 production related costs that are being updated in any given GRC or PCORC, and
12 which make up the baseline rate that is used to calculate changes in revenue
13 deficiency in a PCORC. Second, Exhibit A-1 will also be the source of
14 information used in designating both the variable and the fixed components of the
15 total production baseline rate, the former which will be used in tracking the over
16 or under collection of variable power costs in the PCA mechanism and the latter
17 to be used to track fixed production costs in the decoupling mechanism.

18 Beginning January 1, 2017, Exhibit B, which calculates the PCA imbalance for
19 sharing and is presented in PSE’s annual compliance filings required under the
20 PCA mechanism, will use only the variable power cost baseline rate to calculate
21 an imbalance. This variable baseline rate multiplied by the actual delivered load
22 for a period is the amount of variable power costs that are included in customers’

1 rates. The product of this calculation will be compared against only the actual
2 allowable variable power costs during the reporting period plus any adjustments
3 in Exhibit B, to determine the imbalance for sharing against which the bands are
4 applied to determine the deferral balance at the end of each PCA period.

5 VII. EXPEDITED RATE FILING

6 **Q. How does PSE propose to address the attrition that is likely to occur during**
7 **the pendency of this general rate case?**

8 A. PSE is requesting that the Commission formalize procedures related to filing an
9 expedited rate filing, which would build on the approach approved in Dockets
10 UE-130137 and UG-130138.

11 **Q. Please explain the purpose of an expedited rate filing.**

12 A. The purpose of an ERF is to update the base rates established in PSE's general
13 rate case with known and measurable changes since the test year. In PSE's 2011
14 general rate case, Commission Staff proposed an expedited filing methodology
15 that would allow PSE to update the "relationships between rate base, revenues
16 and expenses"¹⁶ in its rates on an expedited basis in order to address some of the
17 regulatory lag inherent in Washington's historical ratemaking approach. In order
18 to reduce controversy and allow for the case to be reviewed on an expedited basis,
19 Commission Staff proposed that an expedited filing "could not request a change

¹⁶ Dockets UE-111048 and UG-111049, Elgin, Exh. No. KLE-1T at 81:7.

1 in the rate of return, except to update debt costs for known changes”;¹⁷ “there
2 should be no rate spread or rate design changes”;¹⁸ and “the filing would contain
3 “restating adjustments only . . . to ‘clean’ the books in order to reflect proper
4 ratemaking.”¹⁹

5 **Q. Why is PSE requesting a formal process for an expedited rate filing**
6 **methodology be established at this time?**

7 A. When the Commission approved PSE’s expedited rate filing in 2013, the
8 Commission indicated that it was a one-time mechanism. Therefore, even if PSE
9 filed another ERF using the same methodology approved in Dockets UE-130137
10 and UG-130138, there is uncertainty as to whether the Commission would
11 consider the filing on an expedited basis. PSE believes it is important to have
12 some certainty in the regulatory process in order for an ERF mechanism to
13 successfully address the inherent regulatory lag associated with traditional
14 historical ratemaking and to break the cycle of back to back general rate case
15 filings. One of the most critical elements is for ERF rates to be implemented in a
16 condensed time period, such as a 60 to 90 day timeframe. Since an ERF is merely
17 an update of PSE’s costs based on the Commission Basis Report format and
18 specifically is not to include any pro forma adjustments, an extended procedural
19 schedule is not necessary. If the extended procedural schedule is required it

¹⁷ *Id.* at 81:8-9.

¹⁸ *Id.* at 81:12-13.

¹⁹ *Id.* at 81:9-12.

1 removes any advantages associated with such a filing and essentially forces PSE
2 into filing back to back general rate cases.

3 **Q. Has the Commission encouraged utilities to consider expedited rate filings**
4 **along the lines suggested by Commission Staff?**

5 A. Yes. In Order 08 in Dockets UE-111048 and UG-111049, where Staff first
6 proposed an ERF like filing, the Commission stated it “appreciate(s) Staff’s
7 willingness to bring forward the outline of a proposed process mechanism to help
8 address the particular problems associated with PSE’s current position in a cycle
9 of capital investment.”²⁰ The Commission stated that it would give fair
10 consideration to a PSE filing along the lines Staff suggested in that case.

11 Additionally, the Commission stated it “would be particularly interested in
12 proposals that might break the current pattern of almost continuous rate cases.”²¹

13 Following this initial concept, the Commission has also discussed ERFs as an
14 option in several other utilities general rate cases, including most recently in
15 Order 6 in Docket UE-160228, the Avista general rate case.

16 **Q. Was PSE’s filing in UE-130137 and UG-130138 consistent with the approach**
17 **outlined in Commission Staff’s testimony in Dockets UE-111048 and UG-**
18 **111049?**

19 A. Yes. Although Commission Staff’s testimony in the 2011 case did not include
20 many details, the testimony was clear that the proposed expedited filing would

²⁰ Order 08 ¶ 506.

²¹ *Id.* ¶¶ 506-07.

1 1) not include changes in the rate of return, rate spread or rate design, and
2 2) include only restating adjustments that are necessary to reflect proper
3 ratemaking. PSE incorporated both of those principles into its 2013 ERF filing
4 and would continue to do so in any future ERF filings.

5 **Q. Please explain what costs would be included in the ERF filing.**

6 A. Similar to the approach used in the 2013 ERF filing, PSE would prepare a
7 Commission Basis Report for determining the revenue deficiencies consistent
8 with the approach defined in WAC 480-90-257 and WAC 480-100-257. Utilizing
9 this CBR format, costs would then be segregated into two categories: 1) power
10 cost/purchased gas/CRM related, 2) and all other items. Items included in the “all
11 other” category are the costs that will be used to determine the electric and natural
12 gas revenue requirement deficiency associated with the expedited rate filing.

13 **Q. Why does PSE propose to exclude power costs, and purchased gas costs from**
14 **an ERF?**

15 A. The primary reason for excluding power costs, purchased gas costs, and CRM is
16 there are other approved mechanisms in place for addressing changes in those
17 costs. Additionally, in a general rate proceeding, power costs are calculated on a
18 forward-looking, pro forma basis and that methodology would be inconsistent
19 with the historical restating approach embedded in the CBR. Attempting to update
20 power costs would unnecessarily complicate the expedited rate filing and likely
21 make it more contentious.

1 **Q. Is 60 to 90 days a reasonable timeframe to allow Commission Staff and other**
2 **stakeholders an opportunity to review the filing?**

3 A. Yes. Since the filing includes only the standard restating ratemaking adjustments,
4 utilizing existing methodologies previously approved by the Commission, review
5 should be able to be accomplished on an expedited basis.

6 **Q. Would an ERF filing include changes to cost of capital?**

7 A. No. As originally envisioned by Commission Staff, an expedited filing “could not
8 request a change in the rate of return, except to update debt costs for known
9 changes.”²² Such an approach is also consistent with the Commission’s decision
10 in Order 15 in Docket UE-130137 and UG-130139, where the Commission stated
11 there is no “reason for the Commission to undertake this detailed and costly
12 analysis when the issues have been recently decided.”²³ The Commission made a
13 similar decision in Pacific Power’s 2014 general rate case where the Commission
14 relied on RCW 80.04.200 and declined to rehear return on equity or capital
15 structure.²⁴ In that case, the Commission reasoned that there had been no material
16 change in the markets or PSE’s access to them.

17 **Q. Are there advantages to expedited rate filings over an attrition adjustment?**

18 A. Yes. One of the advantages of allowing an ERF versus an attrition adjustment is
19 that an ERF still utilizes the Commission’s preferred historical ratemaking
20 approach, granted on a simplified and expedited basis. This compares to an

²² Dockets UE-111048 and UG-111049, Elgin, Exh. No. KLE-1T at 81:8-9

²³ Dockets UE-130137 and UG-130138 *et al.*, Order 15/14 at 12, ¶ 21, n. 18.

²⁴ *See* Dockets UE-140762 *et al.*, Order 08, 76-77, ¶ 181.

1 attrition adjustment that estimates the attrition that will occur between the test
2 year and the rate year based on historical trends in rate base, revenues and
3 expenses. With an ERF there are no estimates and, as a result, ERF rates will be
4 based on the Commission's long standing preference to utilize actual known and
5 measurable costs.

6 **Q. Does this mean that PSE would not request an attrition adjustment in a**
7 **future general rate case proceeding?**

8 A. No, PSE's request to formalize the timing and process for an expedited rate filing
9 is not intended to limit PSE's ability to request an attrition adjustment or multi-
10 year rate plan, similar to the K-factor approved in the 2013 dockets in a future
11 general rate case proceeding.

12 **VIII. ELECTRIC COST RECOVERY MECHANISM FOR**
13 **TARGETED RELIABILITY PROJECTS**

14 **Q. Why is PSE proposing an Electric Cost Recovery Mechanism?**

15 A. As discussed in the testimonies of Booga Gilbertson and Catherine A. Koch, PSE
16 is requesting an Electric Cost Recovery Mechanism in order to accelerate the
17 replacement of targeted reliability improvements intended to reduce the number
18 and length of outages. The ECRM would allow PSE to recover actual known and
19 measurable costs incurred as a result of the targeted replacement program during
20 the interim periods between rate cases comparable to the methodology currently
21 authorized for the gas pipeline replacement program adopted in the Commission's

1 Accelerated Replacement Policy, Docket UG-120715. (Also referred to as the
2 “Gas CRM “).

3 **Q. What would the Electric Cost Recovery Mechanism include?**

4 A. Consistent with the Gas CRM, PSE proposes that the ECRM allow for recovery
5 of the return on the prior year’s plant investment along with the depreciation
6 expense associated with the program expenditures for targeted reliability
7 investment. Exhibit No. ____ (KJB-9) provides an example of the simple cost-of-
8 service calculation that would be filed annually as part of the proposed ECRM.
9 This format, which is based on the previously approved Gas CRM filings, ensures
10 that the calculations are transparent, easily calculated and can be understood by
11 all parties. The revenue requirement includes only the depreciation expense,
12 return on investment and income taxes associated with the program’s targeted
13 reliability investment during the calendar year. The return on investment
14 calculation is calculated by multiplying PSE’s authorized rate of return to the
15 program year investment, net of accumulated depreciation and deferred taxes. By
16 looking retrospectively at PSE’s targeted reliability replacement program
17 spending, the Commission and interested parties can ensure that the program
18 investments are consistent with the specific replacement plans and are in service
19 prior to their inclusion in rates.

1 **Q. How is the proposed ECRM consistent with the Accelerated Replacement**
2 **Policy adopted by the Commission in Docket UG-120715?**

3 A. The key elements from the Accelerated Replacement Policy and how they are
4 reflected in the ECRM are as follows:

5 Excluded Costs: The Accelerated Replacement Policy required that O&M
6 expenses, including costs associated with locating assets, normal growth, system
7 expansion, or third-party damage, would not be included in the CRM, nor would
8 costs related to replacement of infrastructure required by a previous Commission
9 order or approved settlement be included in the mechanism. For purposes of the
10 ECRM, PSE is proposing to exclude these costs as well.

11 Time Frame: The Accelerated Replacement Policy allows accelerated recovery of
12 program costs for up to four years at which time a general rate case filing is
13 required to fold plant investments into base rates otherwise the CRM would be
14 discontinued. PSE proposes that the ECRM would include the same requirements.

15 Accounting Treatment: The accounting treatment is consistent with normal
16 accounting and does not provide for deferral of cost or accrual of interest on that
17 cost for later recovery. Consistent with the Gas CRM, PSE will utilize normal
18 accounting methods to track the work specific to the reliability plan and will not
19 look to defer costs or accrue interest for later recovery.

20 Recovery and Cost of Service: The cost of service and related recovery would be
21 based on the prior year's plant investment and depreciation expense associated
22 with eligible assets that are part of the plan and have been placed in service and

1 are determined to be used and useful. The rate of return utilized in the ECRM
2 filing will be based on the capital structure and cost of equity approved in PSE's
3 most current general rate case.

4 Tariff Filings and Billing: A tariff filing would occur annually with the initial
5 filing occurring six months prior to the effective date. Similar to the Gas CRM,
6 PSE would file an update 45 days prior to the effective date to reflect actual
7 reliability plan expenditures leaving only the last two months as an estimate. The
8 ECRM would be reflected in tariff schedule 149 which has been filed in this case.

9 Cost Cap: In order to ensure that the plan is a measured and reasonable response
10 to improve reliability beyond historical levels, PSE has proposed an annual cap
11 for program year expenditures of \$110 million per year. This level of annual
12 spending would result in approximately \$16.1 million of incremental revenue
13 requirement per year, or approximately 0.7% annual increase to overall rates.

14 **Q. Are there any specific areas where the proposed ECRM differs from the**
15 **Accelerated Replacement Policy adopted by the Commission in Docket UG-**
16 **120715?**

17 A. Yes, as discussed in the Prefiled Direct Testimony of Jon A. Piliaris, Exhibit
18 No. ___(JAP-1T), PSE is proposing a different methodology for allocation of
19 costs for rate design purposes to ensure that costs follow benefits.

1 **Q. Please describe the proposed filing dates for the Electric Cost Recovery**
2 **Mechanism.**

3 A. PSE proposes that the ECRM program year be based on the calendar year. PSE
4 proposes that costs associated with the Electric Reliability Plan which is included
5 as the Second Exhibit to the Prefiled Direct Testimony of Catherine A. Koch,
6 Exhibit No. ___(CAK-3C), will be included in rates effective January 1st of each
7 year, for the work completed and placed in service during the prior year. Similar
8 to the Gas CRM, PSE envisions that PSE would make two rate filings regarding
9 the program year expenditures in order to provide transparency and adequate time
10 for the parties to review the rate filings that are based on the reliability plan and
11 the associated spending. This initial filing for the program year would occur on
12 July 1st of each year and the filing would include actual and forecasted
13 expenditures for the program year. The initial filing would include actual
14 expenditures for the January through May 31st period, with forecasted
15 expenditures for the June through December period for the program year. PSE
16 would then update the filing by November 30th with actuals through October of
17 the program year, and estimates for the remaining two months of the program
18 year. The estimated months are trued-up in the following year filing. Electric
19 CRM rates would then become effective the following January 1st.

20 PSE is proposing one less rate filing per year than the Gas CRM, and is proposing
21 one more month of estimates than in the Gas CRM. The reason for the additional
22 month of estimates is that, in PSE's experience, it is difficult to file the second
23 Gas CRM update with eleven months of actuals and also provide Commission

1 Staff enough time to finalize their Open Meeting Memos in time for the Open
2 Meeting that occurs prior to the final rate change. Therefore, allowing two months
3 of forecast in the Electric CRM will allow Commission Staff adequate time to
4 review the filing. Additionally, this is consistent with many of PSE's tracker and
5 rider rate filings which utilize two months of estimated information that is trued
6 up in the subsequent year's filing.

7 **Q. Is there a true up in the following year if actual expenditures for the program**
8 **year differ from the estimate included in rates?**

9 A. Yes. Similar to the gas cost recovery mechanism, in the following year's ECRM
10 filing, a true-up adjustment is calculated to address any difference between the
11 estimated spending and the actual expenditures for the prior program year.
12 Additionally, after the initial year, the ECRM will include a separate revenue
13 requirement calculation by program year in order to consider changes to net rate
14 base. As discussed earlier, this process would be continued for up to four years, at
15 which time PSE must file a general rate case to include all plan investment in base
16 rates and reset the tariff to exclude the ECRM recovery.

17 **Q. Please describe how the timing may be different the first year of the plan.**

18 A. As discussed in the Prefiled Direct Testimony of Catherine A. Koch, Exhibit
19 No. ___(CAK-1CT), PSE is filing the 2017 and 2018 Electric Reliability Plan
20 (Exhibit No. ___(CAK-3C)) for inclusion in the Electric Cost Recovery
21 Mechanism should it be approved by the Commission. PSE recognizes that this
22 means the first year of implementing the plan (2017) is concurrent with the

1 proposal of this mechanism and with the general rate case proceedings. As a
2 result, PSE will file its initial filing that includes actuals for January 1 to May 31
3 plus projected costs for June 1 through December 31 at the time of PSE's rebuttal
4 testimony in this case. So as not to create complexity during the conclusion of the
5 rate case proceeding, for this initial year, PSE will not file updated projected costs
6 for 2017 on November 15. Instead PSE will file actuals for January 1st to October
7 30th plus projected costs for November 1st through December 31st at the
8 compliance filing in this proceeding.

9 **Q. Please describe how the revenue requirement would be calculated?**

10 A. The formula for calculating the ECRM revenue requirement is provided in
11 Exhibit No. ___(KJB-9). This methodology is consistent with the methodology
12 recommended in the Accelerated Replacement Policy and has been the basis of
13 the Gas CRM rates approved in Dockets UG-141212, UG-151159 and UG-
14 160791. The calculation is based on the incremental investment in the approved
15 programs during the program year leading up to the rate year. The investment is
16 the plant placed in service associated with the HMW and Worst Circuit action
17 plan as discussed in the Prefiled Direct Testimony of Catherine A Koch, Exhibit
18 No. ___(CAK-1CT). The revenue requirement calculation includes the return on
19 this incremental investment at PSE's authorized rate of return, less accumulated
20 depreciation and deferred taxes associated with that investment (line 6 of Exhibit
21 No. ___(KJB-9)), plus the increased depreciation expense associated with the new
22 investment (line 1).

1 **Q. Please explain the Exhibit No. ___(KJB-9)**

2 A. Exhibit No. ___(KJB-9) is an example of the workpapers to be included in the
3 proposed ECRM filing, which is based on the workpapers filed in support of
4 PSE's approved Gas CRM filings. The Input section consists of rows A through H
5 which contain the approved weighted average cost of capital (lines A through C),
6 the federal income tax rate (line D), the revenue gross up percentage (line E), the
7 currently approved composite depreciation rates (line F) and an indicator for
8 whether or not the tax depreciation rates include the effects of bonus depreciation
9 (line G). Finally, the investment to be included in the revenue requirement is
10 included on line H.

11 For this filing, PSE has used its requested rate of return of 7.74%. If a different
12 rate of return is approved by the Commission in this case, the rate of return will
13 be updated at the compliance filing. In this filing PSE has used federal income
14 tax, revenue sensitive rate, and composite depreciation rates of 35%, 4.76% and
15 3.83% respectively. If needed, the composite depreciation rate will be updated at
16 compliance based on the approved depreciation rates in this proceeding. The
17 bonus depreciation indicator is set to recognize the 50% bonus depreciation that is
18 approved for 2017 investment. Finally, the investment of \$76.4 million is based
19 on information supported by Ms. Koch. This investment amount will also be
20 updated at compliance to incorporate actual expenditures and revised estimates as
21 was discussed above.

1 The calculation of the revenue requirement occurs outside of the input section, on
2 lines 1 through 35. The revenue requirement of \$10.5 million is shown on line 11
3 for Year 1. It is comprised of the depreciation expense, federal taxes on equity
4 return, return on rate base and revenue sensitive items shown on lines 1, 2, 5 and
5 7, respectively.

6 **Line 1 - Depreciation Expense:**

7 The depreciation expense of \$2.9 million on line 1 is determined using the
8 total investment of \$76.4 million on line H, multiplied by the composite
9 depreciation rate of 3.83% on line F.

10 **Line 2 – Federal Taxes on Equity Return**

11 The federal taxes on equity return calculates the incremental federal
12 income taxes associated with the program year investment. It is calculated
13 by multiplying the net rate base of \$68,523,781 (line 18) by the common
14 equity return (line B), and then applies the federal tax gross-up (one minus
15 the tax rate) to calculate the pre-tax income associated with the equity
16 return. The pre-tax income is then multiplied by the tax rate (line D) to
17 determine the federal income tax associated with the equity return
18 reflected on line 2.

19 **Line 5 – Return on Rate Base**

20 The return on rate base of \$5.3 million on line 5 is determined by
21 multiplying the net rate base of \$68.5 million on line 18 by the rate of
22 return of 7.74% on line C. The rate base on line 18 is determined by taking

1 the total investment on line H of \$76.4 million less accumulated
2 depreciation and accumulated deferred income taxes (“ADIT”).

3 Accumulated depreciation is equal to one-half of the depreciation expense
4 on line 1 and ADIT is equal to one-half of the book to tax difference (book
5 depreciation less tax depreciation times 35%) shown on line 29.

6 **Line 7 – Revenue Sensitive Items**

7 The amount for revenue sensitive items shown on line 7 is determined by
8 adding the depreciation expense and rate of return together for a total of
9 \$10.0 million shown on line 6 and dividing that total by one minus the
10 revenue sensitive rate of 4.76% on line E. The resulting \$0.5 million is
11 added to the \$10.0 million on line 6 for a total revenue requirement of
12 \$10.5 million shown on line 11.

13 In subsequent ECRM filings, the amounts in the columns labeled Year 2, Year 3
14 and so on will be used to calculate the revenue requirement associated with this
15 layer of investment, but utilizing the final actual amounts that have been true up
16 for November and December of the prior year. Additionally, the difference related
17 to Year 1 between what was set in the ECRM in the initial year based on
18 estimates for November and December and what the revenue requirement would
19 have been using actuals for November and December will be included in the 2nd
20 year filing as a true-up to the total revenue requirement.

1 **Q. Will the projections used in determining the revenue deficiency be adjusted**
2 **to actual expenditures during this proceeding?**

3 A. Yes. As discussed earlier, this exhibit has been included to show the calculations
4 that would typically be filed under the proposed mechanism and currently is based
5 entirely on the projected 2017 program year spending. PSE will update this
6 exhibit at rebuttal with actual expenditures through May 31st and estimated costs
7 for the remainder of the program year, consistent with the format that would
8 normally be filed in the July 1st filing. And during the compliance filing in this
9 proceeding, PSE will update to actuals through October and estimates for
10 November and December.

11 **Q. How will the revenue requirement be allocated to rate schedules?**

12 A. Please see the Prefiled Direct Testimony of Jon A. Piliaris, Exhibit No. ___(JAP-
13 1T) for a discussion of PSE's proposal for allocating the ECRM to rate schedules.

14 **IX. COLSTRIP UNITS 1 AND 2 DECOMMISSIONING AND**
15 **REMEDATION FUNDING**

16 **Q. Please describe PSE's proposal to fund the decommissioning and**
17 **remediation costs associated with Colstrip Units 1 and 2.**

18 A. As discussed in the Prefiled Direct Testimony of Daniel A. Doyle, Exhibit
19 No. ___(DAD-1T) consistent with the new legislation, PSE is proposing to utilize
20 the regulatory liability accounts associated with the Lower Baker and Snoqualmie
21 Treasury Grants and the existing Production Tax Credits, to address the
22 decommissioning and remediation costs associated with Colstrip Units 1 and 2.

1 The repurposing of the Treasury Grants, discussed earlier in Adjustments 6.06E
2 and Adjustment 7.12E, allows PSE to remove the remediation and
3 decommissioning costs that would typically be embedded in the approved
4 depreciation rates and helps to mitigate the negative rate impacts and
5 intergenerational inequities that would likely otherwise occur.

6 **Q. Please explain the source of the production tax credits.**

7 A. The production tax credits are tax credits PSE receives based on the amount of
8 renewable energy generated by PSE's Wild Horse and Hopkins Ridge wind
9 facilities during the first 10 years the facilities are in service. As discussed by Mr.
10 Doyle, PSE can only use these tax credits if it has taxable income on its federal
11 tax return. Due to bonus depreciation, PSE continues to have a tax loss and as a
12 result has not been able to use these credits.

13 **Q. Absent the legislation, how would customers receive the benefits associated**
14 **with the production tax credits?**

15 A. Under PSE's currently approved process, PTC's represent a future regulatory
16 liability that would be passed back to customers through tariff Schedule 95A at
17 the time PSE is able to utilize the credits on its tax return.

18 **Q. Please describe the proposed accounting that would occur if PTCs were to be**
19 **used to fund Colstrip decommissioning and remediation costs when they are**
20 **used.**

21 A. PSE proposes to reverse the PTCs as they are utilized for tax purposes and then
22 instead of filing a Schedule 95A rate change to pass the revenue requirement

1 associated with the utilized PTCs back to customers, PSE would instead credit
2 that same amount to the new FERC 108 retirement account established for
3 Colstrip 1 & 2, discussed in Adjustment 7.12. Until the PTCs are utilized on
4 PSE's tax return, they would remain in the existing PTC liability account.

5 As PSE incurs costs relating to Colstrip 1 & 2 remediation and decommissioning,
6 PSE will charge (debit) the FERC 108 account established for those actual costs.

7 **Q. How does this benefit customers?**

8 A. In addition to addressing the potential rate impacts and intergenerational equity
9 concerns discussed by Mr. Doyle, this approach will also provide the most
10 transparency, allowing Staff and interested parties to easily review the level of
11 funding available and funds spent on Colstrip remediation and decommissioning
12 in one account.

13 **X. CONCLUSION**

14 **Q. Does this conclude your testimony?**

15 A. Yes, it does.