

**EXH. KJB-17T
DOCKETS UE-170033/UG-170034
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-170033
Docket UG-170034**

**PREFILED REBUTTAL TESTIMONY
(NONCONFIDENTIAL) OF
KATHERINE J. BARNARD
ON BEHALF OF PUGET SOUND ENERGY**

AUGUST 9, 2017

PUGET SOUND ENERGY

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

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1 **PUGET SOUND ENERGY**

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

5 **I. INTRODUCTION**

6 **Q. Are you the same Katherine J. Barnard who submitted prefiled direct**
7 **testimony on January 13, 2017, and prefiled supplemental direct testimony**
8 **on April 3, 2017, on behalf of Puget Sound Energy (“PSE”) in this**
9 **proceeding?**

10 **A. Yes.**

11 **Q. What is the purpose of your rebuttal testimony?**

12 **A. This prefiled rebuttal testimony addresses the testimony submitted on behalf of**
13 **Commission Staff, the Industrial Customers of Northwest Utilities (“ICNU”),**
14 **Public Counsel, the Northwest Industrial Gas Users (“NWIGU”), Federal Energy**
15 **Agency (“FEA”), Sierra Club, and Kroger. Specifically, I will address the various**
16 **witnesses’ testimony regarding PSE’s proposed electric revenue requirement,**
17 **along with their concerns raised about the Expedited Rate Filing procedures and**
18 **the Electric Cost Recovery Mechanism.**

1 **II. COMPARISON OF PSE’S ELECTRIC BASE RATES**
2 **REVENUE DEFICIENCY AND PARTIES’ REVENUE**
3 **DEFICIENCIES**

4 **Q. Have you prepared an exhibit showing PSE’s electric base rates revenue**
5 **deficiency you are filing in this rebuttal filing?**

6 A. Yes. I have updated my electric base rates revenue deficiency for this rebuttal
7 filing in Exhibit KJB-18. I discuss the changes made since the supplemental filing
8 made on April 3, 2017 later in my testimony. Based on electric rate base of
9 \$5,186.9 billion and pro forma operating income of \$318.5 million, the electric
10 base rates revenue deficiency is \$134.0 million before allocation to wholesale
11 customers. This represents a reduction of \$10.0 million from the supplemental
12 filing submitted on April 3, 2017. Accordingly, the overall electric revenue
13 requirement deficiency of \$68.3 million reported on page 2 of Exhibit JAP-44 is
14 now \$58.3 million.

15 **Q. Have you prepared exhibits which detail the updated restating and pro**
16 **forma adjustments that PSE is proposing?**

17 A. Yes. The impact on net operating income and rate base for each PSE adjustment
18 is summarized on pages 1 through 6 of Exhibit KJB-19. I have also prepared
19 Exhibits KJB-20 and KJB-21, which contain the detail pages supporting the
20 summarized adjustments in Exhibit KJB-19. Exhibits KJB-19 through KJB-21 are
21 presented in the same format as Exhibits KJB-12 through KJB-14, and in the
22 same format as Ms. Cheesman’s Exhibit MCC-2. Exhibit KJB-22 provides the
23 updated Exhibit A-1 Power Cost Baseline Rate for use in the Power Cost

1 Adjustment (“PCA”) Mechanism.¹ Finally, Exhibit KJB-23 provides an additional
2 overview of all electric adjustments as to whether they are contested or
3 uncontested and the effect on net operating income, rate base, and the contribution
4 to the base rates revenue deficiency when comparing the results between PSE and
5 other parties. Each of these adjustments is explained by reference to the actual
6 adjustment page as listed below. PSE requests that the Commission accept the
7 adjustments included in these exhibits as presented by PSE.

8 **Q. Have you prepared a reconciliation between the electric base rates revenue**
9 **deficiency filed by PSE and the revenue deficiency/surplus filed by other**
10 **parties?**

11 A. Yes. Table 1 below highlights the differences between PSE ‘s supplemental filing,
12 PSE ‘s rebuttal filing and the opposing parties’ filings on June 30, 2017.

¹ As well as the impact on revenue requirement for the contingent calculation related to the Microsoft special contract approved in Docket UE-161123.

Table 1

Comparison of Electric Base Rates Revenue Deficiency by Adjustment Filed by PSE and Intervenors					
Line	Adjustment	PSE	Staff	Public Counsel	ICNU
			(\$000 Thousands)		
1	PSE Supplemental Filing Base Rates Deficiency	\$ 144,032			
2					
3	<u>PSE Rebuttal Changes:</u>				
4	Credit Card Processing	(1,740)			
5	Working Capital	3,715			
6	Remove Fixed Production	12,944			
7	OATT Revenue	(1,712)			
8	Power Costs	(23,075)			
9	Miscellaneous Adjustments	(129)			
10	Subtotal Rebuttal Changes	(9,997)			
11					
12	PSE Rebuttal Filing Base Rates Deficiency	\$ 134,035	\$ 134,035	\$ 134,035	\$ 134,035
13					
14	<u>Contested Issues:</u>				
15	Rate of Return on Actual Results of Operation		(30,800)	(38,292)	(28,303)
16	Temperature Normalization		(4,895)		
17	Depreciation Study		(25,189)	(27,329)	(21,999)
18	Regulatory Asset-Colstrip		(7,750)		
19	ISWC and RB Adjustment		(10,748)	(4,296)	(4,296)
20	Colstrip 1 & 2 EOL Adjustment				17,030
21	PTC Regulatory Liability Amort.				(46,012)
22	Plant Held For Future Use			(51)	(5,895)
23	Power Costs		3,467	22,760	10,162
24	Storm Damage		(16,288)	(4,221)	(2,707)
25	Energy Imbalance Market		(6,284)	(38)	(28)
26	White River		(5,092)	31	191
27	Transfer of Hydro Treasury Grants in Rate Base		6,668	(43)	(4,161)
28	Production Adjustment		(2)	(11,442)	(11,559)
29	Net Operating Loss Carryforward				(8,842)
30	Other Adjustments		2,644	(383)	1,238
31	Total Difference		(94,267)	(63,304)	(105,183)
32					
33	Adjusted Base Rates Revenue Deficiency Per Intervenor		\$ 39,768	\$ 70,731	\$ 28,852

2 **Q. What are the major differences between PSE's electric revenue deficiency**
3 **and the parties' electric revenue deficiency?**

4 A. Included in Exhibit KJB-23 is a comparison of the revenue deficiencies by
5 adjustment currently filed by PSE and opposing parties. The major differences
6 between PSE and opposing parties are (i) capital structure, (ii) return on equity
7 embedded in the rate of return, and (iii) the other differences highlighted in
8 Table 1 above. The capital structure and return on equity are discussed by

1 Mr. Doyle and Dr. Morin in their prefiled rebuttal testimony, Exhibit DAD-7T
2 and Exhibit RAM-12T, respectively. The other differences will be discussed in
3 the relevant pro forma or restating adjustment discussions, which occur later in
4 my testimony.

5 **Q. Are you aware of any changes related to the electric revenue requirement**
6 **presentations of Commission Staff?**

7 A. Yes. During discovery, PSE received Commission Staff's Response to PSE Data
8 Request Nos. 27 and 28, which reflect revisions and corrections to Commission
9 Staff's working capital calculation as well as to Commission Staff's electric
10 depreciation study adjustment that affected Commission Staff's electric revenue
11 requirement filed on June 30, 2017. Commission Staff's response to PSE's data
12 request provided updated work papers for Exhibits BAE-2 and BAE-3, as well as
13 Exhibits MCC-2, MCC-3 and MCC-5. I have provided an excerpt of Commission
14 Staff's response to PSE Data Request No. 27 as Exhibit KJB-24. I have also
15 provided Commission Staff's Response to PSE Data Request No. 17 in
16 Exhibit KJB-25, which provides an explanation for Commission Staff's change to
17 their electric depreciation study adjustment. Ms. Free discusses and provides an
18 excerpt from Commission Staff's Response to PSE's Data Request No. 28 which
19 outlines the Commission Staff's changes related to the working capital
20 calculation. PSE is providing these data request responses because they illustrate
21 the need for a correction to Commission Staff's electric depreciation study and to
22 also illustrate that PSE and Commission Staff have many fewer differences in

1 position related to working capital once Commission Staff's Response to PSE
2 Data Request Nos. 27 and 28 are taken into account versus what is reflected in
3 Table 1 above.

4 III. MULTI-YEAR RATE PLAN

5 **Q. How do you respond to Public Counsel's testimony regarding PSE's**
6 **evaluation of growth in expenses over the rate-plan period?**

7 A. Public Counsel witness Brosch questions the "per customer" comparison of
8 expenses presented as Tables 1, 2, and 3 in my prefiled direct testimony,
9 Exhibit KJB-1T, and opines that the comparison should have been on growth in
10 expenses because the use of expense per customer "dilutes the apparent rate of
11 expense growth."² His criticism is surprising considering Public Counsel took the
12 opposite view in 2013. In the 2013 decoupling case,³ Public Counsel criticized the
13 use of growth in actual expenses rather than the "per customer" figures that PSE
14 had originally used to support the K-Factor figures that were part of the multi-
15 year rate plan.

16 Regardless, whether comparing total non-production operations and maintenance
17 ("O&M") expenses in total or on a per customer basis, the tables in my prefiled
18 direct testimony do demonstrate that the annual growth rate in expenses during
19 the rate plan period were lower than the historical growth trend in PSE's non-
20 production O&M and are in line with the goals established for the rate plan.

² Brosch, MLB-1T at 21:9.

³ Docket UE-121697/UG121705, Public Counsel witness Dittmer at 5-13.

1 Between 2006 and 2011, PSE's growth in approved non-production expense
2 levels⁴ (on a per customer basis) was 3.8 percent on a combined basis (4.7 percent
3 for electric and 2.2 percent for gas)⁵. PSE's actual non-production O&M expenses
4 in total were growing at an even faster rate (5.4 percent) during that period.

5 Therefore, no matter which way you look at it, both the 1.2 percent growth in cost
6 per customer and the 2.0 percent growth in total costs reported in Table 1 of my
7 prefiled direct testimony compare favorably to PSE's historical trend.

8 Additionally, Mr. Brosch makes an assessment that PSE's ability to control costs
9 below the general level of inflation is "not exemplary."⁶ He bases his assessment
10 on his comparison of PSE's annual growth in expenses of 2 percent to the
11 *national* Gross Domestic Product Price Index (GDPPI) figure of 1.7 percent. This
12 comparison is not fully representative. Mr. Brosch should have considered
13 regional information to reflect that PSE's operations are solely located in western
14 Washington. As I addressed in my prefiled direct testimony, the growth in the
15 Seattle-Tacoma-Bremerton Consumer Price Index (CPI) has been consistently
16 higher than the national average for the last several years.⁷

⁴ PSE utilized the non-production O&M expenses as approved in PSE's 2006 and 2011 GRCs to measure historical growth in expenses for comparison purposes as this element of the K-Factor analysis was substituted with CPI less a productivity factor.

⁵ Dockets UE-121697/UG-121705, Barnard, Exh. KJB-16.

⁶ Brosch, MLB-1T at 22:5.

⁷ Barnard, Exh. KJB-1T at 8:9-12.

1 **Q. Mr. Brosch refers to PSE's proposed increase in base rates of 7.3 percent for**
2 **electric and 5.2 percent for gas operations to suggest that there has not been**
3 **an improvement in overall cost structure.⁸ Do you agree?**

4 A. No. Mr. Brosch is using the wrong numbers. He disregards the overall rate impact
5 to customers provided in the Prefiled Supplemental Testimony of Jon A. Piliaris,
6 Exhibit JAP-34T. Public Counsel's witness has chosen to ignore the decreases in
7 rates that will simultaneously occur at the conclusion of this rate case when
8 several of the rider schedules are set to zero as was discussed at length in
9 Mr. Piliaris' prefiled direct and supplemental testimonies. The 7.3 percent
10 increase in electric is compared to base rates established in the 2011 general rate
11 case. As a result, Mr. Brosch fails to recognize that a large part of this increase
12 was part of the K-Factor revenues that will be discontinued now that the rate plan
13 has concluded. Additionally, Mr. Brosch is ignoring the impact of the updated
14 depreciation study, which is a significant portion of the requested increase in
15 electric rates. The overall impact of the supplemental filing, therefore, represents
16 a decrease in natural gas rates and a modest increase in electric rates considering
17 the depreciation study.

⁸ Brosch, MLB-1T at 22:13-16.

1 **Q. How do you respond to Mr. Brosch’s criticism that PSE did not propose a**
2 **Multi-Year Rate Plan or develop a K-Factor or attrition adjustment in its**
3 **direct case?⁹**

4 A. Once again, it is quite surprising to hear this from Public Counsel, particularly
5 since Public Counsel did not support the rate plan or the use of the K-Factor in the
6 2013 case, nor to my knowledge has Public Counsel been supportive of attrition
7 adjustments filed by other utilities.

8 **IV. UNCONTESTED ELECTRIC ADJUSTMENTS**
9 **BETWEEN PSE AND PARTIES**

10 **Q. Would you please provide a list of all electric and common adjustments that**
11 **are uncontested between PSE and the parties?**

12 A. Yes. The following is a list of adjustments that are uncontested between PSE and
13 the parties.

14 **Table 2. Uncontested Adjustments**

Adjustment	NOI	Rate Base
Actual Results of Operations	\$401,002,972	\$5,153,204,462
KJB-20.01 - Revenues and Expenses	\$(29,139,114)	
KJB-20.03 - Pass-through Rev and Expenses	\$(1,000,540)	
KJB-20.04- Federal Income Tax	\$(27,023,239)	
KJB-20.05 - Tax Benefit of Proforma Interest	\$54,280,587	
KJB-20.07 - Normalize Inj & Damages	\$69,387	
KJB-20.08 - Bad Debt	\$681,065	
KJB-20.09 - Incentive Pay	\$(109,903)	

⁹ Brosch, MLB-1T at 38:13-21.

Adjustment	NOI	Rate Base
KJB-20.10 - D&O Insurance	\$16,141	
KJB-20.11 - Interest on Customer Deposits	\$(176,606)	
KJB-20.13 - Deferred G/L on Prop Sales	\$171,200	
KJB-20.14 - Property & Liability Ins	\$66,147	
KJB-20.16 - Wage Increase	\$(1,357,716)	
KJB-20.17 - Investment Plan	\$(96,705)	
KJB-20.18 - Employee Insurance	\$(121,751)	
KJB-20.20 – Payment Processing Costs	\$(2,010,221)	
KJB-20.21 - South King Service Center	\$434,046	\$15,915,060
KJB-20.22 - Excise Tax and UTC Filing Fee	\$10,262	
KJB-21.02 - Montana Electric Tax	\$145,305	
KJB-21.03 - Wild Horse Solar	\$137,890	\$(1,969,341)
KJB-21.04- ASC 815 (formerly SFAS 133)	\$(41,672,584)	
KJB-21.06 - Reg Assets and Liabilities	\$1,736,212	\$(44,085,326)
KJB-21.07 - Glacier Battery Storage	\$(145,490)	\$2,842,787
KJB-21.09 - Goldendale Capacity Upgrade	\$2,156	\$18,140,954
KJB-21.10 - Mint Farm Capacity Upgrade		\$19,004,590

1 **Q. Are there uncontested adjustments in which PSE and other parties differ?**

2 A. Yes. Below is a list of uncontested adjustments in which PSE and other parties
3 differ and an explanation as to why PSE’s adjustment has changed since its
4 original filing or why the adjustment differs from other parties’ adjustments.

5 **A. Tax Benefit of Proforma Interest, Adjustments KJB-20.05 and SEF-**
6 **15.05**

7 Parties do not contest the manner in which the tax benefit of interest is calculated.
8 However, rate base is a factor in determining the tax benefit of interest. Therefore,

1 the total amount of this adjustment will differ between PSE and other parties
2 where there are differences associated with rate base items.

3 **B. Payment Processing Costs, Adjustments KJB-20.20 and SEF-15.20**

4 PSE has accepted the proposals of Commission Staff and Public Counsel to
5 lengthen the Payment Processing Deferral from one year to three years.¹⁰ ICNU
6 and NWIGU have indicated they are neutral related to this adjustment.¹¹
7 Therefore, this adjustment is no longer contested and the change to net operating
8 income for this adjustment is a decrease of \$2,010,221 for electric and \$1,449,117
9 for natural gas operations.

10 **C. Montana Electric Energy Tax, Adjustment KJB-21.02**

11 Adjustment KJB-21.02 relies on the generation produced in the AURORA model
12 for the Colstrip facility. Parties do not contest the manner in which this
13 adjustment is calculated. Therefore, any differences between PSE and the parties
14 for this adjustment would be solely due to changes made to the Power Cost
15 Adjustment, Adjustment KJB-21.01, and so this adjustment can be considered an
16 uncontested adjustment.

¹⁰ Hancock, Exh. CSH-1CT at 29:1-2; Smith, RCS-1CT at 68:12-13.

¹¹ Mullins, Exh. BGM-3 at 1:21.

1 **D. Changes by PSE in Supplemental Testimony Ignored by ICNU**

2 **Q. Are there other adjustments to electric operations where ICNU and NWIGU**
3 **differ from PSE that were not described as differences by Mr. Mullins?**

4 A. Yes. After reviewing Mr. Mullins' work papers, it became apparent that there are
5 other adjustments to electric operations in which ICNU and NWIGU differ from
6 PSE but not described as differences by Mr. Mullins. It appears that Mr. Mullins
7 has ignored the updates made by PSE in its supplemental filing and did not
8 specifically accept or reject these updates.

9 **Q. What adjustments were updated at supplemental and ignored by**
10 **Mr. Mullins?**

11 A. The following electric adjustments were changed in PSE's supplemental filing
12 made on April 3, 2017, for the reasons discussed in my prefiled supplemental
13 testimony, Exhibit KJB-10T:

14 KJB-13.05 Tax Benefit of Proforma Interest (remains uncontested)
15 KJB-13.08 Bad Debt Expense (remains uncontested)
16 KJB-13.09 Incentive Pay (remains uncontested)
17 KJB-13.11 Interest on Customer Deposits (remains uncontested)
18 KJB-13.16 Wage Increase (remains uncontested)
19 KJB-13.17 Investment Plan (remains uncontested)
20 KJB-14.01 Power Costs
21 KJB-14.02 Montana Electric Energy Tax (remains uncontested)
22 KJB-14.05 Storm Damage
23 KJB-14.11 White River
24 KJB-14.13 Production Adjustment

25 I have indicated above which of these adjustments are uncontested in this
26 proceeding. For the remaining adjustments indicated, no party provided testimony
27 contesting these adjustments, including Mr. Mullins for ICNU and NWIGU.

1 Absent testimony directly contesting these adjustments, PSE must assume that it
2 was an oversight on the part of Mr. Mullins. Therefore, any differences in the
3 proposed revenue requirement between PSE and ICNU and NWIGU resulting
4 from these adjustments should be rejected and PSE's adjustment should be
5 approved.

6 **V. CONTESTED ELECTRIC AND**
7 **CERTAIN COMMON ADJUSTMENTS**

8 **Q. Would you please describe the difference between PSE and other parties on**
9 **the contested adjustments?**

10 A. Yes. Below is a description of electric only and certain common contested
11 adjustments and discussion why the Commission should adopt the adjustments as
12 proposed by PSE. The gas only and remaining common adjustments are discussed
13 in the Prefiled Rebuttal Testimony of Susan E. Free, Exhibit SEF-12T.

14 A. **Temperature Normalization, Adjustment KJB-20.01**

15 **Q. Please explain the difference between PSE and Commission Staff for**
16 **Temperature Normalization, Adjustment KJB-20.01.**

17 A. Commission Staff recommends this adjustment be calculated using the schedule
18 level weather normalization.¹² Please see the Rebuttal Testimony of Dr. Chun K.
19 Chang, Exhibit CKC-3T, for the reasons why the Commission should disregard
20 Commission Staff's recommendation and accept PSE's adjustment as proposed.

¹² Liu, Exh. JL-1CT at 3:1-4.

1 This adjustment has not been changed since PSE's supplemental filing and
2 increases electric net operating income by \$17,527,344.

3 **B. Depreciation Study, Adjustment KJB-20.06**

4 **Q. Please explain the differences between the depreciation expense adjustments**
5 **proposed by Commission Staff witness Mr. McGuire and PSE.**

6 A. As explained in the Prefiled Rebuttal Testimony of Mr. John J. Spanos, Exhibit
7 JJS-4T, Mr. McGuire has incorrectly applied the undepreciated balance over the
8 entire life of the plant and, as a result, proposes only a \$1.4 million increase per
9 year in the depreciation expense associated with Colstrip Units 1 and 2.
10 Mr. McGuire creates a \$127 million reserve imbalance based on a "theoretical"
11 level of depreciation that he believes should have been collected between 1975,
12 when the units commenced service, and 2017, when the new depreciation rates
13 will be effective.¹³ His proposal includes amortization of the alleged imbalance (a
14 regulatory asset) over the previously assumed depreciation life, (i.e., until 2035),
15 excluding the regulatory asset from rate base and expressly denying any carrying
16 charges. Although Mr. McGuire states this approach is "fair" for customers,¹⁴ it is
17 punitive to PSE and its shareholders because his approach neither includes any
18 carrying charges on the regulatory asset nor includes the regulatory asset in rate
19 base. Under Mr. McGuire's approach, PSE bears the entire burden associated with
20 the unrecovered plant.

¹³ See generally McGuire, Exh. CRM-1T at 21.

¹⁴ McGuire, Exh. CRM-1T at 16:22.

1 **Q. Does PSE agree with Mr. McGuire's assessment and proposed treatment of**
2 **the alleged imbalance?**

3 A. No. I am surprised that Mr. McGuire would propose this punitive approach on
4 PSE and its shareholders when the alleged depreciation imbalance to which he
5 refers results from proposals by Commission Staff and Public Counsel in PSE's
6 2007 general rate case to extend the depreciable life of Colstrip Units 1 and 2 to
7 60 years.

8 **Q. Please elaborate on the proposal by Commission Staff and Public Counsel**
9 **that created the claimed imbalance.**

10 A. In PSE's 2007 general rate case, PSE filed a depreciation study that proposed a
11 44-year service life for Colstrip Unit 1 and a 45-year service life for Colstrip
12 Unit 2.¹⁵ Prior to that study, the service life for Colstrip was 40 years.

13 In response testimony in the 2007 general rate case, Public Counsel recommended
14 a 60-year service life for all Colstrip units, which would result in retirement in
15 2035 for Colstrip Units 1 and 2.¹⁶ Similarly, Commission Staff witness William
16 Weinman testified that although he generally agreed with the remaining life and
17 life span concepts used by PSE's depreciation expert to determine depreciation
18 rates for production plant as well as the net salvage estimates, he likewise
19 proposed a 60-year plant life for the Colstrip units.¹⁷

¹⁵ See Docket UE-072300, Clarke, Exh. CRC-1T.

¹⁶ See Docket UE-072300, King, Exh. CWK-1T at 3.

¹⁷ See Docket UE-072300, Weinman, Exh. WHW-1T at 7-10.

1 In rebuttal, PSE continued to support a 45-year service life for the Colstrip units.
2 PSE witness Michael Jones testified that compliance with environmental laws and
3 regulations, such as the Clean Air Act, EPA's Clean Air Visibility Rule, and
4 Montana's Mercury Emission Control Rule, may affect the useful life of coal-
5 fired units such as Colstrip.¹⁸

6 After rebuttal testimony was filed, PSE and parties to the proceeding entered into
7 several settlement agreements addressing various issues raised in the general rate
8 case. As one piece of this compromise, the parties agreed to extend the
9 depreciable lives of the Colstrip units to 60 years, as proposed by Commission
10 Staff and Public Counsel.¹⁹ It is the extension of the depreciable lives for Colstrip
11 Units 1 and 2 to 2035 that has created the claimed imbalance that Mr. McGuire
12 tries to correct.

13 **Q. Is it appropriate for Commission Staff to punish PSE for agreeing to the**
14 **longer Colstrip depreciation proposed by Commission Staff and Public**
15 **Counsel in the 2007 general rate case as part of the settlement agreement?**

16 A. No. It is duplicitous for Commission Staff to argue for a longer depreciation
17 schedule in the 2007 general rate case (presumably to lower rates for customers)
18 and now seek to punish PSE for agreeing in settlement to the proposal made by
19 Commission Staff and Public Counsel. It also would be poor public policy for the

¹⁸ See Docket UE-072300, Jones, Exh. MLJ-15T at 8-13.

¹⁹ See Docket UE-072300, Exhibit Joint-7T, Joint Testimony Re Electric and Natural Gas Revenue Requirements.

1 Commission to allow such behavior, which will have a chilling effect on
2 settlement efforts now and in the future.

3 **Q. Does any party directly support PSE’s approach for higher depreciation for**
4 **Colstrip Units 1 and 2 to recognize that the life is shorter than previously**
5 **recognized in PSE’s depreciation rates?**

6 A. Yes. It appears that Public Counsel recognizes the need to recover the
7 undepreciated plant over the remaining life of Colstrip Units 1 and 2.²⁰ Although
8 Public Counsel’s proposed depreciation study has numerous flaws, as identified in
9 the Prefiled Rebuttal Testimony of Mr. John J. Spanos, Exhibit JJS-4T, Public
10 Counsel accepts PSE’s proposed depreciable life for Colstrip Units 1 and 2 and
11 appropriately does not include a write-down of the assets.

12 **Q. Does PSE agree with Sierra Club’s statement that PSE should bear some of**
13 **the costs associated with its “poor planning” for the shutdown of Colstrip**
14 **Units 1 and 2?²¹**

15 A. No. As previously stated, PSE proposed to set depreciation rates at a level that is
16 consistent with the actual planned closing of Colstrip Units 1 and 2 in the 2007
17 general rate case, but PSE’s proposed depreciation rates were opposed by
18 Commission Staff and Public Counsel who sought to keep rates lower for
19 customers by extending the service lives of the facilities. PSE’s decision to enter

²⁰ See generally McCullar, Exh. RMM-1T.

²¹ Hausman, Exh. EDH-1T at 6:5-6.

1 into a broad settlement of multiple issues in the 2007 case, which included
2 agreeing to the 60-year depreciation life proposed by Commission Staff and
3 Public Counsel, should not be characterized as “poor planning,” and PSE should
4 not be punished for its decision to compromise on a contested issue.

5 Further, Sierra Club acknowledges that, although PSE witness Michael Jones
6 testified accurately about the environmental pressures the Colstrip units were
7 likely to face in the years ahead, he “could not have anticipated the other
8 economic factors that have compounded the economic distress for coal plants in
9 the decade since the 2007 rate case.”²² Thus, this is not a case of “poor planning”
10 on the part of PSE.

11 **Q. Does PSE agree with Commission Staff’s adjustment to the Colstrip**
12 **Units 1 and 2 depreciation rates?**

13 A. No. As discussed in the Prefiled Rebuttal Testimony of John J. Spanos,
14 Exhibit JJS-4T, Mr. McGuire’s methodology for addressing the under-depreciated
15 balance for Colstrip Units 1 and 2 is not consistent with traditional depreciation
16 and should be rejected. PSE has left the proposed depreciation expenses
17 associated with the Colstrip Units 1 and 2 unchanged from the original proposal.
18 Adopting the depreciation study and the resulting rates, including PSE’s
19 adjustment to exclude net salvage, which was deemed reasonable by Mr. Spanos,
20 is fair to customers because these customers are for the most part the same

²² Hausman, Exh. EDH-1T at 12:16-18.

1 customers who have benefited from the lower depreciation expense for the past
2 nine years.

3 **Q. Does PSE agree that Mr. McGuire’s Exhibit CRM-3 is “correcting” the**
4 **depreciation reserve balance?**²³

5 A. No. Correcting the depreciation reserve balance implies that there was an error in
6 booking the depreciation expense over the past several years, which is not the
7 case. PSE followed the depreciation rate proposed by Commission Staff and
8 Public Counsel, agreed to in settlement, and approved by the Commission in the
9 2007 general rate case. Although Commission Staff may now regret its proposal
10 from that case, it resulted in the depreciation rates that have since been included
11 in PSE rates. PSE cannot unilaterally change the depreciation rates. Therefore, the
12 reserve adjustment as proposed by Mr. McGuire is inappropriate.

13 **Q. Mr. McGuire suggests that his approach of “correcting the plant in service**
14 **value for Colstrip Units 1 and 2” better adheres to the principles of “fairness**
15 **and balance.”**²⁴ **Does PSE agree?**

16 A. No. Mr. McGuire’s proposal assumes that it is unfair to have current customers
17 pay the unrecovered balance of Colstrip Units 1 and 2, but the majority of these
18 customers received the benefit of lower rates resulting from the longer
19 depreciation schedule over the past nine years. As addressed in the Prefiled
20 Rebuttal Testimony of Mr. John J. Spanos, Exhibit JJS-4T, it is more appropriate

²³ McGuire, Exh. CRM-1T at 5:13.

²⁴ McGuire, Exh. CRM-1T at 16:13-18.

1 for customers to pay modestly more for the service associated with these assets
2 than to require future customers to pay for assets from which they receive no
3 benefit.

4 Further, under Mr. McGuire's proposal, PSE will not recover the "\$127 million of
5 reserve imbalance" for thirteen additional years beyond the life of Colstrip
6 Units 1 and 2. Additionally, Mr. McGuire proposes the use of a regulatory asset
7 but neither includes that asset in rate base nor allows PSE to recover any carrying
8 charges. This proposal does not meet the principles of "fairness and balance" that
9 Mr. McGuire purports to follow. Essentially, Mr. McGuire proposes customers
10 receive an interest free loan for twelve years and PSE receives no compensation
11 for the additional delay in recovery.²⁵ This seems particularly punitive to PSE
12 when Mr. McGuire recognizes that the existing rates were not wrong based on the
13 information known at the time and, in fact, were extended based on Commission
14 Staff's proposal.²⁶

15 It is unclear why PSE's investors should be punished by extended recovery
16 further into the future with no carrying costs or inclusion in rate base. It is also
17 surprising that Mr. McGuire chooses to remove the investment now, while the
18 units are still in service and providing customers benefits. If the regulatory asset
19 as proposed by Mr. McGuire were included in rate base, at least PSE would have

²⁵ Please see the Prefiled Rebuttal Testimony of Daniel A. Doyle, Exh. DAD-7T, for a discussion of the additional implications of impairment accounting associated with Mr. McGuire's exclusion of carrying costs on the regulatory asset.

²⁶ McGuire, Exh. CRM-1T at 30-31.

1 the opportunity to earn a return on the investment. Mr. McGuire’s approach
2 would require PSE to take a further write down as discussed in the Prefiled
3 Rebuttal Testimony of Mr. Daniel A. Doyle, Exhibit DAD-7T.

4 **Q. Mr. McGuire supports his proposal because of the “sudden decline in service**
5 **value” due to the decision to close Colstrip Units 1 and 2 “early.”²⁷ Does PSE**
6 **agree?**

7 A. No. As discussed in the Prefiled Rebuttal Testimony of Mr. Ronald J. Roberts,
8 Exhibit RJR-30T, the notion that the plants are closing “early” is based solely on
9 the estimated life from the last depreciation study, which was part of a negotiated
10 settlement. This issue is also further discussed in the Prefiled Rebuttal Testimony
11 of Matthew R. Marcellia, Exhibit MRM-1T.

12 **Q. Do the abandonment accounting entries PSE booked support Mr. McGuire’s**
13 **assumptions?**

14 A. No. As explained in the Prefiled Rebuttal Testimony of Mr. Matthew R. Marcellia,
15 Exhibit MRM-1T, the abandonment accounting entries were recorded for
16 Generally Accepted Accounting Principles (“GAAP”) purposes only. From a
17 regulatory accounting standpoint, these entries *did not* impact plant in service

²⁷ McGuire, Exh. CRM-1T at 19:14-15.

1 because they were directly offsetting and all booked to FERC Account 101.²⁸

2 Mr. Marcelia explains in detail why Mr. McGuire's assumption is erroneous.

3 **Q. Do the legal authorities cited by Mr. McGuire support his write down of the**
4 **Colstrip Units 1 and 2 plant?**

5 A. No. Mr. McGuire references RCW 80.04.250(2),²⁹ which provides the
6 Commission the power to make revaluations of the property of any public service
7 company from time to time. However, neither case he cites that refer to this
8 statute are relevant to Colstrip. In the 1927 case to which Mr. McGuire referred,³⁰
9 although the Supreme Court recognized the statute allows for revaluation based
10 on changing condition, the Supreme Court also recognized that particular statute
11 did not apply in that case as can be seen by reading a little further in
12 Mr. McGuire's citation which provides that "the question under what conditions
13 the necessity may arise is not presented here and we do not decide it."³¹ There is
14 only *one* instance in which the Commission required an adjustment to correct a
15 reserve imbalance and that was in Docket U-86-02, in which depreciation expense
16 had been booked inconsistently with GAAP.³² In that case, Pacific Power & Light
17 had accrued accumulated depreciation only based on what it was collecting in

²⁸ Sierra Club witness Hausman reaches a similar incorrect conclusion regarding the GAAP entry which the Commission should not accept for the reasons outlined in Mr. Marcelia's testimony. *See* Hausman, EDH-1T at 17:5-10.

²⁹ McGuire, Exh. CRM-1T at 31-32.

³⁰ *State ex rel. Pac. Power & Light Co. v. Dep't of Pub. Works*, 143 Wn. 67, 254 P. 839 (1927).

³¹ 143 Wn. at 86, 254 P. at 846.

³² *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co.*, Docket U-86-02, 78 PUR.4th 84, 94-95, Second Supplemental Order at 15 (Sept. 19, 1986).

1 rates rather than utilizing the approved depreciation rates; this created the
2 inconsistency with GAAP. In contrast to the Pacific Power & Light case, PSE
3 booked its depreciation expense consistent with the depreciation rates approved
4 by the Commission in 2008, and Mr. McGuire does not provide any evidence to
5 the contrary.

6 **Q. What is the proposal of ICNU witness Mr. Mullins in Adjustment IN-1, with**
7 **respect to depreciation rates?**

8 A. Mr. Mullins proposes leaving the current depreciation rates for Colstrip
9 Units 1 and 2 in place and, at the end of the life, converting the remaining balance
10 into a regulatory asset that would be recovered through a separate surcharge,³³
11 which is actually a tracker. Mr. Spanos and Mr. Marcellia address why
12 Mr. Mullins approach is not reasonable.

13 **Q. On what basis does Mr. Mullins support his tracker proposal?**

14 A. Similar to Mr. McGuire and others, Mr. Mullins has incorrectly assumed that the
15 2022 retirement date represents an early retirement. Therefore, he applies an
16 approach similar to that used by the Oregon Public Utility Commission when
17 addressing the early closure of the Trojan Nuclear Facility. Mr. Mullins
18 recommends that the Commission follow a similar approach and allow for the
19 stranded costs to be recovered through a regulatory asset that would be collected
20 separately through a tracker and would accrue carrying costs based on long-term

³³ Mullins, Exh. BGM-1T at 6:10-12 and 20:6-11.

1 cost of debt rather than PSE's full rate of return once Colstrip Units 1 and 2 are no
2 longer in service.

3 **Q. Does Sierra Club make a similar argument?**

4 A. Yes. Sierra Club makes a similar argument but cites a decision involving
5 Humboldt Bay Unit 3, in which the California Public Utilities Commission stated
6 as follows:

7 *While Unit 3 did operate for 13 years, it will never operate again*
8 *and can no longer be considered "useful" utility plant. Unit 3 was*
9 *entered into rate base under the assumption that it would serve*
10 *customers for 30 years. Shareholders were entitled to a return and*
11 *ratepayers were liable for the full ownership cost as long as Unit 3*
12 *operated as expected.*³⁴

13 **Q. Does PSE agree that the Trojan Nuclear Facility and Humboldt Bay Unit 3**
14 **shutdowns are comparable to the shutdown of Colstrip Units 1 and 2?**

15 A. No. There are some notable differences between the two facilities and their
16 assumed life spans. Mr. Mullins claims that the Trojan Nuclear Facility shutdown
17 is "probably the best example of an early retirement of a generation plant."³⁵ He
18 provides the history of the Trojan plant, relying on the fact that the Trojan facility
19 closed seventeen years earlier than originally anticipated. What Mr. Mullins and
20 Dr. Hausman fail to recognize is that Colstrip Units 1 and 2, whether they close
21 tomorrow or close as anticipated in mid-2022, will have been in service for longer
22 than originally anticipated when the plants were placed in service. As discussed in

³⁴ Hausman, Exh. EDH-1T at 23:9-19 (quoting *Re Pac. Gas & Elec. Co.*, Application 83-09-49, Decision 85-08-046 at 15, 18 CPUC.2d 592 (Aug. 21, 1985) (emphasis added).

³⁵ Mullins, Exh. BGM-1CT at 11:10-12.

1 the Prefiled Rebuttal Testimony of Mr. Ronald J. Roberts, Exhibit RJR-30T, the
2 original anticipated life of Colstrip Units 1 and 2 was 25-30 years. As discussed
3 earlier in my testimony, the “early shut down” referenced by the other parties is
4 based solely on the 2007 settlement that actually extended the depreciable life of
5 the plant to 60 years compared to the previously approved depreciable life.

6 Colstrip Units 1 and 2 will have been in operation for over 40 years at the time the
7 new depreciation rates take effect in 2018 and by the retirement date in 2022 will
8 have been in service for more than 45 years. This is not comparable to either

9 (i) the Trojan Nuclear facility, which was originally estimated
10 to have a 36-year life (1975 to 2011) but was only in
11 service until 1993 (i.e., less than 20 years), which is
12 acknowledged by Mr. Mullins in ICNU’s Response to PSE
13 Data Request No. 6 included as Exhibit KJB-39; or

14 (ii) Humboldt Bay Unit 3, which was originally estimated to
15 have a 30-year life (1963 to 1993) but was only in service
16 until 1976 (i.e., only 13 years).

17 **Q. Mr. Mullins also provides an example about Deer Creek Mine and believes it**
18 **is similar to Colstrip Units 1 and 2. Does PSE agree?³⁶**

19 A. No. The Deer Creek Mine involved a sale of mining facilities. Therefore, the Deer
20 Creek Mine example is more comparable to PSE’s sale of the Electron Hydro
21 project in that there were unrecovered costs for those facilities after application of
22 sale proceeds. In Electron, PSE had unrecovered costs, and the Commission

³⁶ Mullins, Exh. BGM-ICT at 11:12-14.

1 allowed recovery of the regulatory asset over a four-year period.³⁷ Similar to other
2 regulatory assets, the Electron regulatory asset did not include direct carrying
3 charges but is included in PSE's rate base for ratemaking purposes.

4 **Q. Does Mr. Mullins calculate his adjustment IN-1 correctly?**

5 A. No. Mr. Mullins provides a calculation of his proposed regulatory asset with
6 carrying charges in his Exhibit BGM-6. Mr. Mullins' exhibit contains a
7 calculation error in that he only provides one-half of the carrying charges he
8 recommends. I have included Exhibit KJB-40, which shows the required
9 correction to page 1 of Exhibit BGM-6 that would be required if the Commission
10 were to accept Mr. Mullins' position, which PSE opposes.

11 **Q. Is Mr. Mullins' proposal to include those costs in a separate tracker**
12 **necessary?**

13 A. No. Although the idea of a tracker may hold some appeal because the recovery of
14 the unrecovered plant would more closely track PSE's costs, it is curious that
15 ICNU would propose a tracker considering it currently opposes the ECRM
16 because it is a tracking mechanism.

³⁷ See *In the Matter of the Petition of Puget Sound Energy For an Accounting Order Authorizing Accounting the Sale of the Water Rights and Associated Assets of the Electron Hydroelectric Project in Accordance with WAC 480-143 and RCW 80.12*, Docket UE-131099, Order 06 at ¶ 9 (Oct. 9, 2014).

1 **Q. How do you respond to Mr. Mullins' proposal to require that any capital**
2 **expenditures to plant aside from those included in the test year be included**
3 **in the separate tracker with a prudence determination required for every**
4 **asset?**³⁸

5 A. It is unnecessary to have a separate tracker to conduct the review of capital
6 expenditures at Colstrip Units 1 and 2. Plant related to Colstrip is tracked through
7 PSE's property accounting system and the information can be reviewed
8 irrespective of those assets being placed in a tracker. Similarly, the establishment
9 of retirement accounts for Colstrip, where the existing Treasury Grants and future
10 proceeds from Production Tax Credits ("PTCs") will be transferred if PSE's
11 proposal is accepted, will allow for the transparency that Mr. Mullins is
12 requesting.

13 **Q. What is Sierra Club's position regarding the appropriate depreciation rates**
14 **for the Colstrip assets?**

15 A. Sierra Club witness Dr. Ezra D. Hausman, Ph.D. has neither prepared a revenue
16 requirement analysis nor proposed a specific adjustment to PSE's revenue
17 requirement calculations. Therefore, it is unclear what Sierra Club specifically
18 proposes regarding Colstrip Units 1 and 2. Despite the lack of clarity regarding
19 Sierra Club's proposal for Colstrip Units 1 and 2, it is clear they are advocating
20 for a shorter life for Colstrip Units 3 and 4. If the life for Colstrip Units 3 and 4

³⁸ Mullins, Exh. BGM-1CT at 21:10-22:13.

1 were shortened to 2025, as suggested by Sierra Club, the impact to revenue
2 requirement would be approximately \$16 million.³⁹

3 **Q. Please explain the lack of clarity in Sierra Club’s testimony regarding**
4 **depreciation rates for Colstrip Units 1 and 2.**

5 A. Dr. Hausman neither questions the proposed depreciation life for Colstrip
6 Units 1 and 2 nor challenges PSE’s proposed depreciation study adjustment
7 directly. However, Dr. Hausman’s reference to the GAAP regulatory asset and the
8 “\$176.8 million undepreciated balance”⁴⁰ implies that there would be no change
9 to the depreciation rates for Colstrip Units 1 and 2. As discussed in the Prefiled
10 Rebuttal Testimony of Matthew R. Marcellia, Exhibit MRM-1T,⁴¹ the
11 \$176 million GAAP entry to which Mr. Hausman refers is based on the
12 assumption that the depreciation rates for Colstrip Units 1 and 2 do not change
13 from the current level. It is unclear if Mr. Hausman is making such a proposal,
14 however, it seems disingenuous to advocate for a shorter life for Colstrip
15 Units 3 and 4 and recognize the revenue requirement impact of such a change
16 while ignoring the requested change in depreciation lives for Colstrip
17 Units 1 and 2.

³⁹ Hausman, Exh. EDH-1T at 6:15-20.

⁴⁰ Hausman, Exh. EDH-1T at 22:14.

⁴¹ Marcellia, Exh. MRM-1T at 37:9 - 38:10.

1 **Q. If the Commission were to adopt PSE's proposed depreciation rates, would**
2 **Colstrip Units 1 and 2 be fully depreciated by the closure date of July 1,**
3 **2022?**

4 A. No. It is unlikely that Colstrip Units 1 and 2 will be completely depreciated by the
5 closure date of July 1, 2022, even if the Commission were to adopt PSE's
6 proposed depreciation rates. However, the net book value at that time will
7 certainly be much lower than under Commission Staff's, ICNU's and possibly
8 Sierra Club's proposals. As addressed in my prefiled direct testimony, the
9 removal of the negative salvage associated with Colstrip Units 1 and 2 from the
10 proposed depreciation rates⁴² ignores any interim salvage that may be necessary.
11 Additionally, since the proposed depreciation rates will not take effect until the
12 conclusion of this case, there will be differences because of the additional year of
13 depreciation at the lower rate during the pendency of this proceeding. I address
14 this now, not because I believe the proposed depreciation rates are incorrect, but
15 merely to recognize that depreciation studies are an approximation and there will
16 always be differences at the end of an asset's life. The goal is to be close, but they
17 will never be perfect. This is why PSE proposes to use the PTCs and hydro-
18 related Treasury Grants to address the unrecovered plant and decommissioning
19 and remediation of Colstrip Units 1 and 2.

⁴² Barnard, Exh. KJB-1T at 31.

1 **Q. Sierra Club advocates that the regulatory liabilities should not be utilized to**
2 **address undepreciated plant for Colstrip Units 1 and 2.⁴³ Does PSE agree?**

3 A. No. The application of the PTCs to address any remaining book balance at the end
4 of the units' lives is a very reasonable utilization of the PTCs once they are
5 monetized. As discussed in more detail later in this rebuttal testimony, the PTCs
6 were generated during the 2009 through 2017 period, which is the same time
7 period the recent depreciation rates that assumed a 2035 life were in effect. From
8 a generational standpoint, a reasonable matching of expense and benefits would
9 be accomplished.

10 **Q. Has any other party challenged the depreciable lives of any generation**
11 **facilities?**

12 A. No. Only the Sierra Club has challenged the proposed depreciable life for Colstrip
13 Units 3 and 4.⁴⁴

14 **Q. Does PSE agree with Sierra Club's recommendation?**

15 A. Not entirely. As discussed in the Prefiled Rebuttal Testimony of Mr. Ronald J.
16 Roberts, Exhibit RJR-30T, it may not be reasonable to retire Colstrip
17 Units 3 and 4 by 2025 based on current information. However, there certainly are
18 a number of issues that, as they continue to evolve, could impact Colstrip for
19 depreciation study purposes. For example, the Oregon law to which Sierra Club

⁴³ Hausman, Exh. EDH-1T at 39:10-14.

⁴⁴ *Id.* at 6:15-17.

1 refers⁴⁵ requires Oregon utilities to have no coal in their portfolio by 2030. Two
2 of the five co-owners of Colstrip Units 3 and 4 provide electric service in Oregon,
3 and PSE does not know if, or how, the Oregon law could affect the operations of
4 these co-owners. It is possible that the Oregon law could result in a shorter life for
5 Colstrip Units 3 and 4 than currently reflected in the proposed depreciation study.
6 Additionally, other unknowns, such as the impact of a carbon tax at either the
7 federal or the state level (in Montana or Washington) and the continuation of low
8 gas prices could likely affect the economics of Colstrip Units 3 and 4 for all
9 owners and could lead to an earlier retirement as well.

10 Due to this uncertainty, PSE requested that Mr. Spanos provide two alternate
11 depreciation schedules for Colstrip Units 3 and 4—one based on a closure date of
12 December 31, 2025 (i.e., similar to the date requested by Sierra Club) and the
13 other based on a closure date of December 31, 2029 (i.e., the date the Oregon law
14 goes into effect). Exhibit KJB-26 provides side-by-side comparisons of the
15 depreciation adjustment under all three scenarios and the impact on revenue
16 requirement of the Sierra Club proposal. As reflected on line 41 of the exhibit,
17 shortening the life to 2030 would increase PSE’s revenue requirement an
18 additional \$5,477,968 compared to the depreciation life of 2025 which would
19 increase PSE’s revenue requirement by an additional \$13,956,847.

⁴⁵ *Id.* at 31:11-12.

1 **Q. Does this mean that PSE is proposing to close Colstrip Units 3 and 4 earlier**
2 **than 2035?**

3 A. No. As discussed in both Mr. Roberts’ prefiled direct and rebuttal testimonies,
4 there are other co-owners of Colstrip Units 3 and 4. PSE cannot unilaterally
5 choose to close those units. Additionally, a depreciation study *does not* dictate the
6 actual closure of any plant or facility; it is merely used for estimating the
7 “economic life” of the plant.

8 **Q. Are there benefits to customers of considering a shorter depreciation life**
9 **than 2035 for Colstrip Units 3 and 4?**

10 A. Yes, particularly with the uncertainty of a possible carbon tax or cap and trade
11 mechanism in Washington and the Western U.S. The primary benefit of adopting
12 a shorter depreciation life is there is less risk of under recovery of the asset during
13 the asset’s service life, relieving future customers from paying for an asset from
14 which they received no benefits. If the Commission were to utilize the shorter life
15 (i.e., a closure date of 2025) for Colstrip Units 3 and 4, there is far less risk of
16 unrecovered plant than under the current depreciation study’s 2035 life, or even
17 the next best estimate of December 31, 2029.

18 A benefit of utilizing the December 2029 scenario is that PSE’s depreciation rates
19 would be more closely aligned with the 2032 economic life for Colstrip
20 Units 3 and 4 that the Commission approved for PacifiCorp in Docket UE-152253
21 and would be aligned with the Oregon legislation mandating no coal in Oregon by
22 2030.

1 **Q. Is PSE changing its position regarding the depreciation life for Colstrip**
2 **Units 3 and 4?**

3 A. No. PSE provides this analysis to recognize that there is significant uncertainty
4 surrounding the remaining life of Colstrip Units 3 and 4. Utilizing a shorter
5 depreciation life reduces the risk of under recovery of those assets during the life
6 of the facility. However, as mentioned in regard to Colstrip Units 1 and 2, even if
7 the depreciation life is reset to the end of 2025, there will likely be some level of
8 unrecovered plant associated with these facilities if the plants were to close at the
9 end of 2025.

10 **Q. Does PSE have suggestions as to how to address the unrecovered plant that is**
11 **likely to remain?**

12 A. Yes. Placing the PTCs in a separate retirement account as they are monetized, as
13 opposed to passing them back through Schedule 95A, is the best solution for
14 addressing the uncertainties associated with the Colstrip units. Allowing the entire
15 balance of monetized PTCs to be booked to a Colstrip retirement account and
16 reflecting the retirement account as a reduction to rate base provides the added
17 benefit of not directly impacting customers rates, while still addressing the under
18 depreciation that occurred between 2009 and 2017 and that could occur if the
19 economics of Colstrip Units 3 and 4 change such that the actual depreciation life
20 ends up being shorter than the 2035 life currently estimated in the depreciation
21 study.

1 **Q. Please summarize the testimony of NWEAC witness Thomas Michael Power**
2 **and his characterization of PSE’s depreciation adjustment?**

3 A. Mr. Power’s testimony includes technical errors and broad generalizations that
4 cloud an already complicated issue, although in the end he does not oppose PSE’s
5 proposed use of hydro-related Treasury Grants or Production Tax Credits to
6 address unrecovered costs associated with Colstrip Units 1 and 2.⁴⁶ Mr. Power
7 claims that PSE has proposed to “zero out the Colstrip 1 and 2 depreciation
8 account”⁴⁷; he insinuates that PSE’s existing depreciation rates did not include
9 any costs for decommissioning and remediation⁴⁸ all to reach his conclusion that
10 it was a “lack of planning and preparation” that has created the situation with
11 Colstrip Units 1 and 2 and that these lessons should be instructive for Colstrip
12 Units 3 and 4.⁴⁹

13 **Q. Please explain why Mr. Power’s statement about PSE setting the**
14 **depreciation rate for Colstrip Units 1 and 2 to zero is incorrect?**

15 A. Mr. Power has misquoted my testimony where I refer to removing the negative
16 net salvage amount from the depreciation rates and instead he claims the proposed
17 depreciation rate for the Colstrip Units 1 and 2 are zero; this is simply not true.
18 Additionally, he claims that the existing depreciation rates included zero costs for
19 decommissioning and remediation, which is also untrue. Mr. Power has managed

⁴⁶ Power, Exh. TMP-1T at 15:17-18.

⁴⁷ *Id.* at 11:6-9.

⁴⁸ *Id.* at 17:21-22.

⁴⁹ *Id.* at 18:17-18.

1 to gloss over the fact that current depreciation rates were collecting some level of
2 net salvage, albeit clearly too little in light of the changing regulations associated
3 with the Coal Combustion Residuals (“CCR”) rules. He is correct that PSE did
4 recognize some level of pond remediation would be necessary as reflected in the
5 Asset Retirement Obligation (“ARO”) discussion; however, the CCR rules
6 became law in 2015, which changed the landscape and resulted in far more
7 prescriptive rules as addressed in the Prefiled Direct Testimony of Mr. Ronald J.
8 Roberts, Exhibit RJR-1CT. To utilize these changing circumstances to imply it
9 was poor planning is not an accurate assessment of the situation surrounding the
10 Colstrip units.

11 **Q. Do other parties contest areas of the depreciation study that are not related**
12 **to Colstrip?**

13 A. Yes. As stated in Section II above, even though Commission Staff claimed to only
14 contest Colstrip Units 1 and 2, the depreciation adjustment that Commission Staff
15 filed on June 30, 2017, differed from PSE on amounts related to Colstrip
16 Units 3 and 4. During discovery, Commission Staff identified that inadvertent
17 changes had been made to its depreciation study work papers for Colstrip
18 Units 3 and 4. Exhibits KJB-24 and KJB-25 contain Commission Staff’s
19 explanation of the error and the recalculation of the depreciation study adjustment
20 and the affected revenue requirement exhibits. If Commission Staff’s
21 recommended change is considered, then Public Counsel will be the only party

1 who contested and had differing items within PSE's proposed depreciation study
2 that are related to issues other than Colstrip Units 1 and 2.

3 **Q. Does PSE agree with the modifications to the depreciation adjustment**
4 **proposed by Public Counsel?**

5 A. No. Not only are the depreciation rates proposed by Ms. McCullar inadequate, as
6 addressed in the Prefiled Rebuttal Testimony of Mr. John J. Spanos, Exhibit JJS-
7 4T, Mr. Smith's depreciation adjustment shown on Exhibits RCS-3 and RCS-4,
8 Schedule C-12 appears to have several errors and therefore should be rejected.

9 **Q. Please describe PSE's concerns with Mr. Smith's Schedule C-12?**

10 A. According to Mr. Smith's testimony,⁵⁰ his depreciation adjustment is based on the
11 new depreciation rates being recommended by Ms. McCullar; however,
12 Mr. Smith's work papers and the amounts included in his proposed revenue
13 requirement do not appear to support that statement. For example, Ms. McCullar's
14 testimony states that she has accepted Mr. Spanos' proposed depreciation rates for
15 common equipment;⁵¹ therefore, one would expect Mr. Smith's adjustment to be
16 the same as that proposed by PSE. However, that is not the case when reviewing
17 his Schedule C-12 because he removes \$3,353,841 (\$2,253,110 for electric and
18 \$1,100,730 for gas) of test period depreciation expense without any explanation in
19 his testimony. Based on Public Counsel's Response to PSE Data Request

⁵⁰ Smith, Exh. RCS-1CT at 40:12-21.

⁵¹ McCullar, Exh. RMM-1T at 5:Table 1.

1 No. 12,⁵² it appears that Mr. Smith does not understand that the depreciation
2 adjustment performed by PSE is a *restating* adjustment not a *pro forma*
3 adjustment. PSE's depreciation adjustment *restates* the actual test period
4 depreciation expense as if the new rates had been in place as opposed to a *pro*
5 *forma* adjustment that would apply the new depreciation rates to the
6 September 30, 2016, end of period plant balances.

7 Mr. Smith's adjustment to common, which he did not discuss in testimony or
8 explain in his work papers, removes the test period depreciation expense
9 associated with only a portion of the common FERC Account 397,
10 Communication Equipment, on the basis that since that portion of the account is
11 fully amortized there will not be amortization (depreciation) expense in the rate
12 year, rather than leaving the test year amount unchanged. By doing so, he has
13 chosen to pro form one single FERC account (and only a portion of FERC
14 Account 397) to recognize that in 2018 those particular assets will no longer have
15 amortization expense. However, by doing this he has ignored the other portion of
16 the account where the test year included only a partial year of amortization
17 expense. This can be seen by reviewing the total amortization expense for
18 Common FERC Account 397 resulting from Mr. Smith's adjustment. His

⁵² Barnard, Exh. KJB-27.

1 adjustment only reflects 0.77 percent⁵³ for FERC Account 397 rather than the
2 6.67 percent proposed in the depreciation study.

3 Similar errors exist in the Electric and Gas pages as documented in Exhibit KJB-
4 28. If a complete pro forma adjustment were to be performed, the new
5 depreciation rates would be applied to the September 30, 2016, end of period
6 balances to reflect the full pro forma adjustment, rather than just a portion of
7 select FERC accounts. The resulting adjustment would certainly be higher than
8 that proposed by PSE. In short, Mr. Smith's pro forma adjustment is incomplete,
9 inappropriate, and should be rejected.

10 **C. Rate Case Expenses, Adjustment KJB-20.12**

11 **Q. Does your testimony respond to Commission Staff's adjustment of rate case
12 expenses?**

13 A. No. Ms. Susan Free discusses the difference in the position of PSE and
14 Commission Staff for this adjustment in her prefiled rebuttal testimony.

15 **D. Pension Plan Expense, Adjustment KJB-20.15**

16 **Q. Please discuss the positions of Public Counsel, ICNU, and NWIGU regarding
17 the pension adjustment.**

18 A. Mr. Ralph C. Smith, witness for Public Counsel, disagrees with PSE's long held
19 regulatory treatment of using a four-year average of cash contributions for setting

⁵³ Public Council Proposed Depreciation expense of \$491,610.51 divided by "Amortized"
FERC 397 plant value of \$63,796,964 = 0.77%

1 rates. He believes a more fully developed record exists in the current proceeding
2 to support his contention that a four-year average of PSE’s pension expense,
3 reported as required by the Financial Accounting Standards Board (“FASB”)
4 under Accounting Standard Codification 715 Compensation – Retirement
5 Benefits, formerly FAS 87, should be used.⁵⁴ Because other parties refer to
6 pension expense as FAS 87, I will do the same to avoid confusion.

7 Mr. Bradley G. Mullins, witness for ICNU and NWIGU, refers to the final Order
8 in PSE’s 2009 general rate case and incorrectly states that the Commission
9 required PSE to “use four years of expense, rather than four years of
10 contributions.”⁵⁵ Mr. Mullins proposes PSE use the *expected* 2017 pension
11 expense noted in PSE’s Form 10-K filing for calendar year 2016.

12 **Q. Does PSE agree that FAS 87 expense should be used as the basis for revenue**
13 **recovery?**

14 A. No. FAS 87 is a GAAP requirement established to provide guidance in reporting
15 net periodic pension costs for financial accounting reporting purposes.
16 Computations used to report FAS 87 are performed by actuaries using
17 assumptions regarding current and future demographics, life expectancy,
18 investment returns, levels of contributions or taxation, and payouts to

⁵⁴ Smith, Exh. RCS-1CT at 42:1 – 47:15.

⁵⁵ Both Mr. Smith and Mr. Mullins refer to *Wash. Utils. & Transp. Commission v. Puget Sound Energy*, Dockets UE-090704 & UG-090705, Order 11, (Apr. 2, 2010). Mr. Smith appropriately references both ¶¶ 79 and 80. However, Mr. Mullins omits reference to ¶ 80 wherein the Commission determines that there was not sufficient information in the record to move from contributions to expense. Accordingly, PSE has followed current precedence by requesting contributions despite what Mr. Mullins portrays on page 38 of his testimony.

1 beneficiaries, among other variables. Each of these measures is based on
2 estimates and are not actually known until a payout is made to the beneficiary,
3 which could be decades away. Most notably, the discount rate applied in
4 calculating pension interest expense and the expected return rate applied to the
5 plan assets are major components of the pension expense required to be reported
6 by companies under FAS 87, yet these rates have been a point of debate and
7 federal policy changes throughout the last three decades.

8 **Q. Does it make sense to accept FAS 87 as the best indicator of what PSE incurs**
9 **as pension costs?**

10 A. No. Very similar to PSE's regulatory treatment of ASC 815 Derivative and
11 Hedging (formerly FAS 133) transactions, expenses born out of adhering to a
12 unified accounting code for GAAP purposes is not necessarily representative of
13 costs that should be included for ratemaking purposes. Just as PSE eliminates the
14 impact of FAS 133⁵⁶ in rate setting, it should also continue to remove the
15 expenses associated with FAS 87 and base its pension expense on actual
16 contributions. Even Mr. Smith recognizes that FAS 87 does not dictate a
17 particular ratemaking treatment.⁵⁷

⁵⁶ FAS 133 requires companies to estimate the gain or loss that would occur at any given reporting period as if its outstanding derivatives were settled at that time. In other words, it requires companies to recognize the *unrealized* gains or losses associated with the reporting period even though the derivatives will not be settled until a future date, at which time their *realized* gains or losses will actually be booked.

⁵⁷ Smith, Exh. RCS-1T at 47:10.

1 **Q Can you provide an example of how FAS 87 expense is similar to FAS 133**
2 **from a ratemaking perspective?**

3 A. FAS 87 is similar to FAS 133 in that assumptions are made today for transactions
4 in the future; thus, until the event happens the true cost is not known. For
5 example, the FAS 87 calculation assumes that employees will be with PSE until
6 their retirement age of 65, and their salary on average will increase over time at a
7 rate of 4.5 percent. In addition, for FAS 87, the return on pension asset is set by
8 PSE based on what it believes the pension assets will earn. The discount rate used
9 in the calculation is based on a bond model in which PSE chooses the length of
10 bond and the rate to use. As a result, PSE is making a multitude of assumptions
11 regarding the pension plan that are not known until the future happens.

12 **Q. Why do you conclude that the cash contributions are a better indicator of**
13 **PSE's true pension costs?**

14 A. Although quarterly cash contributions are based upon PSE's review of the same
15 plan asset and Projected Benefit Obligation balances used to record FAS 87
16 pension expenses,⁵⁸ there is an important difference—cash paid by PSE goes
17 directly to the pension trust, and, once paid, it can never be taken back. The
18 contributions represent actual dollars coming out of PSE's cash account that are
19 paid into the Pension Trust where they will reside permanently in the trust until a
20 participant begins receiving his or her benefits. PSE believes the contribution

⁵⁸ Mr. Smith states that recognition of pension costs for ratemaking is typically based on some variant of FAS 87 costs. *See* Exhibit RCS-1CT at 57:1-2. The fact that the company's contributions are influenced by the FAS 87 analysis could fall under this "variant."

1 approach aligns closely with this Commission’s position on the relevance of cash
2 versus accrual accounting in rate setting. The recent authorization of PSE’s
3 property tax tracker ordered by the Commission in its Expedited Rate Filing
4 (“ERF”) in Dockets UE-130137 and UG-130138 is an example of the
5 Commission’s preference for known and measurable amounts. In that case, the
6 Commission agreed that rather than using accounting estimates of property tax
7 expense for rate setting purposes, it was more appropriate to set rates in a tracker
8 based on the known and measurable cash payments made by PSE.

9 **Q. Has a fully developed record been developed to support changing the**
10 **Commission’s historic treatment of PSE pension recovery?**

11 A. No. Mr. Smith provides a thorough overview of the categories of FAS 87 expense
12 and discusses, at length, the funding standards established by the Employee
13 Retirement Income Security Act (“ERISA”), the Pension Benefit Guaranty
14 Corporation, and the Pension Protection Act of 2006. However, none of this
15 supports why FAS 87 is a more appropriate metric to use for ratemaking purposes
16 than the Commission’s long standing practice of using normalized cash
17 contributions for ratemaking purposes.

18 Mr. Smith’s only support for making the change from normalized cash
19 contributions to FAS 87 is his belief that using the normalized contributions
20 “would significantly overstate the 2018 rate year pension expense,”⁵⁹ but only in

⁵⁹ Smith, Exh. RCS-1CT at 56:16-17.

1 relation to FAS 87 expense for which he provides no substantive evidence
2 proving it is the more appropriate measure for ratemaking. His support relies on
3 the 2016 actuarial study to reach his conclusion that *estimated future*
4 contributions will be less than the 2013 to 2016 four-year average of *actual*
5 contributions paid by PSE. He also points to the “fact” that his “recommended use
6 of a four-year average of net periodic pension cost is generally in line with the
7 Company’s projected cash contributions”⁶⁰ when he looks at the projected 2017
8 through 2025 period. None of these reasons support why FAS 87 expense is a
9 more appropriate metric to use for rate setting purposes other than it provides a
10 lower level of expense.⁶¹ Mr. Smith merely concludes that PSE’s projected
11 pension contributions are higher than its projected FAS 87 expense and, therefore,
12 moving to the FAS 87 expense should be accepted.

13 **Q. Does PSE agree with Mr. Smith’s statement that management has a wide**
14 **range of discretion as to how much to contribute each year?**

15 A. No. Perhaps one of the strongest arguments for continuing to use actual cash
16 contributions in setting rates is the existence of the natural checks and balances
17 occurring in today’s heavily scrutinized pension environment. PSE’s management
18 must continually maintain a balance to comply with strict guidelines set forth by
19 the Pension Benefit Guaranty Corporation to manage or avoid costly premiums,

⁶⁰ *Id.* at 59:3-4.

⁶¹ Although FAS 87 calculated expenses and cash contributions will over time eventually equal each other, it is improper ratemaking to switch between the two methodologies based on whichever method provides the lower number.

1 while justifying cash outlays to its board of directors. Mr. Smith's testimony
2 alludes to management's discretion in how much to contribute each year,⁶²
3 however, PSE is never incentivized to be either overfunded or underfunded in its
4 pension plan and Mr. Smith has not provided any documentation to suggest
5 otherwise. Therefore, using normalized actual cash contributions is not
6 unreasonable and does not incentivize PSE to over-contribute.

7 **Q. What guidelines does PSE follow to ensure the cash contributions are**
8 **appropriate?**

9 A. PSE determines its contribution levels each year in accordance with its own
10 Retirement Funding Guidelines, which adhere to ERISA, the Pension Benefit
11 Guaranty Corporation, and the Pension Protection Act of 2006 cited by
12 Mr. Smith. PSE's Retirement Funding Guidelines were approved by PSE's Board
13 of Directors in November 2009. I have included PSE's Response to ICNU Data
14 Request No. 58 as Exhibit KJB-29, which provides an example of the funding
15 guidelines calculation for 2016.

16 **Q. Why would PSE avoid being excessively *overfunded*?**

17 A. PSE does not have unlimited cash flow and carefully manages its pension
18 contributions based on its Retirement Funding Guidelines and applicable pension
19 enactments so that it can optimize its available cash to fund operating activities.
20 Once funds are contributed to the pension plan, they may not be removed.

⁶² Smith, Exh. RCS-1CT at 55:1-12.

1 Therefore, PSE has no incentive to excessively fund the pension plan, and
2 Mr. Smith has not provided any support to demonstrate otherwise.

3 **Q. How have PSE's pension obligations compared to PSE's plan assets?**

4 A. As provided in Exhibit TMH-6C, PSE's Projected Benefit Obligation balances
5 have been consistently higher than the plan assets for the past several years. In
6 fact, as indicated in PSE's Response to Commission Staff Data Request 134,
7 which is included as Exhibit KJB-30, PSE needed to make an additional
8 contribution in 2016 in order to meet the minimum funding to avoid unnecessary
9 premiums dictated by the Pension Benefit Guaranty Corporation for plans that are
10 underfunded.

11 **Q. If the Commission were to adopt Mr. Smith's recommendation and utilize**
12 **FAS 87 pension expense, are there accounts on the balance sheet that would**
13 **also need to be included in rate case proceedings?**

14 A. Yes. Because PSE is allowed the four-year average of contributions for rate
15 recovery, its balance sheet accounts associated with FAS 87 accounting are
16 currently included in non-operating investment for working capital purposes. If
17 the Commission were to adopt Mr. Smith's recommendation, then these balance
18 sheet accounts would need to be moved from non-operating investment to
19 working capital.

1 **Q. Why does Mr. Mullins refer to Docket UE-140762 in claiming that the**
2 **Commission has been moving away from historical contributions?**⁶³

3 A. Mr. Mullins provides no support for why Docket UE-140762 involving
4 PacifiCorp is relevant in determining whether FAS 87 or cash contributions is the
5 appropriate ratemaking treatment of PSE's pension expense. The Public Counsel
6 witness to whom Mr. Mullins refers addressed the issue of whether the pre- or
7 post-test year pension actuarial report should be used for the FAS 87 expense to
8 be included in the revenue requirement, not whether cash contributions or FAS 87
9 expense is appropriate for ratemaking purposes. In fact, Mr. Mullins' testimony
10 documents that the use of average contributions over a four year period has been
11 in place for PSE "at least as far back as Docket UE-920433."⁶⁴

12 In sum, Mr. Mullins has incorrectly interpreted the Commission's order in PSE's
13 2009 general rate case as changing the approved methodology from average
14 contributions to FAS 87 expense and questions the use of the four-year average in
15 the 2011 general rate case, which was uncontested in that case. Mr. Mullins has
16 provided no support for a change from the current methodology and, therefore, his
17 pension expense adjustment should be rejected.

⁶³ Mullins, Exh. BGM-1CTr at 38:7-11.

⁶⁴ Mullins, Exh. BGM-1CT at 37:15-16.

1 **Q. Mr. Mullins advocates using an estimated amount of FAS 87 expense for a**
2 **single year, for setting rates.⁶⁵ Does PSE agree with this approach?**

3 A. No. PSE's 2017 FAS 87 expense is even more unmeasurable than the four-year
4 average that Public Counsel proposes. Furthermore, use of a single year does not
5 adequately recognize the varying nature of pension history.

6 **Q. Please summarize PSE's recommendation.**

7 A. The Commission should approve PSE's proposed pension adjustment. The current
8 regulatory treatment for PSE's pension expenses, using the four-year average of
9 cash contributions, has been effective, straightforward, and aligns recovery with
10 the actual cash contributions that are invested in the pension trust to ensure
11 payment of the retirement benefits earned by PSE employees working on behalf
12 of customers. The cash contributions are known and measurable and made under
13 adherence to applicable enactments and PSE policy, as opposed to FAS 87
14 expense, which is based on complex actuarial estimates.

15 Consistency is important. Changing methods from a cash basis to an accrual basis
16 may cause periods of time that customers may pay more or less than they should
17 related to these benefits. The consistent use of a cash basis methodology
18 (i.e., cash contributions) ensures that customers only pay for costs that have been
19 incurred by PSE due to averaging the previous four years contributions of the
20 pension plan.

⁶⁵ *Id.* at 39:1-7.

1 **E. Environmental Remediation, Adjustment KJB-20.19**

2 **Q. Does your testimony address the environmental remediation adjustment,**
3 **Adjustment KJB-20.19?**

4 A. No. Ms. Susan Free discusses the difference in the position of PSE and other
5 parties for the environmental remediation adjustment, Adjustment KJB-20.19.⁶⁶

6 **F. Working Capital, Adjustment KJB-20.23**

7 **Q. Does your testimony address the working capital adjustment, Adjustment**
8 **KJB-20.23?**

9 A. No. Ms. Susan Free discusses the difference in the position of PSE, and
10 Commission Staff for the working capital adjustment, Adjustment KJB-20.23.⁶⁷

11 **G. Power Costs and Production O&M, Adjustment KJB-21.01**

12 **Q. What changes have been made to the power cost adjustment since the**
13 **supplemental filing?**

14 A. The Prefiled Rebuttal Testimony of Paul K. Wetherbee, Exhibit PKW-15CT,
15 describes the differences between PSE's power costs and the power costs
16 proposed by Commission Staff and ICNU witnesses. The Prefiled Rebuttal
17 Testimony of Ronald J. Roberts, Exhibit RJR-30T, addresses (i) PSE's concession
18 of Commission Staff's proposal to reduce PSE's rate year costs for its licensing

⁶⁶ Free, Exh. SEF-12T.

⁶⁷ Free, Exh. SEF-12T.

1 activities relating to Snoqualmie and Baker Hydroelectric projects to reflect test
2 year levels and (ii) updates for major maintenance on Colstrip Units 1 and 2.

3 **Q. Are there any updates to the Open Access Transmission Tariff (“OATT”)**
4 **revenues since the supplemental filing?**

5 A. Yes. As mentioned in my prefiled direct testimony, the current OATT formula
6 rates were finalized and became effective June 1, 2017, and the increased revenue
7 from the higher rates has been reflected in this rebuttal filing.

8 **Q. Are there any other issues you need to discuss related to power costs?**

9 A. Yes. As a result of PSE’s acceptance of Commission Staff witness Jing Liu’s
10 recommendation to remove the fixed cost production factor,⁶⁸ as I discuss later,
11 adjustments which are defined as fixed production costs⁶⁹ and that are being
12 requested for inclusion in the decoupling mechanism no longer have the fixed
13 production factor applied. This results in the costs included in the revenue
14 requirement being 2.535 percent higher than if the production factor had been
15 applied. This change is being made as these costs would no longer be subject to
16 growth in customers between the test year and the rate year.

17 Overall, including the changes for (i) removing the fixed production factor,
18 (ii) the update for increased OATT revenues, and (iii) the changes discussed by
19 Mr. Paul Wetherbee and Mr. Roberts in their rebuttal testimonies, the impact on

⁶⁸ See generally Liu, Exh. JL-1CT at 46:1 – 56:12.

⁶⁹ Production O&M, 557 Other Power Supply Expenses and 456 OATT Revenues.

1 net operating income for this adjustment is now a decrease of \$682,861 compared
2 to the \$14,772,510 decrease included in the supplemental filing.

3 **H. Storm, Adjustment KJB-21.05**

4 **Q. Please explain the differences between PSE and the parties for this**
5 **adjustment.**

6 A. Commission Staff witness Schooley proposes that the Commission rescind the
7 storm deferral mechanism, and he prepares his storm damage adjustment
8 retroactively, assuming that his methodology was approved by the Commission in
9 the 2011 general rate case.⁷⁰ Kroger Witness Higgins recommends that the
10 remaining costs associated with the 2006 storm event, frequently referred to as the
11 “Hanukkah Eve” storm, be moved to a separate rider and recommends that the
12 post-test year qualifying events only be included in rates if they are above the
13 \$10.6 million included in “normal rates.”⁷¹ Public Counsel witness Smith
14 proposes that the 2012 storm event, frequently referred to as “Snowmageddon”
15 event, be amortized over a ten-year period similar to the Hanukkah Eve storm.⁷²

16 **Q. What is your overall response to the modifications proposed by Commission**
17 **Staff witness Schooley to the storm deferral mechanism?**

18 A. Commission Staff is utilizing recycled arguments that the Commission has
19 rejected, as recently as PSE’s last general rate case, to eliminate the storm deferral

⁷⁰ Schooley, Exh. TES-1T at 21:14 – 22:8.

⁷¹ Higgins, Exh. KCH-1T at 5:19 – 6:2.

⁷² Smith, Exh. RCS-1CT at 36:3-13.

1 mechanism that has worked well and benefited both customers and PSE for more
2 than a decade. Not only does Commission Staff's proposal eliminate the existing
3 storm deferral mechanism on a going forward basis, the adjustment as proposed
4 by Mr. Schooley attempts to retroactively implement his proposal by disallowing
5 recovery of the more than \$60 million of previously deferred storm costs that
6 were properly deferred under the existing mechanism. The Commission should
7 reject Commission Staff's proposal, allow the storm deferral mechanism to
8 continue, and approve the proposed amortization of the costs associated with the
9 2012 through 2017 qualifying events as reflected in Adjustment KJB-21.05.

10 **Q. Can you provide a brief history of PSE's storm deferral mechanism?**

11 A. Prior to Docket UE-921262 storm damage was recovered using an accounting
12 reserve in a manner similar to insurance. All storm damage was deferred by
13 charging a reserve and the amount allowed in rates was credited to that reserve
14 and charged to storm damage expense. In Docket UE-921262, Commission
15 Staff⁷³ proposed normalizing storm damage costs over a six-year period, and that
16 extraordinary property damage be amortized over a six-year period. In that
17 docket, Commission Staff proposed to define "catastrophic event" as one
18 affecting 25 percent or more of PSE's customers, occurring infrequently, and
19 affecting a wide geographic area. Mr. Schooley's proposal in that case was
20 approved by the Commission and that definition of catastrophic storm was used
21 until 2004. In Docket UE-040641, in response to PSE's proposal to define a

⁷³ Docket UE-921262, Schooley, Exh. TES-1T.

1 qualifying event as greater than \$2 million, Commission Staff witnesses
2 Mr. Douglas E. Kilpatrick and Mr. James M. Russell proposed the current
3 methodology of using the Institute of Electrical and Electronic Engineers (IEEE)
4 standard 1366-2003 using the 2.5 Beta Methodology, modified to shorten the
5 duration of a sustained interruption from five minutes to one minute (“IEEE
6 Standard” or “2.5 Beta Method”) to define a “major event” and including a
7 threshold of “normal” storm costs to replace the “catastrophic event” standard of
8 25% of customers without power previously approved by the Commission. PSE
9 did not object to using the IEEE standard as a trigger for deferring storm damage,
10 and the Commission approved the current definition for qualifying storms using
11 the IEEE Standard. This definition and benefits associated with using the IEEE
12 Standard is explained in more detail in the Prefiled Rebuttal Testimony of
13 Catherine A. Koch, Exh. CAK-4T.

14 **Q. Are there other types of storm events for which PSE incurs costs other than**
15 **those meeting the IEEE Standard for a qualifying event?**

16 A. Yes. There are costs incurred for other storm events that do not meet the IEEE
17 Standard and those costs are referred to as normal or “non-qualifying” storm
18 costs.

19 **Q. Is PSE allowed to defer any “normal” storm costs?**

20 A. No. PSE is not allowed to defer any costs for storms that do not meet the IEEE
21 major event standard approved in Docket UE-040641. These normal storm costs
22 are part of the normalization calculation which uses a six-year average. As

1 discussed by Mr. Kilpatrick in Docket UE-040641, the IEEE major event day
2 concept is used to establish a threshold value for a company's normal daily
3 reliability as expressed in a daily value for SAIDI:

4 Any days with a daily SAIDI value greater than this threshold are
5 considered as those days where the electrical system experienced
6 above-normal stresses, such as during severe weather. The
7 system's performance during these major event days is evaluated
8 separately from day-to-day operation so that measurement of the
9 underlying reliability of the electric system is not overshadowed by
10 these significant events.⁷⁴

11 **Q. What storm costs are allowed to be deferred?**

12 A. PSE is only allowed to defer costs associated with qualifying IEEE storm events
13 that exceed an annual dollar threshold. This annual threshold is determined and
14 approved in a general rate case. The annual threshold was based on the six-year
15 average normal storm expense and is currently set at \$8 million. Only when IEEE
16 qualifying storm expenses exceed the \$8 million threshold are they allowed to be
17 deferred. The Prefiled Rebuttal Testimony of Catherine A. Koch, Exhibit CAK-
18 4T, describes other costs that are related to IEEE-qualifying storms that are not
19 deferred.

20 **Q. Can you please summarize PSE's cost treatment and deferral capabilities**
21 **under its storm mechanism?**

22 A. Yes. The following chart provides a simple snapshot of PSE's existing storm
23 deferral mechanism.

⁷⁴ Docket UE-040640, Kilpatrick, Exh. DEK-1T at 8:3-6.

1

Table 3. Types of Storm Expense and Treatment

Type of Expense	Mechanism		
	Normalize	Defer & Amortize	
	6 Years	4 Year ^(*)	10 Year ^(*)
Non-Qualifying	X		
IEEE qualifying below threshold	X		
IEEE qualifying above threshold		X	X
<p>(*) The length of the amortization period has varied over time since UE-040641 when the IEEE qualifying provisions were adopted as the definition of a catastrophic storm. The length of the amortization period has been agreed to during the course of subsequent proceedings based on intervenor proposals made primarily to lessen the rate impact of storm deferrals.</p>			

2

3

Q. Does Mr. Schooley propose a new definition for qualifying events?

4

A. No. In Commission Staff’s Response to PSE Data Request No. 02, which I have included as Exhibit KJB-31, Mr. Schooley recommends the Commission rescind the current mechanism in its entirety and instead proposes that PSE file a deferred accounting petition to request deferral should an event reach the magnitude of the 2012 Snowmageddon and 2006 Hanukkah Eve storms. Additionally, his proposal retroactively applies the rescission of the deferral mechanism back to 2011 by rejecting the amortization of the deferrals associated with costs for qualifying

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1 events that have been deferred since the last case as well as removing the deferrals
2 from the working capital calculation.⁷⁵

3 **Q. On what basis does Commission Staff exclude the amortization of the**
4 **deferred storm costs?**

5 A. Mr. Schooley’s entire premise for “un-deferring” the 2012 through 2017⁷⁶ events,
6 except for the Snowmageddon storm, is that, in his view, these events were not
7 truly “catastrophic” events.⁷⁷ He believes that the IEEE threshold that the
8 Commission authorized was too easily met and that the \$8 million threshold
9 before deferrals could begin was too low of a hurdle.⁷⁸ In essence, he is asking the
10 Commission to pretend that it accepted Commission Staff’s proposal in the 2011
11 general rate case by rejecting the amortization of the deferred storm costs
12 reflected on lines 24 through 26b of Exhibit KJB-21.05.

13 **Q. Mr. Schooley claims that he has properly accommodated the costs he is “un-**
14 **deferring” by including them in the six-year average. Does PSE agree?**

15 A. No. Commission Staff implies that the deferred costs do not need to be recovered
16 because they are included in the calculation of the six-year average that would be
17 used to “set a reasonable level of ongoing cost recovery.”⁷⁹ However

⁷⁵ Schooley, Exh. TES-1T at 21:18 – 22:19.

⁷⁶ In supplemental testimony, Adjustment KJB-21.05 was updated to include deferred storm costs associated with 2017 qualifying event costs through February 28, 2017.

⁷⁷ Schooley, Exh. TES-1T at 19:2-10.

⁷⁸ *Id.* at 19:4-6.

⁷⁹ *Id.* at 21:17-21.

1 Mr. Schooley’s adjustment to the six-year average merely addresses the average
2 level of storm costs to be included in the rate year for inclusion in base rates,
3 which would be necessary if the current storm deferral mechanism was to be
4 eliminated on a going-forward basis. His adjustment has done nothing to address
5 the costs that were deferred over the past six years consistent with PSE’s
6 approved storm deferral mechanism—the mechanism that the Commission
7 considered and approved continuation of in PSE’s last general rate case.
8 Commission Staff is requesting that the Commission retroactively rescind its
9 decision from the 2011 case by requiring PSE to “un-defer” those expenses,
10 which would result in a write-off of more than \$60 million of prudently deferred
11 qualifying event costs.

12 **Q. Does PSE believe adoption of Commission Staff’s adjustment would be**
13 **equivalent to retroactive ratemaking?**

14 A. Yes. As mentioned earlier, Commission Staff proposed a similar elimination of
15 the storm deferral mechanism in PSE’s last general rate case, which the
16 Commission rejected. In rejecting Commission Staff’s proposal, the Commission
17 authorized PSE to “retain the current Commission-approved mechanism for storm
18 damage recovery.”⁸⁰ However, Mr. Schooley’s testimony refers to “un-deferring”
19 the costs associated with qualifying storm costs that occurred since PSE’s last
20 general rate case. The only reason for “un-deferring” these costs would be if they
21 were found imprudent or if PSE had inappropriately deferred them. That is clearly

⁸⁰ See Dockets UE-1111048, *et al.*, Order 08, 104 ¶ 299.

1 not the case. Commission Staff's Response to PSE Data Request No. 09⁸¹ admits
2 that Mr. Schooley neither questions the prudence of nor asserts that that PSE
3 inappropriately deferred these storm costs. His testimony, which falsely indicates
4 that the cost recovery of these deferred storms has been addressed by their
5 inclusion in his calculated six-year average, seems disingenuous. This is
6 especially evident when considering that he makes a restating adjustment to the
7 test period Investor Supplied Working Capital to recognize the impact of the
8 write-off should the Commission accept his proposal and not allow amortization
9 of the deferred storm costs as of the end of the test year.

10 **Q. Are there benefits to customers from maintaining the current mechanism,**
11 **which Mr. Schooley ignores?**

12 A. Yes, there are several. First, with the existing mechanism, during a storm event,
13 PSE can focus on restoring power for its customers rather than worrying about
14 filing an accounting petition to request deferral of the associated costs. Without a
15 storm deferral mechanism in place, PSE cannot defer any costs until an
16 accounting petition is filed and any costs incurred before the filing of the
17 accounting petition cannot be deferred and amortized. Under the existing
18 mechanism, PSE has 30 days to notify the Commission of a qualifying event and
19 that deferral of storm costs may occur. Second, Mr. Schooley's approach raises
20 the six-year average, increasing the costs to customers for events which may not
21 happen.

⁸¹ Barnard, Exh. KJB-32.

1 Under the storm deferral mechanism customers only pay for the qualifying events
2 that actually occur above the \$8 million annual threshold allowing for the range of
3 “normal” costs included in the six-year average to be relatively consistent.

4 Exhibit KJB-33 demonstrates this difference by comparing the six-year average
5 normal storm costs reflected in Adjustment KJB-21.05 to that reflected on page
6 35 of Ms. Cheesman’s Exhibit MCC-2.⁸² In Commission Staff’s adjustment, the
7 amount of normal storm damage expense that would be built into rates in this
8 proceeding would be approximately \$18.8 million, which is nearly double the
9 \$10.6 million included in the level of normal storms calculated in PSE’s
10 adjustment.

11 Additionally, under Commission Staff’s proposal, the annual “normal” storm
12 costs vary from a low of \$6.7 million for the twelve months ending September 30,
13 2013, to a high of \$36.8 million for the twelve months ending September 30,
14 2015—a variance of \$30 million. This compares to PSE’s adjustment where the
15 variance between the high and low is only a \$7 million variance (\$6.7 million to a
16 high of \$13.1 million). Under Commission Staff’s proposal with “normal storm
17 costs” the \$18.8 million would have been higher than necessary in four out of six
18 years *had* it been in place. This compares to only two years out of six under PSE’s
19 six-year average calculation of \$10.6 million. *See* Adjustment KJB-21.05. If only
20 storms the magnitude of Snowmageddon or Hanukkah Eve could be considered
21 for deferral, this range of “normal storm costs” could be even wider in the future

⁸² Ms. Cheesman reflects the six year normal storm average as recommended by Mr. Schooley on page 2 of his Exhibit TES-3.

1 and could have a substantial impact on the range of costs that are treated as
2 normal and on the six-year average over time.

3 **Q. How does PSE address Mr. Schooley’s concern that there are ‘too many’**
4 **qualifying storms and they are not truly ‘catastrophic’?**

5 A. The IEEE Standard adopted for purposes of the storm mechanism was defined as
6 “a major event” and that is why there is an \$8 million annual threshold that must
7 be met before costs associated with qualifying events can be deferred. For years
8 where there were qualifying storm deferrals, PSE will have always exceeded the
9 six-year average storm cost that had been established in rates. For example, the
10 six-year average storm costs established in the 2011 general rate case was
11 \$8.8 million. As can be seen in Adjustment KJB-21.05, in 2012, 2014 and 2015,
12 the years where there are outstanding deferrals for qualifying storms, the normal
13 storm costs PSE incurred and expensed exceeded the \$8.8 million currently
14 established in rates.

15 **Q. Are the number of qualifying events significantly different from the levels**
16 **seen in 2006 through 2010, the period reviewed in PSE’s last general rate**
17 **case?**

18 A. No. During the 2006 through 2010 time period, there were 32 qualifying events,
19 11 qualifying events in 2006 alone.⁸³ This compares to the 23 qualifying events
20 during the 2011 through 2016 period to which Mr. Schooley refers. None of the

⁸³ Work paper filed in support of Exhibit TES-2, tab “qualifying event” included as Exhibit KJB-34.

1 years had as many events as 2006; however, both calendar 2014 and 2015 had
2 seven qualifying events.

3 **Q. Mr. Schooley states that the current mechanism is biased toward PSE,⁸⁴ does**
4 **PSE agree?**

5 A. No. Mr. Schooley makes this statement but provides no concrete evidence to
6 support his claim that the current mechanism is biased and unfair to customers.
7 The existing mechanism requires two thresholds to be met: (i) the IEEE standard
8 of “major event” must be met; and (ii) the first \$8 million in annual qualifying
9 event costs must be absorbed by PSE. Only then is deferral of qualifying storm
10 costs possible. Together those two criteria ensure that the only years where storm
11 costs are actually deferred are those years when PSE’s actual storm costs will
12 exceed the amount built into rates.

13 **Q. Does PSE agree with Commission Staff that there are no substantive losses to**
14 **changing the mechanism?⁸⁵**

15 A. No. Commission Staff’s adjustment as proposed will result in PSE writing off
16 more than \$60 million of prudently incurred and deferred qualifying storm costs,
17 which represents a \$39.6 million decrease in after tax net income (\$60.9 million ×
18 (1 – 0.35)). Considering that in her testimony, Ms. Cheesman views a change of

⁸⁴ Schooley, Exh. TES-1T at 23:16.

⁸⁵ *Id.* at 23:21-22.

1 one basis point of earnings to be material,⁸⁶ a decrease of nearly 75 basis points⁸⁷
2 is obviously substantial.

3 Commission Staff contends that with decoupling there is stable recovery of storm
4 costs because the six-year average is part of the allowed revenue per customer and
5 therefore PSE will recover its costs.⁸⁸ Unfortunately, Commission Staff has
6 missed the point that, under Commission Staff's proposal (i) the only costs that
7 will be recovered because of decoupling is the average costs and (ii) there is
8 considerably more variability in the definition of "normal" costs, which harms
9 customers by setting the average higher than it would otherwise need to be if the
10 mechanism was left unchanged.

11 **Q. Has any other party proposed a change to the storm deferral mechanism?**

12 A. No. Only Commission Staff has proposed changes to the storm deferral
13 mechanism.

14 **Q. If the Commission were to accept Mr. Schooley's proposal, does PSE believe**
15 **his adjustment has been calculated correctly?**

16 A. Not entirely. PSE can agree with Mr. Schooley's calculation of the six-year
17 average as \$18.8 million, which is consistent with the figure reflected on line 11
18 of Exhibit MCC-2 Adjustment 13.09. However, any modification to the storm

⁸⁶ Cheesman, Exh. MCC-1T at 24:1-5.

⁸⁷ $\$39.6 \text{ million} \div \$530,000 = 74.7 \text{ basis points}$. \$530,000 is found in Response Testimony of Ms. Melissa C. Cheesman, Exhibit MCC-1T at 24:4.

⁸⁸ Schooley, Exh. TES-1T at 24:2-7.

1 mechanism must be done on a prospective basis, and the deferred storm costs that
2 were booked would need to be amortized as reflected in PSE's adjustment. Any
3 change that does not address the outstanding deferrals will result in a significant
4 retroactive write-off of prudently incurred and deferred storm cost and is certainly
5 unfair to PSE.

6 **Q. Is Mr. Schooley's adjustment to investor supplied working capital necessary**
7 **if the storm mechanism is changed on a going forward basis?**

8 A. No. As discussed earlier, the adjustment to investor supplied working capital is
9 directly related to Mr. Schooley's proposal to "un-defer" previously recorded
10 deferred storm costs balances. Additionally, his adjustment removes the
11 September 30, 2016 end of period⁸⁹ balance for the storms that he would "un-
12 defer," decreasing rather than utilizing the test year AMA balances that were
13 included in the working capital calculation.

14 **Q. Are there any other elements to Commission Staff's proposed changes to the**
15 **storm mechanism that you would like to address?**

16 A. Yes. First, Commission Staff proposes that catastrophic storm deferrals begin
17 amortizing in the month when the repair work is completed, claiming that the
18 deferred costs are similar to plant costs which begin depreciating once placed in

⁸⁹ Mr. Schooley's adjustment incorrectly utilized end of period deferred storm costs rather than the AMA balances that are included in the working capital calculation when calculating his adjustment. Although appropriately not included in his working capital adjustment, any post-test year qualified storm deferrals would also need to be written off if the Commission were to accept Commission Staff's proposal, totaling the \$60 million referenced earlier in my testimony.

1 service.⁹⁰ Commission Staff's proposal would result in the amortization of the
2 catastrophic storm costs before they were included in rates, which would typically
3 occur in the next general rate case or possibly an expedited rate filing. His
4 assumption that deferred storm costs are the same as the capitalized plant which is
5 placed in service and begins depreciation is simply not true because the plant has
6 a far longer life than the amortizations associated with storm costs. Storm costs
7 have typically been amortized over a four-year period, and the longest
8 amortization period used for storm costs has been the ten-year amortization used
9 for the Hanukah Eve storm compared to the depreciation lives of 30 to 50 years
10 for distribution and transmission assets. Thus, under Mr. Schooley's proposal,
11 PSE would not be able to recover much of the costs it incurs especially for the
12 limited number of storms that would be catastrophic storms under his proposal,
13 since they would be partially or fully amortized before they could be recovered in
14 rates.

15 Additionally, from an administrative perspective, Commission Staff's proposal is
16 not realistic. PSE would be required to file an accounting petition to request
17 deferred accounting for the costs associated with the storm event, which should be
18 first approved before an amortization would begin.

19 The final element to be addressed is Mr. Schooley's proposal that the six-year
20 average storm normalization adjustment be included in the Commission Basis

⁹⁰ Schooley, Exh. TES-1T at 25:2-8.

1 Report or in the expedited rate filing process.⁹¹ PSE can agree that including the
2 six-year average in an expedited rate filing or the Commission Basis Report
3 would be appropriate, provided that this adjustment not be included for purposes
4 of the earnings test.

5 **Q. Why should the storm normalizing adjustment not be included for earnings**
6 **sharing purposes?**

7 A. As addressed in the Prefiled Rebuttal Testimony of Daniel A. Doyle, Exhibit
8 DAD-7T, the inclusion of normalization adjustments in the earnings test creates
9 phantom earnings or reduces actual earnings when used in the earnings sharing
10 calculation. By removing actual period expenses and replacing them with an
11 average, the actual impact on PSE's operations for the year is removed. The
12 inclusion of normalization adjustments for ratemaking and Commission Basis
13 Reporting is completely reasonable as both instances are intended for assessing
14 PSE's income under normal conditions. However, the earnings sharing test is
15 intended to review whether PSE earned above its authorized rate of return and
16 whether there are excess earnings to share with customers. Therefore, it is not
17 appropriate to include normalization adjustments for earnings sharing purposes
18 where these adjustments are actually distorting the earnings of PSE for the
19 reporting period by pretending that normal conditions occurred.

⁹¹ *Id.* at 24:17-21.

1 Exhibit KJB-35, provides a comparison of the impacts on reported earnings if the
2 storm normalization adjustment had been included in the calendar year 2015
3 earnings sharing calculation under both the existing storm mechanism and the
4 impacts under Commission Staff's proposal where the mechanism would be
5 retroactively eliminated. Line 1 of Exhibit KJB-35 shows that including the six-
6 year average storm normalization rather than the actual expenses incurred during
7 the reporting period would have created an additional \$1,024,621 or two basis
8 points of "earnings" that PSE actually did not earn during that period. The exhibit
9 also provides comparisons assuming that the highest level (line 2) and lowest
10 level (line 3) of storm expenses had been incurred during the test period to
11 demonstrate the range of volatility in calculated earnings that would occur if the
12 normalization adjustment were to be included for earnings sharing purposes. The
13 range of volatility is \$4.7 million or 9 basis points.

14 The disparity would be even greater if the Commission were to make
15 modifications to the existing storm deferral mechanism proposed by Commission
16 Staff. Lines 4 and 5 reflect the 2015 normalization adjustment, under Commission
17 Staff's proposed approach in which no storms would have been deferred in
18 calendar 2015, resulting in \$35 million of actual storm expenses during that
19 period. Through the normalization process, the actual expenses would be replaced
20 with the six-year average, eliminating approximately \$16 million of *actual*
21 expenses incurred by PSE during the reporting period increasing the reported net
22 operating income by \$10.4 million, or a 20 basis point difference. The same
23 would be true if actual storm expenses had only been \$4.4 million, the lowest year

1 in the six-year average. In a year when PSE would have significantly less actual
2 storm expenses, PSE would replace the actual cost of \$4.4 million, with additional
3 expenses of \$14.8 million through the normalization process eliminating
4 \$9.6 million of earnings, or 18 basis points, that would have otherwise been
5 shared with customers. Commission Staff's proposal adds \$20 million of added
6 after tax volatility to PSE's earnings that Commission Staff proposes be ignored
7 in the calculation of the earnings test.

8 Regardless of whether the Commission chooses to modify the storm deferral
9 mechanism, the Commission should reject Commission Staff's proposal to
10 include the storm normalization adjustment for earnings sharing purposes.

11 **Q. Please explain the modifications to PSE's storm normalization adjustment**
12 **proposed by Kroger witness, Mr. Higgins?**

13 A. Mr. Higgins recommends that the remaining costs from the Hanukkah Eve storm
14 be moved to a separate rider and recommends that the post-test year events only
15 be included in rates if they are above the \$10.6 million included in "normal
16 rates."⁹²

17 **Q. Does PSE agree with Mr. Higgins' proposal regarding a separate tracker for**
18 **the remaining Hanukkah Eve balance?**

19 A. No. It is unnecessary to move the remaining Hanukkah Eve storm deferral to a
20 separate tracker. As demonstrated by the excess amortization that was tracked

⁹² Higgins, Exh. KCH-1T at 5:20 – 6:2.

1 with the 2010 events, PSE would continue to recognize amortization expense
2 against the Hanukkah Eve storm, which would result in a negative balance that
3 could be used to offset future events. In the alternative, the excess amortization
4 from the 2010 events could be used to offset the remaining Hanukkah Eve
5 balance rather than offsetting the 2014 through 2016 events, as PSE has proposed
6 in its initial filing. This would be a far simpler approach than creating a separate
7 tracker for the remaining Hanukkah Eve balance.

8 **Q. Mr. Higgins also proposes that the post-test year amounts only be allowed for**
9 **amortization if they are above the six-year average being established in this**
10 **case (\$10.6 million).⁹³ Does PSE agree with his proposal?**

11 A. No. Mr. Higgins fails to recognize that for those costs to have been deferred, the
12 total annual qualifying events had to exceed the \$8 million threshold, the existing
13 six-year average storm costs from the last case which represents the amount
14 currently established in base rates. The \$10.6 million will not be incorporated in
15 base rates until the completion of this case. The qualifying storm events were
16 appropriately deferred pursuant to the standard set in PSE's 2011 general rate case
17 and therefore his proposal for treatment of these deferred amounts should be
18 rejected.

⁹³ *Id.* at 6:3-9.

1 **Q. Should the \$8 million threshold for qualifying events be increased at the**
2 **conclusion of this case?**

3 A. Yes. Assuming the definition of qualifying event remains unchanged from the
4 current 2.5 Beta Method, it would be appropriate to increase the threshold to
5 \$10 million to be consistent with the level of average storm costs established in
6 this proceeding. The new threshold should commence for storm deferrals
7 beginning in calendar 2018, shortly after the conclusion of this case.

8 **Q. Public Counsel witness Smith proposes a longer amortization of 2012 storm**
9 **costs. Does PSE agree with his proposal?⁹⁴**

10 A. No. Further extending the amortization period is unnecessary. The six-year
11 amortization period is reasonable considering the level of deferred expense
12 associated with that storm event is approximately 60% of the level of the
13 Hanukkah Eve storm that was amortized over ten years.

14 **Q. Please summarize PSE's recommendation regarding the storm recovery**
15 **mechanism and storm damage adjustment?**

16 A. The summary of my recommendations is as follows:

17 1) Approve continuation of the existing storm recovery
18 mechanism retaining the 2.5 Beta Method for qualifying
19 events, but increasing the annual threshold for qualifying
20 events from \$8 million to \$10 million beginning in 2018;

⁹⁴ Smith, Exh. RCS-1CT at 36:5-7.

- 1 2) Reject Commission Staff’s proposed storm damage
2 adjustment, including the adjustment to investor supplied
3 working capital;
- 4 3) Reject the modifications to storm deferral amortizations
5 proposed by both Mr. Higgins and Mr. Smith; and
- 6 4) Approve PSE’s storm damage adjustment as presented in
7 Adjustment KJB-21.05, which decreases net operating
8 income by \$8,389,018 and remains unchanged from the
9 supplemental filing.

10 **I. Energy Imbalance Market, Adjustment KJB-21.08**

11 **Q. Please describe Commission Staff’s proposal with respect to the EIM**
12 **adjustment.**

13 A. Commission Staff witness Frankiewich does not contest the calculations of PSE’s
14 EIM Adjustment or its prudence; however, he proposes that all costs associated
15 with the EIM should not be included in either general rates or the PCA baseline
16 rate, but should be included as a line item in the PCA so that benefits would be
17 reflected in the PCA sharing bands.⁹⁵

18 **Q. Do you have concerns with Mr. Frankiewich’s proposal?**

19 A. Yes. Commission Staff’s proposal is inconsistent with the PCA settlement
20 recently approved by the Commission.⁹⁶ As discussed in the Prefiled Rebuttal
21 Testimony of Mr. Paul K. Wetherbee, Exhibit PKW-15T, Commission Staff is
22 proposing to modify the updated PCA mechanism that was just implemented

⁹⁵ Frankiewich, Exh. KAF-1T at 13:15 – 14:15.

⁹⁶ See *Wash. Utils. & Transp. Comm’n v. Puget Sound Energy*, Docket UE-130617, *et al.*, Order 11 at ¶ 18 (Aug. 7, 2015).

1 eight months ago. As part of the PCA settlement in Docket UE-130617, the
2 parties agreed to a five-year moratorium, which prohibited parties from
3 advocating for changes to the PCA mechanism during that time period.⁹⁷
4 Additionally, the settlement removed fixed costs from the PCA mechanism—a
5 change for which Commission Staff had advocated. Now, less than a year after
6 the PCA changes were implemented, Mr. Frankiewicz proposes to change the
7 PCA mechanism by including fixed costs in the PCA associated with PSE joining
8 the EIM.⁹⁸ Mr. Frankiewicz’s proposal seems to stem completely from his
9 misunderstanding of the relationship between general rates and the baseline rate
10 used in the PCA mechanism.

11 **Q. Does Mr. Frankiewicz challenge either the prudence of joining the EIM or**
12 **the capital costs and O&M included in PSE’s proposed adjustment?**

13 A. No. In fact, Mr. Frankiewicz makes it clear that he does not challenge the
14 prudence of joining the EIM,⁹⁹ the prudence of the costs,¹⁰⁰ or the calculation of
15 the adjustments.¹⁰¹

⁹⁷ See *id.* at ¶ 20.

⁹⁸ Frankiewicz, Exh. KAF-1T at 13:17 – 14:15.

⁹⁹ *Id.* at 6:4.

¹⁰⁰ *Id.* at 7:7-8.

¹⁰¹ *Id.* at 14:10-12.

1 **Q. How do you respond to Mr. Frankiewich's assessment that PSE's proposal**
2 **puts a burden on ratepayers to cover capital costs?**

3 A. Mr. Frankiewich claims that the pro forma adjustment places the burden of
4 covering capital costs directly through general rates yet the EIM benefits will
5 mostly accrue to PSE through the PCA mechanism.¹⁰² Mr. Frankiewich's
6 assessment quite frankly does not make sense since the overall impact on general
7 rates is zero. The increased revenue requirement of \$8.47 million associated with
8 the incremental capital and O&M costs has been completely offset by the direct
9 reduction to power costs for the estimated benefits of \$8.47 million, included in
10 Adjustment KJB-21.01.¹⁰³ The costs and benefits entirely offset within the
11 revenue requirement model; therefore, the impact on general rates in this
12 proceeding is zero.

13 The Commission should reject Mr. Frankiewich's proposal and approve the EIM
14 adjustment as reflected in Adjustment KJB-21.08 and without modification to the
15 PCA mechanism.

¹⁰² *Id.* at 11:13-16.

¹⁰³ *See* Barnard, Exh. KJB-1T at 49:19 – 50:4.

1 **J. White River, Adjustment KJB-21.11**

2 **Q. What is Commission Staff's position with respect to the White River**
3 **adjustment?**

4 A. The only part of PSE's adjustment that Commission Staff contests is the three-
5 year amortization period PSE is requesting for the deferred unrecovered
6 regulatory asset costs.¹⁰⁴

7 **Q. Why does Commission Staff oppose the three-year amortization period PSE**
8 **is requesting for these deferred costs?**

9 A. Commission Staff witness E. Cooper Wright claims the Commission approved the
10 current amortization period in a previous order with the caveat "to continue
11 amortizing these costs at the current depreciation rate until better information is
12 known related to sales and salvage values associated with this property."¹⁰⁵
13 Mr. Wright also claims PSE has not shown any new information that would alter
14 the Commission-established amortization rate.¹⁰⁶ PSE believes this part of the
15 order related to the status of the surplus properties, i.e., whether they could be
16 sold, which was an outstanding item at the time the order was issued and
17 continued to be an outstanding item until this rate case. PSE does not believe this
18 section of the Commission order related to the length of the amortization period.

¹⁰⁴ Wright, Exh. ECW-1T at 4:8-12.

¹⁰⁵ *Id.* at 16:18-21.

¹⁰⁶ *Id.* at 16.

1 **Q. What previous order is Mr. Wright referring to in his testimony?**

2 A. Mr. Wright is referring to Order No. 15 from PSE's 2003 Power Cost Only Rate
3 Case ("PORC"), Docket UE-031725, paragraph 44 in which the Commission
4 clarified its earlier order with respect to the accounting for the White River
5 Project and authorized PSE to defer the remaining undepreciated plant costs as a
6 regulatory asset and to continue amortizing these costs at the current depreciation
7 rate until better information is known related to sales and salvage values
8 associated with this property.

9 **Q. Does PSE agree with Mr. Wright's statement that PSE has not shown any**
10 **new information that would alter the Commission-established amortization**
11 **rate?**¹⁰⁷

12 A. No. As discussed in the Prefiled Direct Testimony of Paul K. Wetherbee,
13 Exh. PKW-1CT, "PSE has sold and has current or future needs for the remaining
14 properties."¹⁰⁸ Mr. Wright's testimony acknowledges Mr. Wetherbee's statement
15 with the following, "By the filing of this rate case, PSE had completed selling of
16 the property intended to be sold to other parties."¹⁰⁹ Mr. Wright states that "Staff
17 has reviewed the property transfers and has found them reasonable because each

¹⁰⁷ *Id.* at 17:4-6.

¹⁰⁸ Wetherbee, Exh. PKW-1CT at 78:9-10.

¹⁰⁹ Wright, Exh. ECW-1T at 15:9-10.

1 transfer meets the definition of each destination FERC account. The Company's
2 property transfers reflect good accounting practice."¹¹⁰

3 In Order 15, quoted above, PSE was allowed to defer the remaining undepreciated
4 White River plant costs as a regulatory asset and continue amortizing the costs at
5 an amortization rate equal to the approved depreciation rate when the White River
6 stranded plant was transferred to the regulatory asset because the Commission
7 wanted better information related to sales and salvage values associated with the
8 White River property. That better information the Commission was seeking is
9 now known.

10 **Q. Why does PSE believe that a three-year amortization period is appropriate**
11 **now that all the sales and salvage values associated with the White River are**
12 **known?**

13 A. The length of time PSE has held the regulatory asset is relevant when considering
14 PSE's proposal to amortize the deferral balance over a three-year period. Order
15 15, quoted above, is dated June 7, 2004. It has now been over 14 years since that
16 order came out.

17 PSE also believes there is precedent for the three-year amortization period based
18 on the amount of the regulatory asset compared to other amortizations approved
19 in PSE's 2009 and 2011 general rate cases in Dockets UE-090704 and UE-
20 111048 respectively. In the 2009 case, the Commission approved PSE's Wild

¹¹⁰ Wright, Exh. ECW-1T at 16:11-13.

1 Horse Expansion estimated annual amortization and net rate base amount for
2 deferred costs associated with the wind project, which went into service
3 November 9, 2009, until April 7, 2010 when the 2009 GRC rate year began. The
4 balances of the deferred costs associated with the Wild Horse Expansion at the
5 time the amortization was approved was \$5.6 million. The Commission approved
6 a two-year amortization period for this deferral.

7 In the 2011 PSE general rate case, the Commission approved PSE's estimated
8 annual amortization and net rate base amount for deferred costs associated with
9 Phase 1 of the Lower Snake River wind project, which went into service February
10 12, 2012, until May 12, 2012 when the 2011 GRC rates went into effect. The
11 balance of the deferred costs associated with the Lower Snake River wind project
12 was \$18.2 million. The Commission approved a four-year amortization period for
13 this deferral.

14 Like the White River deferral, these two deferrals are related to deferred plant
15 costs. The White River deferral balance and amortization period fall between each
16 of these referenced deferrals; therefore, PSE's request for a three-year
17 amortization period for the White River deferral is appropriate, especially in
18 consideration of the length of time PSE has held this regulatory asset.

19 Accordingly, the Commission should approve PSE's adjustment which has not
20 changed since the supplemental filing.

1 **K. Hydro-Related Treasury Grants, Adjustment KJB-21.12**

2 **Q. Would you please summarize PSE’s adjustment for the hydro-related**
3 **Treasury Grants?**

4 A. PSE has proposed to repurpose the hydro-related Treasury Grants and to transfer
5 the entire balance into a retirement account designated for decommissioning and
6 remediation expenses associated with Colstrip Units 1 and 2. PSE’s adjustment
7 remains unchanged from that presented in its direct testimony and in the
8 following section I address the various modifications to this adjustment proposed
9 by other parties

10 **Q. Would you summarize the position of the parties on PSE’s proposal to**
11 **repurpose the hydro-related Treasury Grants and PTC’s to address the**
12 **decommissioning and remediation costs for Colstrip Units 1 and 2?¹¹¹**

13 A. Yes. In general Sierra Club and Public Counsel support PSE’s proposal and
14 Public Counsel has accepted PSE’s adjustment to address decommissioning and
15 remediation at Colstrip Units 1 and 2. Commission Staff Witness Hancock
16 supports the repurposing with some modification, and ICNU witness Mullins
17 essentially rejects PSE’s proposal and has proposed a separate tracker that
18 addresses only the unrecovered plant and the estimated decommissioning and
19 remediation costs through 2029, then converts to a “pay as you go” scheme.¹¹²

¹¹¹ Further discussion on the use of PTCs to address decommissioning and remediation costs is found in Section VII of my testimony.

¹¹² Mullins, Exh. BGM-1CT at 32:7 - 37:6.

1 **Q. Please describe Commission Staff witness Mr. Christopher S. Hancock's**
2 **proposal for repurposing of the hydro-related Treasury Grants for Colstrip**
3 **Units 1 and 2 decommissioning and remediation.**

4 A. As described more fully in the Prefiled Rebuttal Testimony of Mr. Matthew R.
5 Marcelia, Exhibit MRM-1T, Mr. Hancock takes PSE's relatively straightforward
6 proposal to use existing regulatory liabilities to offset the decommissioning and
7 remediation costs associated with Colstrip Units 1 and 2, and proposes a far more
8 complex mechanism that essentially shifts a portion of those costs to PSE. For the
9 reasons discussed by Mr. Marcelia, the Commission should reject Mr. Hancock's
10 adjustment.

11 **Q. Please describe ICNU witness Mullins' proposal for addressing the**
12 **decommissioning and remediation costs of Colstrip Units 1 and 2.**

13 A. As described in the Prefiled Rebuttal Testimony of Mr. Marcelia, Exhibit MRM-
14 1T, Mr. Mullins rejects PSE's adjustment to repurpose the Treasury Grants and
15 proposes that a new and separate tracker be created to address both
16 decommissioning and remediation costs as well as any unrecovered plant as
17 discussed earlier in my testimony. For the reasons discussed below and by
18 Mr. Matthew Marcelia, the Commission should reject Mr. Mullins' adjustment.

1 **Q. Has Mr. Mullins correctly described the current treatment of the hydro-**
2 **related Treasury Grants?**

3 A. No. Mr. Mullins incorrectly states that both the hydro and Lower Snake River
4 Treasury Grants are currently being passed back to customers through Schedule
5 95A.¹¹³ Mr. Mullins is correct that the Treasury Grants related to the Lower Snake
6 River¹¹⁴ wind facility are being passed back to customers through Schedule 95A;
7 however, he has incorrectly described the current treatment of the hydro-related
8 Treasury Grants, which are currently included as a reduction or offset to PSE's
9 rate base.

10 **Q. Why are the hydro-related Treasury Grants included as a rate base offset?**

11 A. The regulatory treatment of the hydro-related Treasury Grants was part of the
12 settlement agreement in PSE's 2013 Power Cost Only Rate Case ("PCORC").¹¹⁵
13 In that case, parties agreed that rather than including the hydro-related Treasury
14 Grants in Schedule 95A, these Treasury Grants would be treated in a manner
15 equivalent to a reduction of rate base, and the grants were to be amortized over
16 the remaining life of the plant assets. The fact that the hydro-related Treasury
17 Grants are already reflected as a reduction to PSE's rate base is one of the reasons
18 PSE proposed to utilize them for the Colstrip Units 1 and 2 decommissioning and

¹¹³ *Id.* at 36:10-19.

¹¹⁴ It should be noted that Schedule 95A also passes back the Treasury Grants associated with the Wild Horse Expansion wind project that Mr. Mullins neglects to mention.

¹¹⁵ *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-130617, *et al.*, Order 6 at ¶ 65 (Oct. 23, 2015).

1 remediation. Additionally, use of the Treasury Grants and monetized PTCs as a
2 rate base offset is consistent with the treatment of negative salvage is addressed
3 when it is incorporated in depreciation rates. The only direct impact to customers
4 from the repurposing of the regulatory liabilities is the discontinuation of the
5 current amortization expense.

6 **Q. Is PSE proposing any change to the Treasury Grants associated with Lower**
7 **Snake River?**

8 A. No. PSE has not requested any change to the treatment of the Treasury Grants
9 associated with the wind projects that are currently passed back to customers
10 through Schedule 95A.

11 **L. Removal of Fixed Production Factor, Adjustment KJB-21.13**

12 **Q. Has PSE accepted Commission Staff's proposal regarding the fixed**
13 **production factor?**

14 A. Yes. As discussed in the Prefiled Rebuttal Testimony of Mr. Jon A. Piliaris,
15 Exhibit JAP-46CT, PSE accepts Commission Staff's proposal to set fixed
16 production costs at a fixed level rather than tie them to the number of customers,
17 as long as this is paired with Commission Staff witness Ms. Jing Liu's proposal to
18 eliminate the production factoring of these costs in the determination of allowed
19 revenue. ICNU has indicated they are neutral related to this adjustment.¹¹⁶

¹¹⁶ Mullins, Exh. BGM-3 at 1:41.

1 **Q. What is the amount of the production adjustment once the fixed production**
2 **factor is removed?**

3 A. Now that there is no longer a fixed production factor included in this adjustment,
4 the production factor applies only to variable items from the PCA mechanism,
5 such as the Montana Electric Energy Tax, that are not included in the power cost
6 adjustment, Adjustment KJB-21.01. After removing the fixed production factor,
7 this adjustment now results in an increase to net operating income of \$32,873 and
8 no change to rate base.

9 **Q. Did any other party question the production factor calculations?**

10 A. No, although Public Counsel witness Smith indicates they have accepted PSE's
11 fixed production factor,¹¹⁷ another Public Counsel witness, Michael L. Brosch,
12 advocates for "complete decoupling."¹¹⁸ It would be inappropriate to include the
13 production factor accepted by Mr. Smith, which reduces fixed production costs
14 for the differences in customers between test year and rate year levels, and then
15 deprive PSE of the opportunity to recover these costs at the rate year level
16 determined as appropriate in the Commission's final order. These two issues must
17 be handled consistently. Either fixed production costs should be production
18 factored based on customer growth and then allowed to grow with customers or
19 they should not be production factored and held constant at rate year levels.

¹¹⁷ Smith, RCS-3 Supplemental, 1:38, where it reflects "PC Accepted."

¹¹⁸ Brosch, Exh. MLB at 3:17-20.

1 **M. Regulatory Asset – Colstrip, Commission Staff Adjustment 13.06A**

2 **Q. Please describe Commission Staff’s adjustment for a Colstrip regulatory**
3 **asset.**

4 A. As discussed earlier in section V. B. of my testimony, Commission Staff witness
5 Mr. Chris R. McGuire creates a \$127 million reserve imbalance (regulatory asset)
6 associated with Colstrip Units 1 and 2 based on a “theoretical” level of
7 depreciation that he believes should have been collected between 1975 through
8 2017 when the new depreciation rates take effect. Under his proposal this
9 regulatory asset is to be amortized over 18 years, which coincides with the
10 previously assumed depreciable life (i.e., until 2035) of the facilities. His proposal
11 excludes the regulatory asset from rate base and fails to include any carrying
12 charges. For the reasons described earlier in my testimony and in the Prefiled
13 Direct Testimony of Mr. Matthew R. Marcellia, Exhibit MRM-1T, the
14 Commission should reject Commission Staff’s proposed adjustment.

15 **N. Legal Expense, Commission Staff Adjustments 13.24E and 11.24G**

16 **Q. Does Commission Staff propose an adjustment for legal expense?**

17 A. Yes, and Ms. Susan Free discusses the difference in the position of PSE and the
18 Commission Staff in Exhibit SEF-12T.

1 **O. Future Use Property, Public Counsel Adjustment B-5, ICNU and**
2 **NWIGU Adjustment IN-4**

3 **Q. What is the position of ICNU and NWIGU with respect to plant held for**
4 **future use?**

5 A. Mr. Brad G. Mullins for both ICNU and NWIGU recommends removal from rate
6 base of all electric and gas balances of plant held for future use. Mr. Mullins
7 states that PSE has not demonstrated that the properties are used and useful to
8 ratepayers.¹¹⁹

9 **Q Does PSE agree with Mr. Mullins' proposed adjustments?**

10 A. No. As discussed in the Prefiled Rebuttal Testimony of Matthew R. Marcellia,
11 Exhibit MRM-1T, Mr. Mullins testimony is not accurate in regards to the plant
12 held for future use and therefore should be rejected.

13 **Q. What does Public Counsel propose with respect to properties held for future**
14 **use?**

15 A. Public Counsel witness Smith recommends removal of two properties that are
16 currently part of plant held for future use.¹²⁰ These were first placed in future use
17 in 1992. Based on the Commission's Order in Dockets UE-920433, UE-920499
18 and UE-921262 and the fact that these two properties have been in future use for
19 more than 20 years, Mr. Smith recommends removing the properties shown
20 below:

¹¹⁹ *Id.* at 43:20 - 44:4.

¹²⁰ Smith, Exh. RCW-1CT at 20:4-11.

PP Asset		Vintage			9/30/2016	Date In	Projected	Super
Number	WO#	Year	FERC#	Description	Balance	Future Use	in-Service	Number
39060	CONV	1992	E350	BPA KITSAP Naval Trans Plant Land RTS	\$147,139	12/31/1992	10/1/2019	TLN-0052
39061	CONV	1992	E350	BPA KITSAP Naval Trans Plant Land RTS	\$289,426	12/31/1992	10/1/2019	TLN-0052
Total					\$436,566			

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2 **Q. Does PSE agree with Mr. Smith's Adjustment?**

3 A. No. As discussed by Mr. Marcelia, PSE has a stringent process to ensure that
4 plant held in future use has a specific plan. Although, Mr. Smith shows that the
5 land associated with these two properties have been held in future use longer than
6 the 20 year period, this is because the timing of the transmission line for which
7 the properties were acquired had to be extended as a result of the JPUD transition.
8 As provided in PSE's Response to ICNU Data Request No. 063, PSE explained
9 that this particular line upgrade is anticipated to be in place by 2019. Therefore, it
10 is appropriate to allow these properties to be held in future use.

11 **P. Proforma NOL to Zero, ICNU Adjustment IN-2**

12 **Q. Please discuss ICNU's adjustment with respect to net operating losses.**

13 A. Mr. Mullins for ICNU and NWIGU has proposed a pro forma adjustment to
14 eliminate the net operating losses currently included in PSE's rate base
15 calculation. Mr. Matthew Marcelia discusses the differences in the positions of
16 PSE and ICNU for this adjustment.¹²¹

¹²¹ See Marcelia, Exh. MRM-1T.

1 **Q. Amortize PTCs, ICNU Adjustment IN-3**

2 **Q. Please discuss ICNU's adjustment to amortize PTCs.**

3 A. ICNU witness Mullins has proposed a pro forma adjustment to commence
4 amortization on the PTCs that PSE has not yet utilized on its tax returns.¹²²
5 Mr. Matthew Marcellia discusses the differences in the positions of PSE and
6 ICNU for this adjustment. *See* Exhibit MRM-1T. There is further discussion later
7 in my testimony regarding PTCs.

8 **R. Ardmore Substation Overruns, ICNU Adjustment IN-6**

9 **Q. Please discuss ICNU's adjustment with respect to the Ardmore Substation.**

10 A. ICNU witness Mullins has reduced the Ardmore Substation construction costs by
11 \$13.6 million based on his claim of cost overruns as compared to PSE's \$25.9
12 million budget.¹²³

13 **Q. Does PSE agree with Mr. Mullins' Adjustment to reduce the Ardmore**
14 **Substation by \$13.6 million?**

15 A. No. PSE does not agree with Mr. Mullins adjustment to reduce the Ardmore
16 Substation by \$13.6 million. As described in the Prefiled Rebuttal Testimony of
17 Catherine A. Koch, Exhibit CAK-4T, the project was constructed prudently and
18 the ultimate costs are, in part, related to the expanded scope of the project, which
19 included retiring the Interlaken Substation and combining it within the Ardmore

¹²² Mullins, Exh. BGM-1CT at 32:7 – 37:6.

¹²³ *Id.* at 54:8-12.

1 Substation footprint. Mr. Mullins' assertions are incorrect and his proposed
2 adjustment should be rejected.

3 **VI. CHANGES BY PSE AT REBUTTAL**

4 **Q. PSE had identified adjustments that it would update over the course of the**
5 **proceeding. Has PSE made these updates?**

6 A. No. When PSE made its initial filing it recognized that a number of adjustments
7 could require updating as better information became available over the course of
8 the proceeding. The adjustments that originally contemplated updates that have
9 not changed are the Property and Liability Insurance Adjustment KJB-20.14E and
10 15.14G, Employee Insurance Adjustment KJB-20.18E and 15.18G, South King
11 Service Center Adjustment KJB-20.21 and 15.21G, Energy Imbalance Market
12 Adjustment KJB-21.08¹²⁴ and Mint Farm Adjustment KJB-21.10. All of these
13 adjustments are uncontested as to their amounts and considering the materiality
14 thresholds applied by Commission Staff, none of the updates originally
15 anticipated by PSE are materially different from the adjustments included in
16 PSE's supplemental filing. Therefore, PSE has not proposed updates for these
17 adjustments in this rebuttal filing.

¹²⁴ Although the Energy Imbalance Market Adjustment 21.08 is contested, the amount is not.

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**VII. USE OF PRODUCTION TAX CREDITS
TO FUND COLSTRIP COSTS**

Q. Why has PSE proposed to repurpose both the hydro-related Treasury Grants and Production Tax Credits to address Colstrip Units 1 and 2 costs?

A. As described in both my prefiled direct testimony and the Prefiled Direct Testimony of Mr. Daniel A. Doyle, Exhibit DAD-1T, PSE’s proposal serves the purpose of mitigating negative rate impacts and intergenerational inequities that would otherwise occur when addressing the remaining life of Colstrip Units 1 and 2.

Q. Mr. Hancock states that “intergenerational tradeoffs are simply unavoidable on this matter ... and we are left with the task of mitigating intergenerational inequities, not resolving them.”¹²⁵ Do you agree with his statement?

A. No, I do not agree with his statement. With respect to addressing the undepreciated balance of Colstrip Units 1 and 2 at its expected retirement date of July 1, 2022, I believe the intergenerational inequities can be almost entirely avoided through the use of PTCs. Once they are monetized on a tax return, the PTCs can be held in a separate retirement account and applied towards the undepreciated balance. Additionally, there may be opportunities to utilize the PTCs to address Colstrip Units 3 and 4 costs in a way that avoids intergenerational inequity as well.

¹²⁵ Hancock, Exh. CSH-1T at 16:11-15.

1 **Q. How does the use of PTCs to address Colstrip end of service issues avoid**
2 **intergenerational inequities?**

3 A. As discussed earlier in section V. B. of my testimony, customers received the
4 benefit of lower depreciation rates for all four Colstrip units during the 2009¹²⁶
5 through 2017 period due to the extension of the assets depreciable life to 60 years.
6 Additionally, this period is closely aligned with the period that the PTCs were
7 generated, but due to ongoing net operating losses PSE has not been able to be
8 utilize these PTCs on its tax return. The use of some of the monetized PTCs to
9 address the undepreciated balance, is a reasonable approach.

10 **Q. Does reserving the monetized PTCs address other concerns identified by**
11 **parties in planning for the eventual closure of the Colstrip facilities?**

12 A. Yes. Both NWECC and Sierra Club claim that better planning needs to occur for
13 the eventual retirement of Colstrip Units 3 and 4 and that there are lessons to be
14 learned from the change in circumstances with Colstrip Units 1 and 2.¹²⁷ While I
15 do not agree with their assessment that there was “poor planning” around the
16 retirement of Colstrip Units 1 and 2, I do agree that planning for the uncertainty
17 around the eventual retirement of the Colstrip Units 3 and 4 in order to minimize
18 customer rate impacts is important. Retaining the PTCs once they have been
19 monetized, in a separate retirement account that is a rate base offset is a way to
20 achieve that “better planning” and will prevent any future intergenerational

¹²⁶ The depreciation rates approved in UE-072300 became effective in November 2008.

¹²⁷ See, e.g., Hausman, Exh. EDH-1T at 6:5-14; Power, Exh. TMP-1T at 12:2 – 15:3.

1 equities that could occur should circumstances change that further shorten the life
2 of any of the Colstrip units. Additionally, as I discussed earlier, the rate base
3 offset treatment is representative to how the negative salvage and accumulated
4 depreciation reserve would be treated.

5 **Q. Did you originally propose to include the entire balance of monetized PTCs**
6 **in the Colstrip retirement account to be established under RCW**
7 **80.84.020(2)(a) for decommissioning and remediation?**

8 A. Yes. However, since the existing hydro-related Treasury Grants addressed in
9 Adjustment KJB-21.12 fund nearly all of the estimated decommissioning and
10 remediation costs for Colstrip Units 1 and 2, I believe it would be appropriate to
11 place the monetized PTCs in a retirement account, separate from the
12 decommissioning and remediation retirement account established under RCW
13 80.84.020(2)(a) that is funded using the Treasury Grants. This retirement account
14 would be treated as a rate base offset, like the dedicated decommissioning and
15 remediation account, but could be used to address any under recovered plant
16 balances associated with Colstrip (Units 1 through 4) facilities that may arise.

17 **Q. Do you agree with Mr. Hancock that once funds are placed into a retirement**
18 **account established under RCW 80.84.020(2)(a), the funds may not be used**
19 **for any purpose other than decommissioning and remediation?**

20 A. Yes, Mr. Hancock is correct that once placed in a retirement account established
21 under RCW 80.84.020(2)(a) the funds may not be utilized for any purpose other
22 than decommissioning and remediation costs associated with an eligible coal unit.

1 However, this does not prevent the Commission from allowing the PTCs to be
2 included in a retirement account, separate and apart from an account created
3 pursuant to RCW 80.84.020(2), to be used to address any unrecovered plant
4 balances associated with the Colstrip facilities.

5 **Q. Will that leave the Colstrip Units 1 and 2 decommissioning and remediation**
6 **funds underfunded?**

7 A. Not necessarily. As identified in the Prefiled Direct Testimony of Mr. Daniel A.
8 Doyle, Exhibit DAD-1T, at this time it is estimated that only \$11 million of the
9 PTCs would be needed to fund the decommissioning and remediation costs for
10 Colstrip Units 1 and 2. By retaining all monetized PTCs in a retirement account
11 separate from the Treasury Grants, the Commission would have the flexibility to
12 address what portion of the PTCs should be designated for decommissioning and
13 remediation at a later date.

14 **Q. Would the accounting for this PTC retirement account be different than that**
15 **proposed in your prefiled direct testimony?**

16 A. No, the only difference is that a separate account would be established to track the
17 PTCs once they were monetized. My direct testimony, envisioned that once the
18 PTCs were utilized for tax purposes that instead of passing the funds back through
19 a Schedule 95A rate change, PSE would credit the FERC 108 retirement account
20 established for Colstrip Units 1 and 2.¹²⁸ In light of the concerns identified by

¹²⁸ Barnard, Exh. KJB-1T at 84:21 – 85:15.

1 both Mr. Hancock and Mr. Mullins that once the funds are placed in the RCW
2 80.84.020(2)(a) retirement account they may not be redistributed until all
3 remediation is completed,¹²⁹ the monetized PTCs could be placed into a separate
4 FERC 108 account but still treated as a rate base offset as discussed in my
5 prefiled direct testimony.

6 **Q. Do you agree with Mr. Mullins' statement that it is "not in the best interest of**
7 **Washington ratepayers to fund remediation expenses today which the**
8 **Company will not make for another 30 years"?**¹³⁰

9 A. No. Under traditional ratemaking, the goal is to have customers who have
10 received the benefits of the generation pay the costs, including the
11 decommissioning and remediation, associated with those assets. Under
12 Mr. Mullins' proposal, future customers who have never received the benefit of
13 the generation would likely be left paying for costs associated with the facility.

14 **Q. How do you propose that customer's receive the benefit of the PTCs when**
15 **they are monetized?**

16 A. I propose to treat the monetized PTCs in the same manner as the hydro-related
17 Treasury Grants and to utilize deferral treatment of the same type that is
18 authorized under RCW 80.80.060¹³¹ until their rate base impact is incorporated in

¹²⁹ Hancock, Exh. CSH-1CT at 16:3-15; Mullins, Exh. BGM-1CT at 34:12-18.

¹³⁰ Mullins, Exh. BGM-1CT at 17:7-9.

¹³¹ RCW 80.80.060(6) provides for the deferral of costs associated with long-term financial commitments related to baseload electric generation.

1 base rates in a future proceeding. This will allow customers to receive the full
2 benefit associated with the PTCs and avoid the situation in which PSE refunds
3 dollars through PTC early amortization only to turn around and increase rates in
4 the future for unrecovered costs at the Colstrip units— especially recognizing
5 those future customers received no benefits from Colstrip.

6 **Q. Please summarize your recommendation?**

7 A. I recommend that the Commission authorize PSE to place the PTCs, as they are
8 monetized, into a separate FERC 108 retirement account that will be a dedicated
9 to addressing any undepreciated plant associated with any Colstrip units. The
10 PTCs, once monetized, would defer the related cost of capital consistent with the
11 approach outlined in RCW 80.80.060(6), until the retirement account is
12 incorporated into rates.

13 **VIII. EXPEDITED RATE FILINGS**

14 **Q. What was the overall response to PSE's proposal to formalize the expedited**
15 **rate filing procedures?**

16 A. Public Counsel, ICNU, and FEA are opposed to PSE's request that the
17 Commission formalize the expedited rate filing process utilized in Dockets UE-
18 130137 and UG-130138. The following portion of my testimony will address their
19 various concerns.

1 **Q. Does Commission Staff support PSE’s proposal to formalize the expedited**
2 **rate filing procedures as requested by PSE.**

3 A. Yes. Commission Staff’s testimony recognizes that the Commission currently has
4 a pending rulemaking, Docket A-130355, which may include procedures for a
5 “limited rate filing.” Mr. Schooley, in his response, to Public Counsel Data
6 Requests 2, 4, 6 and 7, which are included as Exhibit KJB-36, indicates he
7 supports PSE’s proposal for an expedited rate filing based on the methods used
8 and approved in Dockets UE-130137 and UG-130138 in the absence of actual
9 rules for such a filing.¹³²

10 **Q. Please summarize the positions of the other parties?**

11 A. FEA’s witness Mr. Ali Al-Jabir, Public Counsel witness Mr. Michael L. Brosch,
12 and ICNU witness Mr. Michael P. Gorman all advocate that the Commission
13 reject PSE’s proposal and allow changes in base rates to occur only through a
14 general rate proceeding where all costs, including cost of capital can be
15 reviewed.¹³³

16 **Q. Do you believe that an update to cost of capital needs to be included in an**
17 **expedited rate filing proceeding?**

18 A. No. All three parties object to an expedited rate filing, in part because it does not
19 include an update to cost of capital. Their concerns that the cost of capital

¹³² Barnard, Exh. KJB-36 at 9.

¹³³ Al Jabir, Exh. AZA-1T at 3:11 – 4:5; Brosch, Exh. MLB-1T at 36:12-23; Gorman, Exh. MPG-1T at 36:12-23.

1 information will be stale, or that conditions could have changed since the rates
2 were last set, I believe are over exaggerated and fail to recognize that a full review
3 of all costs, including cost of capital will have occurred in the recently concluded
4 general rate case filing. The expedited rate filing is intended to be limited in
5 nature, to provide for a limited update to costs while breaking the cycle of back to
6 back general rate cases. Assuming that the expedited rate filing is allowed for up
7 to two years after the cost of capital has been determined in a general rate case, it
8 should be unnecessary for the Commission to require a full cost of capital study to
9 be undertaken in an expedited rate filing. Utilization of the previously approved
10 cost of capital is also consistent with prior Commission orders in which the
11 previously authorized return on equity remained unchanged, when the
12 Commission had recently determined PSE's cost of capital in a general rate
13 case.¹³⁴

14 **Q. How do you respond to the parties concerns about the expedited time line?**

15 A. Mr. Brosch, Mr. Gorman and Mr. Al-Jabir express concern about the expedited
16 schedule,¹³⁵ but what they fail to recognize is that the expedited rate filing or
17 limited rate filing is intended to be only a limited update. By utilizing the
18 Commission Basis Report format that is well established and includes only
19 limited restating adjustments with consistent methodologies, this will allow the

¹³⁴ *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co., a Division of PacifiCorp*,
Dockets UE-140762, *et al.*, Order 08 at ¶ 181 (Mar. 25, 2015).

¹³⁵ Brosch, Exh. MLB-1T at 70:2-9; Gorman, Exh. MPG-1T at 36:12-23; Al Jabir, Exh.
AZA-1T at 31:1 – 32:7.

1 review to be completed in an expedited manner without prejudice to any party. By
2 removing power costs and pro forma adjustments, which typically are more
3 contentious, the expedited timeline is reasonable. Commission Staff concurs that
4 an expedited rate filing can be completed in this timeframe.¹³⁶

5 **Q. Mr. Brosch suggests that an expedited rate filing should be limited to a**
6 **period of 12 months after the issuance of the final order in a general rate case**
7 **rather than the two year period that PSE originally proposed.¹³⁷ Do you**
8 **agree with that timeframe?**

9 A. Not entirely. I support the filing of an initial expedited rate filing within 12
10 months of the final order from a general rate case proceeding, however, I believe
11 PSE should have the ability to file a second ERF within the 12 months following
12 the completion of an expedited rate filing, a process that was discussed in the
13 draft rules. The opportunity to file more than one expedited rate filing is
14 consistent with the approach proposed by Public Counsel in PSE's
15 Decoupling/Expedited Rate Filing proceeding. In that 2013 case, Public Counsel
16 opposed the multi-year rate plan and proposed that instead of the K-Factor, PSE
17 be allowed to file two expedited rate filings within the stay-out period.¹³⁸

¹³⁶ See Barnard, Exh. KJB-36 at 8 (Commission Staff Response to Public Counsel Data Request No. 6, in which Commission Staff states as follows: "Given the limited number of adjustments and, therefore, the limited nature of such a review, Staff accepts this quick timeframe. The review should be able to be accomplished on an expedited basis because the filing includes only the standard restating ratemaking adjustments, uses existing methodologies previously approved by the Commission and excludes pro forma adjustments.")

¹³⁷ Brosch, Exh. MLB-1T at 65:1-2.

¹³⁸ Dockets UE-130137, *et al.*, Dittmer, Exh. JRD-1T at 41:14-16.

1 **Q. Mr. Gorman claims that an expedited rate filing would discourage efficient**
2 **company operations.¹³⁹ Do you agree?**

3 A. No. PSE always has an incentive for efficient operations, and, even with an
4 expedited rate filing, PSE must be able to support that the costs included in its
5 filing are reasonable. Moreover, to the extent parties believe that regulatory lag
6 encourages efficiency, the expedited rate filing does not completely remove
7 regulatory lag—it only serves to lessen it. As PSE demonstrated in its 2013
8 proceeding, under the traditional ratemaking model PSE was unable to earn its
9 authorized rate of return for several years, despite filing multiple rate proceedings.
10 Therefore, the expedited rate filing provides a reasonable and balanced approach
11 that continues to encourage efficient operations.

12 **Q. Public Counsel discusses the number of “new adjustments” that occur in a**
13 **general rate case that would not be included in an expedited rate filing.**
14 **Should this be a concern?**

15 A. No. Public Counsel compares the number of adjustments included in a general
16 rate case to the limited adjustments that are included in a Commission Basis
17 Report and distorts the difference to illustrate what Public Counsel views to be “a
18 very basic problem with the ERF process.”¹⁴⁰ Mr. Brosch fails to recognize that
19 the majority of the “new adjustments” that are “unique” to a particular general
20 rate case tend to be one time annualizing or pro forma adjustments that are

¹³⁹ Gorman, Exh. MPG-1T at 38:21-22.

¹⁴⁰ Brosch, Exh. MLB-1T at 66:13-16.

1 typically recognizing increases in costs that will be in place during the rate year;
2 therefore the exclusion of these adjustments *benefits* customers, it does not harm
3 customers. One of the things PSE forgoes by utilizing an expedited rate filing as
4 opposed to a general rate case is the use of pro forma adjustments which typically
5 recognize increases or changes in costs that occur outside of the test year; in
6 return the process is more streamlined.

7 **Q. How do you respond to Mr. Brosch's statement that PSE has not**
8 **demonstrated that it will face attrition and therefore PSE's request to**
9 **formalize the expedited rate filing procedures should be rejected?**¹⁴¹

10 A. I disagree with Mr. Brosch's assertion that a showing of attrition is necessary for
11 an expedited rate filing, and Mr. Brosch provides no support for his viewpoint. As
12 Mr. Schooley acknowledges in Commission Staff's Response to Public Counsel
13 Data Request No. 2, the Commission did not state in 2013 that attrition must be
14 shown.¹⁴² PSE has in the past filed both a gas tariff increase filing¹⁴³ and an
15 expedited rate filing¹⁴⁴ that are limited scope filings to update costs. Neither the
16 procedural rules nor the Commission past order have required a showing of
17 attrition before such filings can be considered. The point here is to add some
18 certainty to these proceedings and from PSE's and Commission Staff's

¹⁴¹ *Id.* at 69:11.

¹⁴² Barnard, Exh. KJB-36 at 2.

¹⁴³ Docket UG-101644.

¹⁴⁴ Dockets UE-130137 & UG-130138.

1 perspective, the 2013 expedited rate filing is a good model to follow in terms of
2 the procedural timeframe and the scope of the proceeding.¹⁴⁵

3 **Q. ICNU witness Mr. Gorman claims an expedited rate filing is single issue**
4 **ratemaking.¹⁴⁶ Do you agree?**

5 A. No. Mr. Gorman's assessment that an expedited rate filing is single issue
6 ratemaking is misplaced. Single issue ratemaking tends to be when only one
7 element of the costs are being addressed. An ERF is intended as an update to all
8 non-production delivery costs which, based on Washington's modified historical
9 test period and use of limited pro forma adjustments, are often stale by the time
10 the rates established in the general rate case become effective. For example, the
11 rates to be established in this general rate case will be effective more than 14
12 months after the end of the test year and because they are based on the average of
13 monthly average ("AMA") balances, assets placed in service near the end of the
14 test year are often only partially reflected in the test year. The exclusion of power
15 costs does not result in an expedited rate filing being single issue ratemaking, but
16 instead recognizes that power costs are set on a future basis utilizing information
17 as close as possible to the estimated costs in the rate year.

¹⁴⁵ Barnard, Exh. KJB-36 at 7.

¹⁴⁶ Gorman, Exh. MPG-1T at 36:13-14.

1 **Q. How do you respond to Mr. Brosch and Mr. Gorman who both indicate PSE**
2 **can choose which costs to include in and expedited rate filing?**

3 A. Both Mr. Gorman and Mr. Brosch make accusations that PSE can cherry pick and
4 include only “certain costs for ERF review.”¹⁴⁷ This is simply not true. The
5 expedited rate filing format that PSE used and that the Commission approved was
6 based on the format proposed by Commission Staff in the 2011 general rate case.
7 It included a complete matching of revenues and expenses associated with non-
8 production related assets. As discussed in that original expedited rate filing,
9 excluding power costs made sense for a number of reasons, the primary one being
10 the power costs are typically reviewed on a forward looking basis and as a result
11 would add unneeded complexity to a filing that is intended to be “expeditious”. In
12 filing an expedited rate filing, PSE gives up the opportunity to propose pro forma
13 adjustments, thus streamlining the process. With the filing occurring within one to
14 two years of the completion of a general rate case, an expedited rate filing merely
15 represents an update to cost information during the pendency of the case.
16 The arguments of ICNU and Public Counsel were rejected by the Commission in
17 2013 when PSE’s original expedited rate filing was accepted and they should be
18 rejected again.

¹⁴⁷ Gorman, Exh. MPG-1T at 36:14-16; Brosch, Exh. MLB-1T at 13:10-12.

1 **IX. ELECTRIC COST RECOVERY MECHANISM**

2 **Q. What is the position of the parties regarding PSE’s Electric Reliability Plan**
3 **and its associated Electric Cost Recovery Mechanism?**

4 A. As addressed in the Prefiled Rebuttal Testimony of Catherine A. Koch, Exhibit
5 CAK-4T, all parties oppose the electric cost recovery mechanism (“ECRM”).

6 **Q. Are the expenditures to be included in the ECRM embedded in PSE’s**
7 **ongoing distribution system maintenance and modernization expenditures?**

8 A. No. The Electric Reliability Plan as proposed by Ms. Koch and its associated cost
9 recovery mechanism represent accelerated replacement of high molecular weight
10 (“HMW”) cable and worst performing circuits (“WPC”) beyond the historic
11 spending levels with the intention to drive reliability improvements beyond the
12 historic levels and eliminate future outages. Moreover, these reliability
13 investments do not create new sources of revenue.

14 **Q. ICNU suggests recovery of costs in a rider are only appropriate when those**
15 **costs are significant, volatile, and beyond the utility’s control.¹⁴⁸ Do you**
16 **agree?**

17 A. No. The proposed plan and mechanism is intended to follow similar processes
18 that have evolved with the gas pipeline replacement plan and cost recovery
19 mechanism and I believe is consistent with the transparency the Commission

¹⁴⁸ Gorman, Exh. MPG-1T at 42:18-19.

1 sought in a recent Avista general rate case, when the Commission questioned the
2 higher level of investment in replacing Avista’s aging infrastructure.¹⁴⁹

3 **Q. How does PSE respond to Commission Staff’s position that the ECRM is not**
4 **needed because PSE “will receive rates to recover any investment after that**
5 **investment is in service and in the due course of Commission**
6 **proceedings”?**¹⁵⁰

7 A. Unfortunately, Commission Staff is ignoring the fact that “due course” is typically
8 27 months after the investment has been placed in service and providing benefits
9 to customers. The heightened level of annual expenditures associated with the
10 accelerated reliability improvements outlined in the Electric Reliability Plan
11 would result in significant earnings erosion absent the ECRM mechanism. Exhibit
12 KJB-37¹⁵¹ demonstrates the regulatory lag that would be associated with having
13 to absorb the level of investment contemplated in the Electric Reliability Plan.
14 This exhibit demonstrates that under traditional ratemaking that utilizes average
15 of monthly average (“AMA”) balances, it takes a full 12 months before the entire
16 investment is reflected in the AMA test year balance. Assuming that a rate case
17 can be prepared and filed in three months, plus the 11 months associated with the
18 statutory suspension period prior to approval in rates, it is more than two years
19 before PSE begins to recover its costs through rates. The two-year delay in
20 recovery of the 2017 ECRM investments would be equal to approximately

¹⁴⁹ *WUTC v. Avista*, Docket UE-150204/UG-150205, Order 05 ¶ 116.

¹⁵⁰ Schooley, Exh. TES-1T at 28:17-18.

¹⁵¹ Excerpt from PSE’s Response to Public Counsel Data Request No. 72.

1 \$20 million of lost revenue requirement which is nearly 20 basis points per year in
2 earnings.

3 Additionally, it is disappointing to see Commission Staff's complete rejection of
4 the ECRM particularly when one considers Commission Staff's recent position on
5 increased reliability spending by another regulated utility. In Commission Staff's
6 testimony in the Avista 2015 general rate case, Commission Staff "questioned the
7 need for Avista to "invest heavily" in distribution plant because Avista has not
8 provided evidence supporting the need to maintain or improve reliability."¹⁵² In
9 that case, Commission Staff further stated that:

10 without knowing where Avista should be in terms of its reliability
11 performance, it is not possible to know whether improved
12 "reliability" is a remotely acceptable cause for significant and
13 continued investment in distribution system enhancements. It is
14 entirely possible that, given the unique characteristics of Avista's
15 service territory, it has already invested far too heavily in
16 distribution system enhancements¹⁵³

17 The Commission agreed with Commission Staff's observation and stated we
18 "emphasize that we share Commission Staff's frustration about continuing to
19 authorize recovery for these significant capital investments, *absent a complete*
20 *demonstration by the Company of quantifiable benefits to ratepayers.*"¹⁵⁴

21 PSE, through the prefiled direct testimonies of Booga K. Gilbertson and Catherine
22 A Koch, have demonstrated a clear need to improve PSE's reliability and have

¹⁵² *Wash. Utils. & Transp. Comm'n v. Avista*, Dockets UE-150204 and UG-150205, Order 5 at ¶ 81 (Jan. 6, 2016).

¹⁵³ *Id.* at ¶ 98 referencing McGuire, Exh. CRM-1T at 24:19-21.

¹⁵⁴ *Id.* at ¶ 141 (emphasis added).

1 provided the Electric Reliability Plan as a pathway to improved reliability and the
2 anticipated improvements that will result from these investments. Rather than
3 embracing the opportunity to participate in constructive dialog, parties including
4 Commission Staff believe that PSE's filing along with the associated cost
5 recovery mechanism will be burdensome. Absent this process, PSE will be
6 reluctant to spend beyond the levels supported by growth.

7 **Q. Mr. Gorman with ICNU suggests that the infrastructure included in the**
8 **ECRM will also be accounted for in the ERF. Is this true?**

9 A. No. As discussed in my prefiled direct testimony, an expedited rate filing would
10 exclude costs associated with both the Gas CRM and electric CRM, as an
11 expedited rate filing is intended to exclude those costs included in a tracking
12 mechanism. Additionally, the expedited rate filing is not intended to address the
13 ongoing accelerated spending like that proposed in the electric reliability plan. An
14 ERF is limited to one, possibly two, filings after the completion of a general rate
15 case, where the ECRM is intended to address cost recovery of the accelerated
16 replacement of targeted reliability spending that will occur annually over the next
17 several years as outlined in Ms. Koch's testimony. Additionally, until the
18 Commission's rules are finalized, there is still uncertainty about the timing of
19 recovery under an ERF, whereas with the ECRM, the investments for that
20 program year are incorporated annually into rates providing the certainty and
21 timely recovery necessary to accelerate the spending. Finally, and equally as
22 important, is the transparency that the ERP and associated ECRM provides in

1 terms of the stakeholder review of accelerated capital spending that would be
2 devoted to specific reliability improvements.

3 **Q. Is PSE proposing a change to the revenue requirement associated with the**
4 **proposed ECRM mechanism?**

5 A. Yes. As discussed in my prefiled direct testimony, PSE indicated that at rebuttal it
6 would include what would normally be included in the annual ECRM filing.
7 Exhibit KJB-38 is an updated Electric CRM calculation based on the actual
8 amounts of HMW and WPC spending from January through May of 2017 and the
9 forecasted amounts for June through December 2017. As discussed in my prefiled
10 direct testimony, this is consistent with the approach utilized in the Gas CRM, in
11 which PSE makes an initial filing for the program year and then updates the filing
12 replacing the budgeted figures with actual expenditures.

13 **Q. Did any party challenge the proposed calculation of the ECRM associated**
14 **revenue requirement?**

15 A. No. Parties challenged the necessity of the mechanism and are opposed to the
16 separate tracker which is addressed in detail in the Prefiled Rebuttal Testimony of
17 Catherine A. Koch, Exhibit CAK-4T. No one challenged the revenue requirement
18 calculations, nor did they find them unreasonable or inconsistent with the
19 approach used for the Gas CRM.

1 **X. MATERIALITY AND OTHER NON-REVENUE**
2 **REQUIREMENT ISSUES**

3 **Q. Please address Commission Staff witness Schooley’s proposal to eliminate**
4 **certain adjustments from future filings.**

5 A. In general, PSE would be supportive of discontinuing the small adjustments as
6 proposed by Mr. Schooley.¹⁵⁵ Many of these adjustments were the result of
7 proposed adjustments by Commission Staff or other parties in prior proceedings
8 that were ultimately approved by the Commission, either because PSE did not
9 contest them or they were explicitly approved in the final order. Therefore, PSE
10 was reluctant to unilaterally omit them absent a Commission order allowing such
11 exclusion.

12 **Q. Ms. Cheesman proposes a materiality threshold for reviewing and including**
13 **certain adjustments?¹⁵⁶**

14 A. In general, PSE would be supportive of discontinuing the small adjustments that
15 are below Ms. Cheesman’s proposed materiality thresholds. Additionally, PSE
16 would support filing its revenue requirement numbers to the nearest \$1,000 for
17 operating expense and revenues and the nearest \$100,000 for rate base items,
18 which would be another natural way to avoid including immaterial amounts in
19 rate case filings.

¹⁵⁵ Schooley, Exh. TES-1T at 17:19-22.

¹⁵⁶ Cheesman, Exh. MCC-1T at 23:13-19.

1 **Q. Ms. Cheesman includes several pages in her testimony regarding**
2 **communication and the need for clarity in PSE’s terminology and**
3 **adjustment files.¹⁵⁷ Do you agree with her assessment?**

4 A. In general, PSE is open to improvements that will facilitate the review of the
5 numerous files that are provided to support of PSE’s rate request by Commission
6 Staff and the other parties to the case. PSE utilized both the format of the files and
7 the terminology such as the phrase “proforma revenue adjustment” consistent
8 with numerous past general rate case filings, where the format and terminology
9 had not been previously questioned. PSE recognizes that there are a number of
10 new Commission Staff members working on PSE’s filings and, PSE is open to
11 utilizing different terminology going forward to the extent the parties believe it is
12 clearer.

13 **XI. CONCLUSION**

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

15 A. Yes.

¹⁵⁷ *Id.* at 26:11 - 30:6.