**EXH. KJB-17T  
DOCKETS UE-170033/UG-170034  
2017 PSE GENERAL RATE CASE  
WITNESS: KATHERINE J. BARNARD**

**BEFORE THE**

**WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

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| **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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**PUGET SOUND ENERGY**

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

# I. INTRODUCTION

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

A. Yes.

Q. What is the purpose of your rebuttal testimony?

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

# II. COMPARISON OF PSE’S ELECTRIC BASE RATES REVENUE DEFICIENCY AND PARTIES’ REVENUE DEFICIENCIES

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

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

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

A.Yes. The impact on net operating income and rate base for each PSE adjustment is summarized on pages 1 through 6 of Exhibit KJB-19. I have also prepared Exhibits KJB-20 and KJB-21, which contain the detail pages supporting the summarized adjustments in Exhibit KJB-19. Exhibits KJB-19 through KJB-21 are presented in the same format as Exhibits KJB-12 through KJB-14, and in the same format as Ms. Cheesman’s Exhibit MCC-2. Exhibit KJB-22 provides the updated Exhibit A-1 Power Cost Baseline Rate for use in the Power Cost Adjustment (“PCA”) Mechanism.[[1]](#footnote-2) Finally, Exhibit KJB-23 provides an additional overview of all electric adjustments as to whether they are contested or uncontested and the effect on net operating income, rate base, and the contribution to the base rates revenue deficiency when comparing the results between PSE and other parties. Each of these adjustments is explained by reference to the actual adjustment page as listed below. PSE requests that the Commission accept the adjustments included in these exhibits as presented by PSE.

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

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

**Table 1**

|  |
| --- |
|  |

Q. What are the major differences between PSE’s electric revenue deficiency and the parties’ electric revenue deficiency?

A. Included in Exhibit KJB-23 is a comparison of the revenue deficiencies by adjustment currently filed by PSE and opposing parties. The major differences between PSE and opposing parties are (i) capital structure, (ii) return on equity embedded in the rate of return, and (iii) the other differences highlighted in Table 1 above. The capital structure and return on equity are discussed by Mr. Doyle and Dr. Morin in their prefiled rebuttal testimony, Exhibit DAD-7T and Exhibit RAM-12T, respectively. The other differences will be discussed in the relevant pro forma or restating adjustment discussions, which occur later in my testimony.

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

A. Yes. During discovery, PSE received Commission Staff’s Response to PSE Data Request Nos. 27 and 28, which reflect revisions and corrections to Commission Staff’s working capital calculation as well as to Commission Staff’s electric depreciation study adjustment that affected Commission Staff’s electric revenue requirement filed on June 30, 2017. Commission Staff’s response to PSE’s data request provided updated work papers for Exhibits BAE-2 and BAE-3, as well as Exhibits MCC-2, MCC-3 and MCC-5. I have provided an excerpt of Commission Staff’s response to PSE Data Request No. 27 as Exhibit KJB-24. I have also provided Commission Staff’s Response to PSE Data Request No. 17 in Exhibit KJB-25, which provides an explanation for Commission Staff’s change to their electric depreciation study adjustment. Ms. Free discusses and provides an excerpt from Commission Staff’s Response to PSE’s Data Request No. 28 which outlines the Commission Staff’s changes related to the working capital calculation. PSE is providing these data request responses because they illustrate the need for a correction to Commission Staff’s electric depreciation study and to also illustrate that PSE and Commission Staff have many fewer differences in position related to working capital once Commission Staff’s Response to PSE Data Request Nos. 27 and 28 are taken into account versus what is reflected in Table 1 above.

# III. MULTI-YEAR RATE PLAN

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

A. Public Counsel witness Brosch questions the “per customer” comparison of expenses presented as Tables 1, 2, and 3 in my prefiled direct testimony, Exhibit KJB-1T, and opines that the comparison should have been on growth in expenses because the use of expense per customer “dilutes the apparent rate of expense growth.”[[2]](#footnote-3) His criticism is surprising considering Public Counsel took the opposite view in 2013. In the 2013 decoupling case,[[3]](#footnote-4) Public Counsel criticized the use of growth in actual expenses rather than the “per customer” figures that PSE had originally used to support the K-Factor figures that were part of the multi-year rate plan.

Regardless, whether comparing total non-production operations and maintenance (“O&M”) expenses in total or on a per customer basis, the tables in my prefiled direct testimony do demonstrate that the annual growth rate in expenses during the rate plan period were lower than the historical growth trend in PSE’s non-production O&M and are in line with the goals established for the rate plan. Between 2006 and 2011, PSE’s growth in approved non-production expense levels[[4]](#footnote-5) (on a per customer basis) was 3.8 percent on a combined basis (4.7 percent for electric and 2.2 percent for gas)[[5]](#footnote-6). PSE’s actual non-production O&M expenses in total were growing at an even faster rate (5.4 percent) during that period. Therefore, no matter which way you look at it, both the 1.2 percent growth in cost per customer and the 2.0 percent growth in total costs reported in Table 1 of my prefiled direct testimony compare favorably to PSE’s historical trend.

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

Q. Mr. Brosch refers to PSE’s proposed increase in base rates of 7.3 percent for electric and 5.2 percent for gas operations to suggest that there has not been an improvement in overall cost structure.[[8]](#footnote-9) Do you agree?

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

Q. How do you respond to Mr. Brosch’s criticism that PSE did not propose a Multi-Year Rate Plan or develop a K-Factor or attrition adjustment in its direct case?[[9]](#footnote-10)

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

# IV. UNCONTESTED ELECTRIC ADJUSTMENTS BETWEEN PSE AND PARTIES

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

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

**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) |  |
| 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 |

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

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

## A. Tax Benefit of Proforma Interest, Adjustments KJB-20.05 and SEF-15.05

Parties do not contest the manner in which the tax benefit of interest is calculated. However, rate base is a factor in determining the tax benefit of interest. Therefore, the total amount of this adjustment will differ between PSE and other parties where there are differences associated with rate base items.

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

PSE has accepted the proposals of Commission Staff and Public Counsel to lengthen the Payment Processing Deferral from one year to three years.[[10]](#footnote-11) ICNU and NWIGU have indicated they are neutral related to this adjustment.[[11]](#footnote-12) Therefore, this adjustment is no longer contested and the change to net operating income for this adjustment is a decrease of $2,010,221 for electric and $1,449,117 for natural gas operations.

## C. Montana Electric Energy Tax, Adjustment KJB-21.02

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

## D. Changes by PSE in Supplemental Testimony Ignored by ICNU

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

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

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

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

KJB-13.05 Tax Benefit of Proforma Interest (remains uncontested)

KJB-13.08 Bad Debt Expense (remains uncontested)

KJB-13.09 Incentive Pay (remains uncontested)

KJB-13.11 Interest on Customer Deposits (remains uncontested)

KJB-13.16 Wage Increase (remains uncontested)

KJB-13.17 Investment Plan (remains uncontested)

KJB-14.01 Power Costs

KJB-14.02 Montana Electric Energy Tax (remains uncontested)

KJB-14.05 Storm Damage

KJB-14.11 White River

KJB-14.13 Production Adjustment

I have indicated above which of these adjustments are uncontested in this proceeding. For the remaining adjustments indicated, no party provided testimony contesting these adjustments, including Mr. Mullins for ICNU and NWIGU. Absent testimony directly contesting these adjustments, PSE must assume that it was an oversight on the part of Mr. Mullins. Therefore, any differences in the proposed revenue requirement between PSE and ICNU and NWIGU resulting from these adjustments should be rejected and PSE’s adjustment should be approved.

# V. CONTESTED ELECTRIC AND CERTAIN COMMON ADJUSTMENTS

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

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

## A. Temperature Normalization, Adjustment KJB-20.01

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

A. Commission Staff recommends this adjustment be calculated using the schedule level weather normalization.[[12]](#footnote-13) Please see the Rebuttal Testimony of Dr. Chun K. Chang, Exhibit CKC-3T, for the reasons why the Commission should disregard Commission Staff’s recommendation and accept PSE’s adjustment as proposed. This adjustment has not been changed since PSE’s supplemental filing and increases electric net operating income by $17,527,344.

## B. Depreciation Study, Adjustment KJB-20.06

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

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

Q. Does PSE agree with Mr. McGuire’s assessment and proposed treatment of the alleged imbalance?

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

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

A. In PSE’s 2007 general rate case, PSE filed a depreciation study that proposed a 44-year service life for Colstrip Unit 1 and a 45-year service life for Colstrip Unit 2.[[15]](#footnote-16) Prior to that study, the service life for Colstrip was 40 years.

In response testimony in the 2007 general rate case, Public Counsel recommended a 60-year service life for all Colstrip units, which would result in retirement in 2035 for Colstrip Units 1 and 2.[[16]](#footnote-17) Similarly, Commission Staff witness William Weinman testified that although he generally agreed with the remaining life and life span concepts used by PSE’s depreciation expert to determine depreciation rates for production plant as well as the net salvage estimates, he likewise proposed a 60-year plant life for the Colstrip units.[[17]](#footnote-18)

In rebuttal, PSE continued to support a 45-year service life for the Colstrip units. PSE witness Michael Jones testified that compliance with environmental laws and regulations, such as the Clean Air Act, EPA’s Clean Air Visibility Rule, and Montana’s Mercury Emission Control Rule, may affect the useful life of coal-fired units such as Colstrip.[[18]](#footnote-19)

After rebuttal testimony was filed, PSE and parties to the proceeding entered into several settlement agreements addressing various issues raised in the general rate case. As one piece of this compromise, the parties agreed to extend the depreciable lives of the Colstrip units to 60 years, as proposed by Commission Staff and Public Counsel.[[19]](#footnote-20) It is the extension of the depreciable lives for Colstrip Units 1 and 2 to 2035 that has created the claimed imbalance that Mr. McGuire tries to correct.

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

A. No. It is duplicitous for Commission Staff to argue for a longer depreciation schedule in the 2007 general rate case (presumably to lower rates for customers) and now seek to punish PSE for agreeing in settlement to the proposal made by Commission Staff and Public Counsel. It also would be poor public policy for the Commission to allow such behavior, which will have a chilling effect on settlement efforts now and in the future.

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

A. Yes. It appears that Public Counsel recognizes the need to recover the undepreciated plant over the remaining life of Colstrip Units 1 and 2.[[20]](#footnote-21) Although Public Counsel’s proposed depreciation study has numerous flaws, as identified in the Prefiled Rebuttal Testimony of Mr. John J. Spanos, Exhibit JJS-4T, Public Counsel accepts PSE’s proposed depreciable life for Colstrip Units 1 and 2 and appropriately does not include a write-down of the assets.

Q. Does PSE agree with Sierra Club’s statement that PSE should bear some of the costs associated with its “poor planning” for the shutdown of Colstrip Units 1 and 2?[[21]](#footnote-22)

A. No. As previously stated, PSE proposed to set depreciation rates at a level that is consistent with the actual planned closing of Colstrip Units 1 and 2 in the 2007 general rate case, but PSE’s proposed depreciation rates were opposed by Commission Staff and Public Counsel who sought to keep rates lower for customers by extending the service lives of the facilities. PSE’s decision to enter into a broad settlement of multiple issues in the 2007 case, which included agreeing to the 60-year depreciation life proposed by Commission Staff and Public Counsel, should not be characterized as “poor planning,” and PSE should not be punished for its decision to compromise on a contested issue.

Further, Sierra Club acknowledges that, although PSE witness Michael Jones testified accurately about the environmental pressures the Colstrip units were likely to face in the years ahead, he “could not have anticipated the other economic factors that have compounded the economic distress for coal plants in the decade since the 2007 rate case.”[[22]](#footnote-23) Thus, this is not a case of “poor planning” on the part of PSE.

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

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

Q. Does PSE agree that Mr. McGuire’s Exhibit CRM-3 is “correcting” the depreciation reserve balance?[[23]](#footnote-24)

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

Q. Mr. McGuire suggests that his approach of “correcting the plant in service value for Colstrip Units 1 and 2” better adheres to the principles of “fairness and balance.”[[24]](#footnote-25) Does PSE agree?

A. No. Mr. McGuire’s proposal assumes that it is unfair to have current customers pay the unrecovered balance of Colstrip Units 1 and 2, but the majority of these customers received the benefit of lower rates resulting from the longer depreciation schedule over the past nine years. As addressed in the Prefiled Rebuttal Testimony of Mr. John J. Spanos, Exhibit JJS-4T, it is more appropriate for customers to pay modestly more for the service associated with these assets than to require future customers to pay for assets from which they receive no benefit.

Further, under Mr. McGuire’s proposal, PSE will not recover the “$127 million of reserve imbalance” for thirteen additional years beyond the life of Colstrip Units 1 and 2. Additionally, Mr. McGuire proposes the use of a regulatory asset but neither includes that asset in rate base nor allows PSE to recover any carrying charges. This proposal does not meet the principles of “fairness and balance” that Mr. McGuire purports to follow. Essentially, Mr. McGuire proposes customers receive an interest free loan for twelve years and PSE receives no compensation for the additional delay in recovery.[[25]](#footnote-26) This seems particularly punitive to PSE when Mr. McGuire recognizes that the existing rates were not wrong based on the information known at the time and, in fact, were extended based on Commission Staff’s proposal.[[26]](#footnote-27)

It is unclear why PSE’s investors should be punished by extended recovery further into the future with no carrying costs or inclusion in rate base. It is also surprising that Mr. McGuire chooses to remove the investment now, while the units are still in service and providing customers benefits. If the regulatory asset as proposed by Mr. McGuire were included in rate base, at least PSE would have the opportunity to earn a return on the investment. Mr. McGuire’s approach would require PSE to take a further write down as discussed in the Prefiled Rebuttal Testimony of Mr. Daniel A. Doyle, Exhibit DAD-7T.

Q. Mr. McGuire supports his proposal because of the “sudden decline in service value” due to the decision to close Colstrip Units 1 and 2 “early.”[[27]](#footnote-28) Does PSE agree?

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

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

A. No. As explained in the Prefiled Rebuttal Testimony of Mr. Matthew R. Marcelia, Exhibit MRM-1T, the abandonment accounting entries were recorded for Generally Accepted Accounting Principles (“GAAP”) purposes only. From a regulatory accounting standpoint, these entries *did not* impact plant in service because they were directly offsetting and all booked to FERC Account 101.[[28]](#footnote-29) Mr. Marcelia explains in detail why Mr. McGuire’s assumption is erroneous.

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

A. No. Mr. McGuire references RCW 80.04.250(2),[[29]](#footnote-30) which provides the Commission the power to make revaluations of the property of any public service company from time to time. However, neither case he cites that refer to this statute are relevant to Colstrip. In the 1927 case to which Mr. McGuire referred,[[30]](#footnote-31) although the Supreme Court recognized the statute allows for revaluation based on changing condition, the Supreme Court also recognized that particular statute did not apply in that case as can be seen by reading a little further in Mr. McGuire’s citation which provides that “the question under what conditions the necessity may arise is not presented here and we do not decide it.”[[31]](#footnote-32) There is only *one* instance in which the Commission required an adjustment to correct a reserve imbalance and that was in Docket U-86-02, in which depreciation expense had been booked inconsistently with GAAP.[[32]](#footnote-33) In that case, Pacific Power & Light had accrued accumulated depreciation only based on what it was collecting in rates rather than utilizing the approved depreciation rates; this created the inconsistency with GAAP. In contrast to the Pacific Power & Light case, PSE booked its depreciation expense consistent with the depreciation rates approved by the Commission in 2008, and Mr. McGuire does not provide any evidence to the contrary.

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

A. Mr. Mullins proposes leaving the current depreciation rates for Colstrip Units 1 and 2 in place and, at the end of the life, converting the remaining balance into a regulatory asset that would be recovered through a separate surcharge,[[33]](#footnote-34) which is actually a tracker. Mr. Spanos and Mr. Marcelia address why Mr. Mullins approach is not reasonable.

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

A. Similar to Mr. McGuire and others, Mr. Mullins has incorrectly assumed that the 2022 retirement date represents an early retirement. Therefore, he applies an approach similar to that used by the Oregon Public Utility Commission when addressing the early closure of the Trojan Nuclear Facility. Mr. Mullins recommends that the Commission follow a similar approach and allow for the stranded costs to be recovered through a regulatory asset that would be collected separately through a tracker and would accrue carrying costs based on long-term cost of debt rather than PSE’s full rate of return once Colstrip Units 1 and 2 are no longer in service.

Q. Does Sierra Club make a similar argument?

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

*While Unit 3 did operate for 13 years*, it will never operate again and can no longer be considered “useful” utility plant. Unit 3 was *entered into rate base under the assumption that it would serve customers for 30 years*. Shareholders were entitled to a return and ratepayers were liable for the full ownership cost as long as Unit 3 operated as expected.[[34]](#footnote-35)

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

A. No. There are some notable differences between the two facilities and their assumed life spans. Mr. Mullins claims that the Trojan Nuclear Facility shutdown is “probably the best example of an early retirement of a generation plant.”[[35]](#footnote-36) He provides the history of the Trojan plant, relying on the fact that the Trojan facility closed seventeen years earlier than originally anticipated. What Mr. Mullins and Dr. Hausman fail to recognize is that Colstrip Units 1 and 2, whether they close tomorrow or close as anticipated in mid-2022, will have been in service for longer than originally anticipated when the plants were placed in service. As discussed in the Prefiled Rebuttal Testimony of Mr. Ronald J. Roberts, Exhibit RJR-30T, the original anticipated life of Colstrip Units 1 and 2 was 25-30 years. As discussed earlier in my testimony, the “early shut down” referenced by the other parties is based solely on the 2007 settlement that actually extended the depreciable life of the plant to 60 years compared to the previously approved depreciable life. Colstrip Units 1 and 2 will have been in operation for over 40 years at the time the new depreciation rates take effect in 2018 and by the retirement date in 2022 will have been in service for more than 45 years. This is not comparable to either

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

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

Q. Mr. Mullins also provides an example about Deer Creek Mine and believes it is similar to Colstrip Units 1 and 2. Does PSE agree?[[36]](#footnote-37)

A. No. The Deer Creek Mine involved a sale of mining facilities. Therefore, the Deer Creek Mine example is more comparable to PSE’s sale of the Electron Hydro project in that there were unrecovered costs for those facilities after application of sale proceeds. In Electron, PSE had unrecovered costs, and the Commission allowed recovery of the regulatory asset over a four-year period.[[37]](#footnote-38) Similar to other regulatory assets, the Electron regulatory asset did not include direct carrying charges but is included in PSE’s rate base for ratemaking purposes.

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

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

Q. Is Mr. Mullins’ proposal to include those costs in a separate tracker necessary?

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

Q. How do you respond to Mr. Mullins’ proposal to require that any capital expenditures to plant aside from those included in the test year be included in the separate tracker with a prudency determination required for every asset?[[38]](#footnote-39)

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

Q. What is Sierra Club’s position regarding the appropriate depreciation rates for the Colstrip assets?

A. Sierra Club witness Dr. Ezra D. Hausman, Ph.D. has neither prepared a revenue requirement analysis nor proposed a specific adjustment to PSE’s revenue requirement calculations. Therefore, it is unclear what Sierra Club specifically proposes regarding Colstrip Units 1 and 2. Despite the lack of clarity regarding Sierra Club’s proposal for Colstrip Units 1 and 2, it is clear they are advocating for a shorter life for Colstrip Units 3 and 4. If the life for Colstrip Units 3 and 4 were shortened to 2025, as suggested by Sierra Club, the impact to revenue requirement would be approximately $16 million.[[39]](#footnote-40)

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

A. Dr. Hausman neither questions the proposed depreciation life for Colstrip Units 1 and 2 nor challenges PSE’s proposed depreciation study adjustment directly. However, Dr. Hausman’s reference to the GAAP regulatory asset and the “$176.8 million undepreciated balance”[[40]](#footnote-41) implies that there would be no change to the depreciation rates for Colstrip Units 1 and 2. As discussed in the Prefiled Rebuttal Testimony of Matthew R. Marcelia, Exhibit MRM-1T,[[41]](#footnote-42) the $176 million GAAP entry to which Mr. Hausman refers is based on the assumption that the depreciation rates for Colstrip Units 1 and 2 do not change from the current level. It is unclear if Mr. Hausman is making such a proposal, however, it seems disingenuous to advocate for a shorter life for Colstrip Units 3 and 4 and recognize the revenue requirement impact of such a change while ignoring the requested change in depreciation lives for Colstrip Units 1 and 2.

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

A. No. It is unlikely that Colstrip Units 1 and 2 will be completely depreciated by the closure date of July 1, 2022, even if the Commission were to adopt PSE’s proposed depreciation rates. However, the net book value at that time will certainly be much lower than under Commission Staff’s, ICNU’s and possibly Sierra Club’s proposals. As addressed in my prefiled direct testimony, the removal of the negative salvage associated with Colstrip Units 1 and 2 from the proposed depreciation rates[[42]](#footnote-43) ignores any interim salvage that may be necessary. Additionally, since the proposed depreciation rates will not take effect until the conclusion of this case, there will be differences because of the additional year of depreciation at the lower rate during the pendency of this proceeding. I address this now, not because I believe the proposed depreciation rates are incorrect, but merely to recognize that depreciation studies are an approximation and there will always be differences at the end of an asset’s life. The goal is to be close, but they will never be perfect. This is why PSE proposes to use the PTCs and hydro-related Treasury Grants to address the unrecovered plant and decommissioning and remediation of Colstrip Units 1 and 2.

Q. Sierra Club advocates that the regulatory liabilities should not be utilized to address undepreciated plant for Colstrip Units 1 and 2.[[43]](#footnote-44) Does PSE agree?

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

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

A. No. Only the Sierra Club has challenged the proposed depreciable life for Colstrip Units 3 and 4.**[[44]](#footnote-45)**

Q. Does PSE agree with Sierra Club’s recommendation?

A. Not entirely. As discussed in the Prefiled Rebuttal Testimony of Mr. Ronald J. Roberts, Exhibit RJR-30T, it may not be reasonable to retire Colstrip Units 3 and 4 by 2025 based on current information. However, there certainly are a number of issues that, as they continue to evolve, could impact Colstrip for depreciation study purposes. For example, the Oregon law to which Sierra Club refers[[45]](#footnote-46) requires Oregon utilities to have no coal in their portfolio by 2030. Two of the five co-owners of Colstrip Units 3 and 4 provide electric service in Oregon, and PSE does not know if, or how, the Oregon law could affect the operations of these co-owners. It is possible that the Oregon law could result in a shorter life for Colstrip Units 3 and 4 than currently reflected in the proposed depreciation study. Additionally, other unknowns, such as the impact of a carbon tax at either the federal or the state level (in Montana or Washington) and the continuation of low gas prices could likely affect the economics of Colstrip Units 3 and 4 for all owners and could lead to an earlier retirement as well.

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

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

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

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

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

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

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

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

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

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

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

A. Mr. Power’s testimony includes technical errors and broad generalizations that cloud an already complicated issue, although in the end he does not oppose PSE’s proposed use of hydro-related Treasury Grants or Production Tax Credits to address unrecovered costs associated with Colstrip Units 1 and 2.[[46]](#footnote-47) Mr. Power claims that PSE has proposed to “zero out the Colstrip 1 and 2 depreciation account”[[47]](#footnote-48); he insinuates that PSE’s existing depreciation rates did not include any costs for decommissioning and remediation[[48]](#footnote-49) all to reach his conclusion that it was a “lack of planning and preparation” that has created the situation with Colstrip Units 1 and 2 and that these lessons should be instructive for Colstrip Units 3 and 4.[[49]](#footnote-50)

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

A. Mr. Power has misquoted my testimony where I refer to removing the negative net salvage amount from the depreciation rates and instead he claims the proposed depreciation rate for the Colstrip Units 1 and 2 are zero; this is simply not true. Additionally, he claims that the existing depreciation rates included zero costs for decommissioning and remediation, which is also untrue. Mr. Power has managed to gloss over the fact that current depreciation rates were collecting some level of net salvage, albeit clearly too little in light of the changing regulations associated with the Coal Combustion Residuals (“CCR”) rules. He is correct that PSE did recognize some level of pond remediation would be necessary as reflected in the Asset Retirement Obligation (“ARO”) discussion; however, the CCR rules became law in 2015, which changed the landscape and resulted in far more prescriptive rules as addressed in the Prefiled Direct Testimony of Mr. Ronald J. Roberts, Exhibit RJR-1CT. To utilize these changing circumstances to imply it was poor planning is not an accurate assessment of the situation surrounding the Colstrip units.

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

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

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

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

Q. Please describe PSE’s concerns with Mr. Smith’s Schedule C-12?

A. According to Mr. Smith’s testimony,[[50]](#footnote-51) his depreciation adjustment is based on the new depreciation rates being recommended by Ms. McCullar; however, Mr. Smith’s work papers and the amounts included in his proposed revenue requirement do not appear to support that statement. For example, Ms. McCullar’s testimony states that she has accepted Mr. Spanos’ proposed depreciation rates for common equipment;[[51]](#footnote-52) therefore, one would expect Mr. Smith’s adjustment to be the same as that proposed by PSE. However, that is not the case when reviewing his Schedule C-12 because he removes $3,353,841 ($2,253,110 for electric and $1,100,730 for gas) of test period depreciation expense without any explanation in his testimony. Based on Public Counsel’s Response to PSE Data Request No. 12,[[52]](#footnote-53) it appears that Mr. Smith does not understand that the depreciation adjustment performed by PSE is a *restating* adjustment not a *pro forma* adjustment. PSE’s depreciation adjustment *restates* the actual test period depreciation expense as if the new rates had been in place as opposed to a *pro forma* adjustment that would apply the new depreciation rates to the September 30, 2016, end of period plant balances.

Mr. Smith’s adjustment to common, which he did not discuss in testimony or explain in his work papers, removes the test period depreciation expense associated with only a portion of the common FERC Account 397, Communication Equipment, on the basis that since that portion of the account is fully amortized there will not be amortization (depreciation) expense in the rate year, rather than leaving the test year amount unchanged. By doing so, he has chosen to pro form one single FERC account (and only a portion of FERC Account 397) to recognize that in 2018 those particular assets will no longer have amortization expense. However, by doing this he has ignored the other portion of the account where the test year included only a partial year of amortization expense. This can be seen by reviewing the total amortization expense for Common FERC Account 397 resulting from Mr. Smith’s adjustment. His adjustment only reflects 0.77 percent[[53]](#footnote-54) for FERC Account 397 rather than the 6.67 percent proposed in the depreciation study.

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

## C. Rate Case Expenses, Adjustment KJB-20.12

Q. Does your testimony respond to Commission Staff’s adjustment of rate case expenses?

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

## D. Pension Plan Expense, Adjustment KJB-20.15

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

A. Mr. Ralph C. Smith, witness for Public Counsel, disagrees with PSE’s long held regulatory treatment of using a four-year average of cash contributions for setting rates. He believes a more fully developed record exists in the current proceeding to support his contention that a four-year average of PSE’s pension expense, reported as required by the Financial Accounting Standards Board (“FASB”) under Accounting Standard Codification 715 Compensation – Retirement Benefits, formerly FAS 87, should be used.[[54]](#footnote-55) Because other parties refer to pension expense as FAS 87, I will do the same to avoid confusion.

Mr. Bradley G. Mullins, witness for ICNU and NWIGU, refers to the final Order in PSE’s 2009 general rate case and incorrectly states that the Commission required PSE to “use four years of expense, rather than four years of contributions.”[[55]](#footnote-56) Mr. Mullins proposes PSE use the *expected* 2017 pension expense noted in PSE’s Form 10-K filing for calendar year 2016.

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

A. No. FAS 87 is a GAAP requirement established to provide guidance in reporting net periodic pension costs for financial accounting reporting purposes. Computations used to report FAS 87 are performed by actuaries using assumptions regarding current and future demographics, life expectancy, investment returns, levels of contributions or taxation, and payouts to beneficiaries, among other variables. Each of these measures is based on estimates and are not actually known until a payout is made to the beneficiary, which could be decades away. Most notably, the discount rate applied in calculating pension interest expense and the expected return rate applied to the plan assets are major components of the pension expense required to be reported by companies under FAS 87, yet these rates have been a point of debate and federal policy changes throughout the last three decades.

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

A. No. Very similar to PSE’s regulatory treatment of ASC 815 Derivative and Hedging (formerly FAS 133) transactions, expenses born out of adhering to a unified accounting code for GAAP purposes is not necessarily representative of costs that should be included for ratemaking purposes. Just as PSE eliminates the impact of FAS 133[[56]](#footnote-57) in rate setting, it should also continue to remove the expenses associated with FAS 87 and base its pension expense on actual contributions. Even Mr. Smith recognizes that FAS 87 does not dictate a particular ratemaking treatment.[[57]](#footnote-58)

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

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

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

A. Although quarterly cash contributions are based upon PSE’s review of the same plan asset and Projected Benefit Obligation balances used to record FAS 87 pension expenses,[[58]](#footnote-59) there is an important difference—cash paid by PSE goes directly to the pension trust, and, once paid, it can never be taken back. The contributions represent actual dollars coming out of PSE’s cash account that are paid into the Pension Trust where they will reside permanently in the trust until a participant begins receiving his or her benefits. PSE believes the contribution approach aligns closely with this Commission’s position on the relevance of cash versus accrual accounting in rate setting. The recent authorization of PSE’s property tax tracker ordered by the Commission in its Expedited Rate Filing (“ERF”) in Dockets UE-130137 and UG-130138 is an example of the Commission’s preference for known and measurable amounts. In that case, the Commission agreed that rather than using accounting estimates of property tax expense for rate setting purposes, it was more appropriate to set rates in a tracker based on the known and measurable cash payments made by PSE.

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

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

Mr. Smith’s only support for making the change from normalized cash contributions to FAS 87 is his belief that using the normalized contributions “would significantly overstate the 2018 rate year pension expense,”[[59]](#footnote-60) but only in relation to FAS 87 expense for which he provides no substantive evidence proving it is the more appropriate measure for ratemaking. His support relies on the 2016 actuarial study to reach his conclusion that *estimated future* contributions will be less than the 2013 to 2016 four-year average of *actual* contributions paid by PSE. He also points to the “fact” that his “recommended use of a four-year average of net periodic pension cost is generally in line with the Company’s projected cash contributions”[[60]](#footnote-61) when he looks at the projected 2017 through 2025 period. None of these reasons support why FAS 87 expense is a more appropriate metric to use for rate setting purposes other than it provides a lower level of expense. [[61]](#footnote-62) Mr. Smith merely concludes that PSE’s projected pension contributions are higher than its projected FAS 87 expense and, therefore, moving to the FAS 87 expense should be accepted.

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

A. No. Perhaps one of the strongest arguments for continuing to use actual cash contributions in setting rates is the existence of the natural checks and balances occurring in today’s heavily scrutinized pension environment. PSE’s management must continually maintain a balance to comply with strict guidelines set forth by the Pension Benefit Guaranty Corporation to manage or avoid costly premiums, while justifying cash outlays to its board of directors. Mr. Smith’s testimony alludes to management’s discretion in how much to contribute each year,[[62]](#footnote-63) however, PSE is never incentivized to be either overfunded or underfunded in its pension plan and Mr. Smith has not provided any documentation to suggest otherwise. Therefore, using normalized actual cash contributions is not unreasonable and does not incentivize PSE to over-contribute.

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

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

Q. Why would PSE avoid being excessively *over*funded?

A. PSE does not have unlimited cash flow and carefully manages its pension contributions based on its Retirement Funding Guidelines and applicable pension enactments so that it can optimize its available cash to fund operating activities. Once funds are contributed to the pension plan, they may not be removed. Therefore, PSE has no incentive to excessively fund the pension plan, and Mr. Smith has not provided any support to demonstrate otherwise.

Q. How have PSE’s pension obligations compared to PSE’s plan assets?

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

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

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

Q. Why does Mr. Mullins refer to Docket UE-140762 in claiming that the Commission has been moving away from historical contributions?[[63]](#footnote-64)

A. Mr. Mullins provides no support for why Docket UE-140762 involving PacifiCorp is relevant in determining whether FAS 87 or cash contributions is the appropriate ratemaking treatment of PSE’s pension expense. The Public Counsel witness to whom Mr. Mullins refers addressed the issue of whether the pre- or post-test year pension actuarial report should be used for the FAS 87 expense to be included in the revenue requirement, not whether cash contributions or FAS 87 expense is appropriate for ratemaking purposes. In fact, Mr. Mullins’ testimony documents that the use of average contributions over a four year period has been in place for PSE “at least as far back as Docket UE-920433.”[[64]](#footnote-65)

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

Q. Mr. Mullins advocates using an estimated amount of FAS 87 expense for a single year, for setting rates.[[65]](#footnote-66) Does PSE agree with this approach?

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

Q. Please summarize PSE’s recommendation.

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

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

## E. Environmental Remediation, Adjustment KJB-20.19

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

A. No. Ms. Susan Free discusses the difference in the position of PSE and other parties for the environmental remediation adjustment, Adjustment KJB-20.19.[[66]](#footnote-67)

## F. Working Capital, Adjustment KJB-20.23

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

A. No. Ms. Susan Free discusses the difference in the position of PSE, and Commission Staff for the working capital adjustment, Adjustment KJB-20.23.[[67]](#footnote-68)

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

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

A. The Prefiled Rebuttal Testimony of Paul K. Wetherbee, Exhibit PKW-15CT, describes the differences between PSE’s power costs and the power costs proposed by Commission Staff and ICNU witnesses. The Prefiled Rebuttal Testimony of Ronald J. Roberts, Exhibit RJR-30T, addresses (i) PSE’s concession of Commission Staff’s proposal to reduce PSE’s rate year costs for its licensing activities relating to Snoqualmie and Baker Hydroelectric projects to reflect test year levels and (ii) updates for major maintenance on Colstrip Units 1 and 2.

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

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

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

A. Yes. As a result of PSE’s acceptance of Commission Staff witness Jing Liu’s recommendation to remove the fixed cost production factor,[[68]](#footnote-69) as I discuss later, adjustments which are defined as fixed production costs[[69]](#footnote-70) and that are being requested for inclusion in the decoupling mechanism no longer have the fixed production factor applied. This results in the costs included in the revenue requirement being 2.535 percent higher than if the production factor had been applied. This change is being made as these costs would no longer be subject to growth in customers between the test year and the rate year.

Overall, including the changes for (i) removing the fixed production factor, (ii) the update for increased OATT revenues, and (iii) the changes discussed by Mr. Paul Wetherbee and Mr. Roberts in their rebuttal testimonies, the impact on net operating income for this adjustment is now a decrease of $682,861 compared to the $14,772,510 decrease included in the supplemental filing.

## H. Storm, Adjustment KJB-21.05

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

A. Commission Staff witness Schooley proposes that the Commission rescind the storm deferral mechanism, and he prepares his storm damage adjustment retroactively, assuming that his methodology was approved by the Commission in the 2011 general rate case.[[70]](#footnote-71) Kroger Witness Higgins recommends that the remaining costs associated with the 2006 storm event, frequently referred to as the “Hanukkah Eve” storm, be moved to a separate rider and recommends that the post-test year qualifying events only be included in rates if they are above the $10.6 million included in “normal rates.”[[71]](#footnote-72) Public Counsel witness Smith proposes that the 2012 storm event, frequently referred to as “Snowmageddon” event, be amortized over a ten-year period similar to the Hanukkah Eve storm.[[72]](#footnote-73)

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

A. Commission Staff is utilizing recycled arguments that the Commission has rejected, as recently as PSE’s last general rate case, to eliminate the storm deferral mechanism that has worked well and benefited both customers and PSE for more than a decade. Not only does Commission Staff’s proposal eliminate the existing storm deferral mechanism on a going forward basis, the adjustment as proposed by Mr. Schooley attempts to retroactively implement his proposal by disallowing recovery of the more than $60 million of previously deferred storm costs that were properly deferred under the existing mechanism. The Commission should reject Commission Staff’s proposal, allow the storm deferral mechanism to continue, and approve the proposed amortization of the costs associated with the 2012 through 2017 qualifying events as reflected in Adjustment KJB-21.05.

Q. Can you provide a brief history of PSE’s storm deferral mechanism?

A. Prior to Docket UE-921262 storm damage was recovered using an accounting reserve in a manner similar to insurance. All storm damage was deferred by charging a reserve and the amount allowed in rates was credited to that reserve and charged to storm damage expense. In Docket UE-921262, Commission Staff[[73]](#footnote-74) proposed normalizing storm damage costs over a six-year period, and that extraordinary property damage be amortized over a six-year period. In that docket, Commission Staff proposed to define “catastrophic event” as one affecting 25 percent or more of PSE’s customers, occurring infrequently, and affecting a wide geographic area. Mr. Schooley’s proposal in that case was approved by the Commission and that definition of catastrophic storm was used until 2004. In Docket UE-040641, in response to PSE’s proposal to define a qualifying event as greater than $2 million, Commission Staff witnesses Mr. Douglas E. Kilpatrick and Mr. James M. Russell proposed the current methodology of using the Institute of Electrical and Electronic Engineers (IEEE) standard 1366-2003 using the 2.5 Beta Methodology, modified to shorten the duration of a sustained interruption from five minutes to one minute (“IEEE Standard” or “2.5 Beta Method”) to define a “major event” and including a threshold of “normal” storm costs to replace the “catastrophic event” standard of 25% of customers without power previously approved by the Commission. PSE did not object to using the IEEE standard as a trigger for deferring storm damage, and the Commission approved the current definition for qualifying storms using the IEEE Standard. This definition and benefits associated with using the IEEE Standard is explained in more detail in the Prefiled Rebuttal Testimony of Catherine A. Koch, Exh. CAK-4T.

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

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

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

A. No. PSE is not allowed to defer any costs for storms that do not meet the IEEE major event standard approved in Docket UE-040641. These normal storm costs are part of the normalization calculation which uses a six-year average. As discussed by Mr. Kilpatrick in Docket UE-040641, the IEEE major event day concept is used to establish a threshold value for a company’s normal daily reliability as expressed in a daily value for SAIDI:

Any days with a daily SAIDI value greater than this threshold are considered as those days where the electrical system experienced above-normal stresses, such as during severe weather. The system’s performance during these major event days is evaluated separately from day-to-day operation so that measurement of the underlying reliability of the electric system is not overshadowed by these significant events.[[74]](#footnote-75)

Q. What storm costs are allowed to be deferred?

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

Q. Can you please summarize PSE’s cost treatment and deferral capabilities under its storm mechanism?

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

**Table 3. Types of Storm Expense and Treatment**



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

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 events that have been deferred since the last case as well as removing the deferrals from the working capital calculation.[[75]](#footnote-76)

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

A. Mr. Schooley’s entire premise for “un-deferring” the 2012 through 2017[[76]](#footnote-77) events, except for the Snowmageddon storm, is that, in his view, these events were not truly “catastrophic” events.[[77]](#footnote-78) He believes that the IEEE threshold that the Commission authorized was too easily met and that the $8 million threshold before deferrals could begin was too low of a hurdle.[[78]](#footnote-79) In essence, he is asking the Commission to pretend that it accepted Commission Staff’s proposal in the 2011 general rate case by rejecting the amortization of the deferred storm costs reflected on lines 24 through 26b of Exhibit KJB-21.05.

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

A. No. Commission Staff implies that the deferred costs do not need to be recovered because they are included in the calculation of the six-year average that would be used to “set a reasonable level of ongoing cost recovery.”[[79]](#footnote-80) However Mr. Schooley’s adjustment to the six-year average merely addresses the average level of storm costs to be included in the rate year for inclusion in base rates, which would be necessary if the current storm deferral mechanism was to be eliminated on a going-forward basis. His adjustment has done nothing to address the costs that were deferred over the past six years consistent with PSE’s approved storm deferral mechanism—the mechanism that the Commission considered and approved continuation of in PSE’s last general rate case. Commission Staff is requesting that the Commission retroactively rescind its decision from the 2011 case by requiring PSE to “un-defer”‘ those expenses, which would result in a write-off of more than $60 million of prudently deferred qualifying event costs.

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

A. Yes. As mentioned earlier, Commission Staff proposed a similar elimination of the storm deferral mechanism in PSE’s last general rate case, which the Commission rejected. In rejecting Commission Staff’s proposal, the Commission authorized PSE to “retain the current Commission-approved mechanism for storm damage recovery.” [[80]](#footnote-81) However, Mr. Schooley’s testimony refers to “un-deferring” the costs associated with qualifying storm costs that occurred since PSE’s last general rate case. The only reason for “un-deferring” these costs would be if they were found imprudent or if PSE had inappropriately deferred them. That is clearly not the case. Commission Staff’s Response to PSE Data Request No. 09[[81]](#footnote-82) admits that Mr. Schooley neither questions the prudency of nor asserts that that PSE inappropriately deferred these storm costs. His testimony, which falsely indicates that the cost recovery of these deferred storms has been addressed by their inclusion in his calculated six-year average, seems disingenuous. This is especially evident when considering that he makes a restating adjustment to the test period Investor Supplied Working Capital to recognize the impact of the write-off should the Commission accept his proposal and not allow amortization of the deferred storm costs as of the end of the test year.

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

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

Under the storm deferral mechanism customers only pay for the qualifying events that actually occur above the $8 million annual threshold allowing for the range of “normal” costs included in the six-year average to be relatively consistent. Exhibit KJB-33 demonstrates this difference by comparing the six-year average normal storm costs reflected in Adjustment KJB-21.05 to that reflected on page 35 of Ms. Cheesman’s Exhibit MCC-2.[[82]](#footnote-83) In Commission Staff’s adjustment, the amount of normal storm damage expense that would be built into rates in this proceeding would be approximately $18.8 million, which is nearly double the $10.6 million included in the level of normal storms calculated in PSE’s adjustment.

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

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

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

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

A. No. During the 2006 through 2010 time period, there were 32 qualifying events, 11 qualifying events in 2006 alone.[[83]](#footnote-84) This compares to the 23 qualifying events during the 2011 through 2016 period to which Mr. Schooley refers. None of the years had as many events as 2006; however, both calendar 2014 and 2015 had seven qualifying events.

Q. Mr. Schooley states that the current mechanism is biased toward PSE,[[84]](#footnote-85) does PSE agree?

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

Q. Does PSE agree with Commission Staff that there are no substantive losses to changing the mechanism?[[85]](#footnote-86)

A. No. Commission Staff’s adjustment as proposed will result in PSE writing off more than $60 million of prudently incurred and deferred qualifying storm costs, which represents a $39.6 million decrease in after tax net income ($60.9 million × (1 – 0.35)). Considering that in her testimony, Ms. Cheesman views a change of one basis point of earnings to be material,[[86]](#footnote-87) a decrease of nearly 75 basis points[[87]](#footnote-88) is obviously substantial.

Commission Staff contends that with decoupling there is stable recovery of storm costs because the six-year average is part of the allowed revenue per customer and therefore PSE will recover its costs.[[88]](#footnote-89) Unfortunately, Commission Staff has missed the point that, under Commission Staff’s proposal (i) the only costs that will be recovered because of decoupling is the average costs and (ii) there is considerably more variability in the definition of “normal” costs, which harms customers by setting the average higher than it would otherwise need to be if the mechanism was left unchanged.

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

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

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

A. Not entirely. PSE can agree with Mr. Schooley’s calculation of the six-year average as $18.8 million, which is consistent with the figure reflected on line 11 of Exhibit MCC-2 Adjustment 13.09. However, any modification to the storm mechanism must be done on a prospective basis, and the deferred storm costs that were booked would need to be amortized as reflected in PSE’s adjustment. Any change that does not address the outstanding deferrals will result in a significant retroactive write-off of prudently incurred and deferred storm cost and is certainly unfair to PSE.

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

A. No. As discussed earlier, the adjustment to investor supplied working capital is directly related to Mr. Schooley’s proposal to “un-defer” previously recorded deferred storm costs balances. Additionally, his adjustment removes the September 30, 2016 end of period[[89]](#footnote-90) balance for the storms that he would “un-defer,” decreasing rather than utilizing the test year AMA balances that were included in the working capital calculation.

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

A. Yes. First, Commission Staff proposes that catastrophic storm deferrals begin amortizing in the month when the repair work is completed, claiming that the deferred costs are similar to plant costs which begin depreciating once placed in service.[[90]](#footnote-91) Commission Staff’s proposal would result in the amortization of the catastrophic storm costs before they were included in rates, which would typically occur in the next general rate case or possibly an expedited rate filing. His assumption that deferred storm costs are the same as the capitalized plant which is placed in service and begins depreciation is simply not true because the plant has a far longer life than the amortizations associated with storm costs. Storm costs have typically been amortized over a four-year period, and the longest amortization period used for storm costs has been the ten-year amortization used for the Hanukah Eve storm compared to the depreciation lives of 30 to 50 years for distribution and transmission assets. Thus, under Mr. Schooley’s proposal, PSE would not be able to recover much of the costs it incurs especially for the limited number of storms that would be catastrophic storms under his proposal, since they would be partially or fully amortized before they could be recovered in rates.

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

The final element to be addressed is Mr. Schooley’s proposal that the six-year average storm normalization adjustment be included in the Commission Basis Report or in the expedited rate filing process.[[91]](#footnote-92) PSE can agree that including the six-year average in an expedited rate filing or the Commission Basis Report would be appropriate, provided that this adjustment not be included for purposes of the earnings test.

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

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

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

The disparity would be even greater if the Commission were to make modifications to the existing storm deferral mechanism proposed by Commission Staff. Lines 4 and 5 reflect the 2015 normalization adjustment, under Commission Staff’s proposed approach in which no storms would have been deferred in calendar 2015, resulting in $35 million of actual storm expenses during that period. Through the normalization process, the actual expenses would be replaced with the six-year average, eliminating approximately $16 million of *actual* expenses incurred by PSE during the reporting period increasing the reported net operating income by $10.4 million, or a 20 basis point difference. The same would be true if actual storm expenses had only been $4.4 million, the lowest year in the six-year average. In a year when PSE would have significantly less actual storm expenses, PSE would replace the actual cost of $4.4 million, with additional expenses of $14.8 million through the normalization process eliminating $9.6 million of earnings, or 18 basis points, that would have otherwise been shared with customers. Commission Staff’s proposal adds $20 million of added after tax volatility to PSE’s earnings that Commission Staff proposes be ignored in the calculation of the earnings test.

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

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

A. Mr. Higgins recommends that the remaining costs from the Hanukkah Eve storm be moved to a separate rider and recommends that the post-test year events only be included in rates if they are above the $10.6 million included in “normal rates.”[[92]](#footnote-93)

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

A. No. It is unnecessary to move the remaining Hanukkah Eve storm deferral to a separate tracker. As demonstrated by the excess amortization that was tracked with the 2010 events, PSE would continue to recognize amortization expense against the Hanukkah Eve storm, which would result in a negative balance that could be used to offset future events. In the alternative, the excess amortization from the 2010 events could be used to offset the remaining Hanukkah Eve balance rather than offsetting the 2014 through 2016 events, as PSE has proposed in its initial filing. This would be a far simpler approach than creating a separate tracker for the remaining Hanukkah Eve balance.

Q. Mr. Higgins also proposes that the post-test year amounts only be allowed for amortization if they are above the six-year average being established in this case ($10.6 million).[[93]](#footnote-94) Does PSE agree with his proposal?

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

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

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

Q. Public Counsel witness Smith proposes a longer amortization of 2012 storm costs. Does PSE agree with his proposal?[[94]](#footnote-95)

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

Q. Please summarize PSE’s recommendation regarding the storm recovery mechanism and storm damage adjustment?

A. The summary of my recommendations is as follows:

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

2) Reject Commission Staff’s proposed storm damage adjustment, including the adjustment to investor supplied working capital;

3) Reject the modifications to storm deferral amortizations proposed by both Mr. Higgins and Mr. Smith; and

4) Approve PSE’s storm damage adjustment as presented in Adjustment KJB-21.05, which decreases net operating income by $8,389,018 and remains unchanged from the supplemental filing.

## I. Energy Imbalance Market, Adjustment KJB-21.08

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

A. Commission Staff witness Frankiewich does not contest the calculations of PSE’s EIM Adjustment or its prudency; however, he proposes that all costs associated with the EIM should not be included in either general rates or the PCA baseline rate, but should be included as a line item in the PCA so that benefits would be reflected in the PCA sharing bands.[[95]](#footnote-96)

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

A. Yes. Commission Staff’s proposal is inconsistent with the PCA settlement recently approved by the Commission.[[96]](#footnote-97) As discussed in the Prefiled Rebuttal Testimony of Mr. Paul K. Wetherbee, Exhibit PKW-15T, Commission Staff is proposing to modify the updated PCA mechanism that was just implemented eight months ago. As part of the PCA settlement in Docket UE-130617, the parties agreed to a five-year moratorium, which prohibited parties from advocating for changes to the PCA mechanism during that time period.[[97]](#footnote-98) Additionally, the settlement removed fixed costs from the PCA mechanism—a change for which Commission Staff had advocated. Now, less than a year after the PCA changes were implemented, Mr. Frankiewich proposes to change the PCA mechanism by including fixed costs in the PCA associated with PSE joining the EIM.[[98]](#footnote-99) Mr. Frankiewich’s proposal seems to stem completely from his misunderstanding of the relationship between general rates and the baseline rate used in the PCA mechanism.

Q. Does Mr. Frankiewich challenge either the prudency of joining the EIM or the capital costs and O&M included in PSE’s proposed adjustment?

A. No. In fact, Mr. Frankiewich makes it clear that he does not challenge the prudency of joining the EIM,[[99]](#footnote-100) the prudency of the costs,[[100]](#footnote-101) or the calculation of the adjustments.[[101]](#footnote-102)

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

A. Mr. Frankiewich claims that the pro forma adjustment places the burden of covering capital costs directly through general rates yet the EIM benefits will mostly accrue to PSE through the PCA mechanism.[[102]](#footnote-103) Mr. Frankiewich’s assessment quite frankly does not make sense since the overall impact on general rates is zero. The increased revenue requirement of $8.47 million associated with the incremental capital and O&M costs has been completely offset by the direct reduction to power costs for the estimated benefits of $8.47 million, included in Adjustment KJB-21.01.[[103]](#footnote-104) The costs and benefits entirely offset within the revenue requirement model; therefore, the impact on general rates in this proceeding is zero.

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

## J. White River, Adjustment KJB-21.11

Q. What is Commission Staff’s position with respect to the White River adjustment?

A. The only part of PSE’s adjustment that Commission Staff contests is the three-year amortization period PSE is requesting for the deferred unrecovered regulatory asset costs.[[104]](#footnote-105)

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

A.Commission Staff witness E. Cooper Wright claims the Commission approved the current amortization period in a previous order with the caveat “to continue amortizing these costs at the current depreciation rate until better information is known related to sales and salvage values associated with this property.”[[105]](#footnote-106) Mr. Wright also claims PSE has not shown any new information that would alter the Commission-established amortization rate.[[106]](#footnote-107) PSE believes this part of the order related to the status of the surplus properties, i.e., whether they could be sold, which was an outstanding item at the time the order was issued and continued to be an outstanding item until this rate case. PSE does not believe this section of the Commission order related to the length of the amortization period.

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

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

Q. Does PSE agree with Mr. Wright’s statement that PSE has not shown any new information that would alter the Commission-established amortization rate?[[107]](#footnote-108)

A. No. As discussed in the Prefiled Direct Testimony of Paul K. Wetherbee, Exh. PKW-1CT, “PSE has sold and has current or future needs for the remaining properties.”[[108]](#footnote-109) Mr. Wright’s testimony acknowledges Mr. Wetherbee’s statement with the following, “By the filing of this rate case, PSE had completed selling of the property intended to be sold to other parties.”[[109]](#footnote-110) Mr. Wright states that “Staff has reviewed the property transfers and has found them reasonable because each transfer meets the definition of each destination FERC account. The Company’s property transfers reflect good accounting practice.”[[110]](#footnote-111)

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

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

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

PSE also believes there is precedent for the three-year amortization period based on the amount of the regulatory asset compared to other amortizations approved in PSE’s 2009 and 2011 general rate cases in Dockets UE-090704 and UE-111048 respectively. In the 2009 case, the Commission approved PSE’s Wild Horse Expansion estimated annual amortization and net rate base amount for deferred costs associated with the wind project, which went into service November 9, 2009, until April 7, 2010 when the 2009 GRC rate year began. The balances of the deferred costs associated with the Wild Horse Expansion at the time the amortization was approved was $5.6 million. The Commission approved a two-year amortization period for this deferral.

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

Like the White River deferral, these two deferrals are related to deferred plant costs. The White River deferral balance and amortization period fall between each of these referenced deferrals; therefore, PSE’s request for a three-year amortization period for the White River deferral is appropriate, especially in consideration of the length of time PSE has held this regulatory asset. Accordingly, the Commission should approve PSE’s adjustment which has not changed since the supplemental filing.

## K. Hydro-Related Treasury Grants, Adjustment KJB-21.12

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

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

Q. Would you summarize the position of the parties on PSE’s proposal to repurpose the hydro-related Treasury Grants and PTC’s to address the decommissioning and remediation costs for Colstrip Units 1 and 2?[[111]](#footnote-112)

A.Yes. In general Sierra Club and Public Counsel support PSE’s proposal and Public Counsel has accepted PSE’s adjustment to address decommissioning and remediation at Colstrip Units 1 and 2. Commission Staff Witness Hancock supports the repurposing with some modification, and ICNU witness Mullins essentially rejects PSE’s proposal and has proposed a separate tracker that addresses only the unrecovered plant and the estimated decommissioning and remediation costs through 2029, then converts to a “pay as you go” scheme.[[112]](#footnote-113)

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

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

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

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

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

A. No. Mr. Mullins incorrectly states that both the hydro and Lower Snake River Treasury Grants are currently being passed back to customers through Schedule 95A.[[113]](#footnote-114) Mr. Mullins is correct that the Treasury Grants related to the Lower Snake River[[114]](#footnote-115) wind facility are being passed back to customers through Schedule 95A; however, he has incorrectly described the current treatment of the hydro-related Treasury Grants, which are currently included as a reduction or offset to PSE’s rate base.

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

A. The regulatory treatment of the hydro-related Treasury Grants was part of the settlement agreement in PSE’s 2013 Power Cost Only Rate Case (“PCORC”).[[115]](#footnote-116) In that case, parties agreed that rather than including the hydro-related Treasury Grants in Schedule 95A, these Treasury Grants would be treated in a manner equivalent to a reduction of rate base, and the grants were to be amortized over the remaining life of the plant assets. The fact that the hydro-related Treasury Grants are already reflected as a reduction to PSE’s rate base is one of the reasons PSE proposed to utilize them for the Colstrip Units 1 and 2 decommissioning and remediation. Additionally, use of the Treasury Grants and monetized PTCs as a rate base offset is consistent with the treatment of negative salvage is addressed when it is incorporated in depreciation rates. The only direct impact to customers from the repurposing of the regulatory liabilities is the discontinuation of the current amortization expense.

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

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

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

Q. Has PSE accepted Commission Staff’s proposal regarding the fixed production factor?

A. Yes. As discussed in the Prefiled Rebuttal Testimony of Mr. Jon A. Piliaris, Exhibit JAP-46CT, PSE accepts Commission Staff’s proposal to set fixed production costs at a fixed level rather than tie them to the number of customers, as long as this is paired with Commission Staff witness Ms. Jing Liu’s proposal to eliminate the production factoring of these costs in the determination of allowed revenue. ICNU has indicated they are neutral related to this adjustment.[[116]](#footnote-117)

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

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

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

A. No, although Public Counsel witness Smith indicates they have accepted PSE’s fixed production factor,[[117]](#footnote-118) another Public Counsel witness, Michael L. Brosch, advocates for “complete decoupling.”[[118]](#footnote-119) It would be inappropriate to include the production factor accepted by Mr. Smith, which reduces fixed production costs for the differences in customers between test year and rate year levels, and then deprive PSE of the opportunity to recover these costs at the rate year level determined as appropriate in the Commission’s final order. These two issues must be handled consistently. Either fixed production costs should be production factored based on customer growth and then allowed to grow with customers or they should not be production factored and held constant at rate year levels.

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

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

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

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

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

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

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

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

A. Mr. Brad G. Mullins for both ICNU and NWIGU recommends removal from rate base of all electric and gas balances of plant held for future use. Mr. Mullins states that PSE has not demonstrated that the properties are used and useful to ratepayers.[[119]](#footnote-120)

Q Does PSE agree with Mr. Mullins’ proposed adjustments?

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

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

A. Public Counsel witness Smith recommends removal of two properties that are currently part of plant held for future use.[[120]](#footnote-121) These were first placed in future use in 1992. Based on the Commission’s Order in Dockets UE-920433, UE-920499 and UE-921262 and the fact that these two properties have been in future use for more than 20 years, Mr. Smith recommends removing the properties shown below:



Q. Does PSE agree with Mr. Smith’s Adjustment?

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

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

Q. Please discuss ICNU’s adjustment with respect to net operating losses.

A. Mr. Mullins for ICNU and NWIGU has proposed a pro forma adjustment to eliminate the net operating losses currently included in PSE’s rate base calculation. Mr. Matthew Marcelia discusses the differences in the positions of PSE and ICNU for this adjustment.[[121]](#footnote-122)

## Q. Amortize PTCs, ICNU Adjustment IN-3

Q. Please discuss ICNU’s adjustment to amortize PTCs.

A. ICNU witness Mullins has proposed a pro forma adjustment to commence amortization on the PTCs that PSE has not yet utilized on its tax returns.[[122]](#footnote-123) Mr. Matthew Marcelia discusses the differences in the positions of PSE and ICNU for this adjustment. *See* Exhibit MRM-1T. There is further discussion later in my testimony regarding PTCs.

## R. Ardmore Substation Overruns, ICNU Adjustment IN-6

Q. Please discuss ICNU’s adjustment with respect to the Ardmore Substation.

A. ICNU witness Mullins has reduced the Ardmore Substation construction costs by $13.6 million based on his claim of cost overruns as compared to PSE’s $25.9 million budget.[[123]](#footnote-124)

Q. Does PSE agree with Mr. Mullins’ Adjustment to reduce the Ardmore Substation by $13.6 million?

A. No. PSE does not agree with Mr. Mullins adjustment to reduce the Ardmore Substation by $13.6 million. As described in the Prefiled Rebuttal Testimony of Catherine A. Koch, Exhibit CAK-4T, the project was constructed prudently and the ultimate costs are, in part, related to the expanded scope of the project, which included retiring the Interlaken Substation and combining it within the Ardmore Substation footprint. Mr. Mullins’ assertions are incorrect and his proposed adjustment should be rejected.

# VI. CHANGES BY PSE AT REBUTTAL

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

A. No. When PSE made its initial filing it recognized that a number of adjustments could require updating as better information became available over the course of the proceeding. The adjustments that originally contemplated updates that have not changed are the Property and Liability Insurance Adjustment KJB-20.14E and 15.14G, Employee Insurance Adjustment KJB-20.18E and 15.18G, South King Service Center Adjustment KJB-20.21 and 15.21G, Energy Imbalance Market Adjustment KJB-21.08[[124]](#footnote-125) and Mint Farm Adjustment KJB-21.10. All of these adjustments are uncontested as to their amounts and considering the materiality thresholds applied by Commission Staff, none of the updates originally anticipated by PSE are materially different from the adjustments included in PSE’s supplemental filing. Therefore, PSE has not proposed updates for these adjustments in this rebuttal filing.

# 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]](#footnote-126) 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.

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

A. As discussed earlier in section V. B. of my testimony, customers received the benefit of lower depreciation rates for all four Colstrip units during the 2009[[126]](#footnote-127) through 2017 period due to the extension of the assets depreciable life to 60 years. Additionally, this period is closely aligned with the period that the PTCs were generated, but due to ongoing net operating losses PSE has not been able to be utilize these PTCs on its tax return. The use of some of the monetized PTCs to address the undepreciated balance, is a reasonable approach.

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

A. Yes. Both NWEC and Sierra Club claim that better planning needs to occur for the eventual retirement of Colstrip Units 3 and 4 and that there are lessons to be learned from the change in circumstances with Colstrip Units 1 and 2.[[127]](#footnote-128) While I do not agree with their assessment that there was “poor planning” around the retirement of Colstrip Units 1 and 2, I do agree that planning for the uncertainty around the eventual retirement of the Colstrip Units 3 and 4 in order to minimize customer rate impacts is important. Retaining the PTCs once they have been monetized, in a separate retirement account that is a rate base offset is a way to achieve that “better planning” and will prevent any future intergenerational equities that could occur should circumstances change that further shorten the life of any of the Colstrip units. Additionally, as I discussed earlier, the rate base offset treatment is representative to how the negative salvage and accumulated depreciation reserve would be treated.

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

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

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

A. Yes, Mr. Hancock is correct that once placed in a retirement account established under RCW 80.84.020(2)(a) the funds may not be utilized for any purpose other than decommissioning and remediation costs associated with an eligible coal unit. However, this does not prevent the Commission from allowing the PTCs to be included in a retirement account, separate and apart from an account created pursuant to RCW 80.84.020(2), to be used to address any unrecovered plant balances associated with the Colstrip facilities.

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

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

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

A. No, the only difference is that a separate account would be established to track the PTCs once they were monetized. My direct testimony, envisioned that once the PTCs were utilized for tax purposes that instead of passing the funds back through a Schedule 95A rate change, PSE would credit the FERC 108 retirement account established for Colstrip Units 1 and 2.[[128]](#footnote-129) In light of the concerns identified by both Mr. Hancock and Mr. Mullins that once the funds are placed in the RCW 80.84.020(2)(a) retirement account they may not be redistributed until all remediation is completed,[[129]](#footnote-130) the monetized PTCs could be placed into a separate FERC 108 account but still treated as a rate base offset as discussed in my prefiled direct testimony.

Q. Do you agree with Mr. Mullins’ statement that it is “not in the best interest of Washington ratepayers to fund remediation expenses today which the Company will not make for another 30 years”?[[130]](#footnote-131)

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

Q. How do you propose that customer’s receive the benefit of the PTCs when they are monetized?

A. I propose to treat the monetized PTCs in the same manner as the hydro-related Treasury Grants and to utilize deferral treatment of the same type that is authorized under RCW 80.80.060[[131]](#footnote-132) until their rate base impact is incorporated in base rates in a future proceeding. This will allow customers to receive the full benefit associated with the PTCs and avoid the situation in which PSE refunds dollars through PTC early amortization only to turn around and increase rates in the future for unrecovered costs at the Colstrip units— especially recognizing those future customers received no benefits from Colstrip.

Q. Please summarize your recommendation?

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

# VIII. EXPEDITED RATE FILINGS

Q. What was the overall response to PSE’s proposal to formalize the expedited rate filing procedures?

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

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

A. Yes. Commission Staff’s testimony recognizes that the Commission currently has a pending rulemaking, Docket A-130355, which may include procedures for a “limited rate filing.” Mr. Schooley, in his response, to Public Counsel Data Requests 2, 4, 6 and 7, which are included as Exhibit KJB-36, indicates he supports PSE’s proposal for an expedited rate filing based on the methods used and approved in Dockets UE-130137 and UG-130138 in the absence of actual rules for such a filing.[[132]](#footnote-133)

Q. Please summarize the positions of the other parties?

A. FEA’s witness Mr. Ali Al-Jabir, Public Counsel witness Mr. Michael L. Brosch, and ICNU witness Mr. Michael P. Gorman all advocate that the Commission reject PSE’s proposal and allow changes in base rates to occur only through a general rate proceeding where all costs, including cost of capital can be reviewed.[[133]](#footnote-134)

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

A. No. All three parties object to an expedited rate filing, in part because it does not include an update to cost of capital. Their concerns that the cost of capital information will be stale, or that conditions could have changed since the rates were last set, I believe are over exaggerated and fail to recognize that a full review of all costs, including cost of capital will have occurred in the recently concluded general rate case filing. The expedited rate filing is intended to be limited in nature, to provide for a limited update to costs while breaking the cycle of back to back general rate cases. Assuming that the expedited rate filing is allowed for up to two years after the cost of capital has been determined in a general rate case, it should be unnecessary for the Commission to require a full cost of capital study to be undertaken in an expedited rate filing. Utilization of the previously approved cost of capital is also consistent with prior Commission orders in which the previously authorized return on equity remained unchanged, when the Commission had recently determined PSE’s cost of capital in a general rate case.[[134]](#footnote-135)

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

A. Mr. Brosch, Mr. Gorman and Mr. Al-Jabir express concern about the expedited schedule, [[135]](#footnote-136) but what they fail to recognize is that the expedited rate filing or limited rate filing is intended to be only a limited update. By utilizing the Commission Basis Report format that is well established and includes only limited restating adjustments with consistent methodologies, this will allow the review to be completed in an expedited manner without prejudice to any party. By removing power costs and pro forma adjustments, which typically are more contentious, the expedited timeline is reasonable. Commission Staff concurs that an expedited rate filing can be completed in this timeframe.[[136]](#footnote-137)

Q. Mr. Brosch suggests that an expedited rate filing should be limited to a period of 12 months after the issuance of the final order in a general rate case rather than the two year period that PSE originally proposed.[[137]](#footnote-138) Do you agree with that timeframe?

A. Not entirely. I support the filing of an initial expedited rate filing within 12 months of the final order from a general rate case proceeding, however, I believe PSE should have the ability to file a second ERF within the 12 months following the completion of an expedited rate filing, a process that was discussed in the draft rules. The opportunity to file more than one expedited rate filing is consistent with the approach proposed by Public Counsel in PSE’s Decoupling/Expedited Rate Filing proceeding. In that 2013 case, Public Counsel opposed the multi-year rate plan and proposed that instead of the K-Factor, PSE be allowed to file two expedited rate filings within the stay-out period.[[138]](#footnote-139)

Q. Mr. Gorman claims that an expedited rate filing would discourage efficient company operations.[[139]](#footnote-140) Do you agree?

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

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

A. No. Public Counsel compares the number of adjustments included in a general rate case to the limited adjustments that are included in a Commission Basis Report and distorts the difference to illustrate what Public Counsel views to be “a very basic problem with the ERF process.”[[140]](#footnote-141) Mr. Brosch fails to recognize that the majority of the “new adjustments” that are “unique” to a particular general rate case tend to be one time annualizing or pro forma adjustments that are typically recognizing increases in costs that will be in place during the rate year; therefore the exclusion of these adjustments *benefits* customers, it does not harm customers. One of the things PSE forgoes by utilizing an expedited rate filing as opposed to a general rate case is the use of pro forma adjustments which typically recognize increases or changes in costs that occur outside of the test year; in return the process is more streamlined.

Q. How do you respond to Mr. Brosch’s statement that PSE has not demonstrated that it will face attrition and therefore PSE’s request to formalize the expedited rate filing procedures should be rejected?[[141]](#footnote-142)

A. I disagree with Mr. Brosch’s assertion that a showing of attrition is necessary for an expedited rate filing, and Mr. Brosch provides no support for his viewpoint. As Mr. Schooley acknowledges in Commission Staff’s Response to Public Counsel Data Request No. 2, the Commission did not state in 2013 that attrition must be shown.[[142]](#footnote-143) PSE has in the past filed both a gas tariff increase filing[[143]](#footnote-144) and an expedited rate filing[[144]](#footnote-145) that are limited scope filings to update costs. Neither the procedural rules nor the Commission past order have required a showing of attrition before such filings can be considered. The point here is to add some certainty to these proceedings and from PSE’s and Commission Staff’s perspective, the 2013 expedited rate filing is a good model to follow in terms of the procedural timeframe and the scope of the proceeding.[[145]](#footnote-146)

Q. ICNU witness Mr. Gorman claims an expedited rate filing is single issue ratemaking.[[146]](#footnote-147) Do you agree?

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

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

A. Both Mr. Gorman and Mr. Brosch make accusations that PSE can cherry pick and include only “certain costs for ERF review.”[[147]](#footnote-148) This is simply not true. The expedited rate filing format that PSE used and that the Commission approved was based on the format proposed by Commission Staff in the 2011 general rate case. It included a complete matching of revenues and expenses associated with non-production related assets. As discussed in that original expedited rate filing, excluding power costs made sense for a number of reasons, the primary one being the power costs are typically reviewed on a forward looking basis and as a result would add unneeded complexity to a filing that is intended to be “expeditious”. In filing an expedited rate filing, PSE gives up the opportunity to propose pro forma adjustments, thus streamlining the process. With the filing occurring within one to two years of the completion of a general rate case, an expedited rate filing merely represents an update to cost information during the pendency of the case.

The arguments of ICNU and Public Counsel were rejected by the Commission in 2013 when PSE’s original expedited rate filing was accepted and they should be rejected again.

# IX. ELECTRIC COST RECOVERY MECHANISM

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

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

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

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

Q. ICNU suggests recovery of costs in a rider are only appropriate when those costs are significant, volatile, and beyond the utility’s control.[[148]](#footnote-149) Do you agree?

A. No. The proposed plan and mechanism is intended to follow similar processes that have evolved with the gas pipeline replacement plan and cost recovery mechanism and I believe is consistent with the transparency the Commission sought in a recent Avista general rate case, when the Commission questioned the higher level of investment in replacing Avista’s aging infrastructure.[[149]](#footnote-150)

Q. How does PSE respond to Commission Staff’s position that the ECRM is not needed because PSE “will receive rates to recover any investment after that investment is in service and in the due course of Commission proceedings”?[[150]](#footnote-151)

A. Unfortunately, Commission Staff is ignoring the fact that “due course” is typically 27 months after the investment has been placed in service and providing benefits to customers. The heightened level of annual expenditures associated with the accelerated reliability improvements outlined in the Electric Reliability Plan would result in significant earnings erosion absent the ECRM mechanism. Exhibit KJB-37[[151]](#footnote-152) demonstrates the regulatory lag that would be associated with having to absorb the level of investment contemplated in the Electric Reliability Plan. This exhibit demonstrates that under traditional ratemaking that utilizes average of monthly average (“AMA”) balances, it takes a full 12 months before the entire investment is reflected in the AMA test year balance. Assuming that a rate case can be prepared and filed in three months, plus the 11 months associated with the statutory suspension period prior to approval in rates, it is more than two years before PSE begins to recover its costs through rates. The two-year delay in recovery of the 2017 ECRM investments would be equal to approximately $20 million of lost revenue requirement which is nearly 20 basis points per year in earnings.

Additionally, it is disappointing to see Commission Staff’s complete rejection of the ECRM particularly when one considers Commission Staff’s recent position on increased reliability spending by another regulated utility. In Commission Staff’s testimony in the Avista 2015 general rate case, Commission Staff “questioned the need for Avista to “invest heavily” in distribution plant because Avista has not provided evidence supporting the need to maintain or improve reliability.”[[152]](#footnote-153) In that case, Commission Staff further stated that:

without knowing where Avista should be in terms of its reliability performance, it is not possible to know whether improved “reliability” is a remotely acceptable cause for significant and continued investment in distribution system enhancements. It is entirely possible that, given the unique characteristics of Avista’s service territory, it has already invested far too heavily in distribution system enhancements[[153]](#footnote-154)

The Commission agreed with Commission Staff’s observation and stated we “emphasize that we share Commission Staff’s frustration about continuing to authorize recovery for these significant capital investments, *absent a complete demonstration by the Company of quantifiable benefits to ratepayers*.”[[154]](#footnote-155)

PSE, through the prefiled direct testimonies of Booga K. Gilbertson and Catherine A Koch, have demonstrated a clear need to improve PSE’s reliability and have provided the Electric Reliability Plan as a pathway to improved reliability and the anticipated improvements that will result from these investments. Rather than embracing the opportunity to participate in constructive dialog, parties including Commission Staff believe that PSE’s filing along with the associated cost recovery mechanism will be burdensome. Absent this process, PSE will be reluctant to spend beyond the levels supported by growth.

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

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

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

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

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

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

# X. MATERIALITY AND OTHER NON-REVENUE REQUIREMENT ISSUES

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

A. In general, PSE would be supportive of discontinuing the small adjustments as proposed by Mr. Schooley.[[155]](#footnote-156) Many of these adjustments were the result of proposed adjustments by Commission Staff or other parties in prior proceedings that were ultimately approved by the Commission, either because PSE did not contest them or they were explicitly approved in the final order. Therefore, PSE was reluctant to unilaterally omit them absent a Commission order allowing such exclusion.

Q. Ms. Cheesman proposes a materiality threshold for reviewing and including certain adjustments?[[156]](#footnote-157)

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

Q. Ms. Cheesman includes several pages in her testimony regarding communication and the need for clarity in PSE’s terminology and adjustment files.[[157]](#footnote-158) Do you agree with her assessment?

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

# XI. CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes.

1. As well as the impact on revenue requirement for the contingent calculation related to the Microsoft special contract approved in Docket UE-161123. [↑](#footnote-ref-2)
2. Brosch, MLB-1T at 21:9. [↑](#footnote-ref-3)
3. Docket UE-121697/UG121705, Public Counsel witness Dittmer at 5-13. [↑](#footnote-ref-4)
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. [↑](#footnote-ref-5)
5. Dockets UE-121697/UG-121705, Barnard, Exh. KJB-16. [↑](#footnote-ref-6)
6. Brosch, MLB-1T at 22:5. [↑](#footnote-ref-7)
7. Barnard, Exh. KJB-1T at 8:9-12. [↑](#footnote-ref-8)
8. Brosch, MLB-1T at 22:13-16. [↑](#footnote-ref-9)
9. Brosch, MLB-1T at 38:13-21. [↑](#footnote-ref-10)
10. Hancock, Exh. CSH-1CT at 29:1-2; Smith, RCS-1CT at 68:12-13. [↑](#footnote-ref-11)
11. Mullins, Exh. BGM-3 at 1:21. [↑](#footnote-ref-12)
12. Liu, Exh. JL-1CT at 3:1-4. [↑](#footnote-ref-13)
13. *See generally* McGuire, Exh. CRM-1T at 21. [↑](#footnote-ref-14)
14. McGuire, Exh. CRM-1T at 16:22. [↑](#footnote-ref-15)
15. *See* Docket UE-072300, Clarke, Exh. CRC-1T. [↑](#footnote-ref-16)
16. *See* Docket UE-072300, King, Exh. CWK-1T at 3. [↑](#footnote-ref-17)
17. *See* Docket UE-072300, Weinman, Exh. WHW-1T at 7-10. [↑](#footnote-ref-18)
18. *See* Docket UE-072300, Jones, Exh. MLJ-15T at 8-13. [↑](#footnote-ref-19)
19. *See* Docket UE-072300, Exhibit Joint-7T, Joint Testimony Re Electric and Natural Gas Revenue Requirements. [↑](#footnote-ref-20)
20. *See generally* McCullar, Exh. RMM-1T. [↑](#footnote-ref-21)
21. Hausman, Exh. EDH-1T at 6:5-6. [↑](#footnote-ref-22)
22. Hausman, Exh. EDH-1T at 12:16-18. [↑](#footnote-ref-23)
23. McGuire, Exh. CRM-1T at 5:13. [↑](#footnote-ref-24)
24. McGuire, Exh. CRM-1T at 16:13-18. [↑](#footnote-ref-25)
25. Please seethe 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. [↑](#footnote-ref-26)
26. McGuire, Exh. CRM-1T at 30-31. [↑](#footnote-ref-27)
27. McGuire, Exh. CRM-1T at 19:14-15. [↑](#footnote-ref-28)
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. [↑](#footnote-ref-29)
29. McGuire, Exh. CRM-1T at 31-32. [↑](#footnote-ref-30)
30. *State ex rel. Pac. Power & Light Co. v. Dep’t of Pub. Works*, 143 Wn. 67, 254 P. 839 (1927). [↑](#footnote-ref-31)
31. 143 Wn. at 86, 254 P. at 846. [↑](#footnote-ref-32)
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). [↑](#footnote-ref-33)
33. Mullins, Exh. BGM-1T at 6:10-12 and 20:6-11. [↑](#footnote-ref-34)
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). [↑](#footnote-ref-35)
35. Mullins, Exh. BGM-1CT at 11:10-12. [↑](#footnote-ref-36)
36. Mullins, Exh. BGM-1CT at 11:12-14. [↑](#footnote-ref-37)
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). [↑](#footnote-ref-38)
38. Mullins, Exh. BGM-1CTat 21:10‑22:13. [↑](#footnote-ref-39)
39. Hausman, Exh. EDH-1T at 6:15-20. [↑](#footnote-ref-40)
40. Hausman, Exh. EDH-1T at 22:14. [↑](#footnote-ref-41)
41. Marcelia, Exh. MRM-1T at 37:9 ‑ 38:10. [↑](#footnote-ref-42)
42. Barnard, Exh. KJB-1T at 31. [↑](#footnote-ref-43)
43. Hausman, Exh. EDH-1T at 39:10-14. [↑](#footnote-ref-44)
44. *Id.* at 6:15-17. [↑](#footnote-ref-45)
45. *Id.* at 31:11-12. [↑](#footnote-ref-46)
46. Power, Exh. TMP-1T at 15:17-18. [↑](#footnote-ref-47)
47. *Id.* at 11:6-9. [↑](#footnote-ref-48)
48. *Id.* at 17:21-22. [↑](#footnote-ref-49)
49. *Id.* at 18:17-18. [↑](#footnote-ref-50)
50. Smith, Exh. RCS-1CT at 40:12-21. [↑](#footnote-ref-51)
51. McCullar, Exh. RMM-1T at 5:Table 1. [↑](#footnote-ref-52)
52. Barnard, Exh. KJB-27. [↑](#footnote-ref-53)
53. Public Council Proposed Depreciation expense of $491,610.51 divided by “Amortized” FERC 397 plant value of $63,796,964 = 0.77% [↑](#footnote-ref-54)
54. Smith, Exh. RCS-1CT at 42:1 – 47:15. [↑](#footnote-ref-55)
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. [↑](#footnote-ref-56)
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. [↑](#footnote-ref-57)
57. Smith, Exh. RCS-1T at 47:10. [↑](#footnote-ref-58)
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.” [↑](#footnote-ref-59)
59. Smith, Exh. RCS-1CT at 56:16-17. [↑](#footnote-ref-60)
60. *Id.* at 59:3-4. [↑](#footnote-ref-61)
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. [↑](#footnote-ref-62)
62. Smith, Exh. RCS-1CT at 55:1-12. [↑](#footnote-ref-63)
63. Mullins, Exh. BGM-1CTr at 38:7-11. [↑](#footnote-ref-64)
64. Mullins, Exh. BGM-1CT at 37:15-16. [↑](#footnote-ref-65)
65. *Id.* at 39:1-7. [↑](#footnote-ref-66)
66. Free, Exh. SEF-12T. [↑](#footnote-ref-67)
67. Free, Exh. SEF-12T. [↑](#footnote-ref-68)
68. *See generally* Liu, Exh. JL-1CT at 46:1 – 56:12. [↑](#footnote-ref-69)
69. Production O&M, 557 Other Power Supply Expenses and 456 OATT Revenues. [↑](#footnote-ref-70)
70. Schooley, Exh. TES-1T at 21:14 – 22:8. [↑](#footnote-ref-71)
71. Higgins, Exh. KCH-1T at 5:19 – 6:2. [↑](#footnote-ref-72)
72. Smith, Exh. RCS-1CT at 36:3-13. [↑](#footnote-ref-73)
73. Docket UE-921262, Schooley, Exh. TES-1T. [↑](#footnote-ref-74)
74. Docket UE-040640, Kilpatrick, Exh. DEK-1T at 8:3-6. [↑](#footnote-ref-75)
75. Schooley, Exh. TES-1T at 21:18 – 22:19. [↑](#footnote-ref-76)
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. [↑](#footnote-ref-77)
77. Schooley, Exh. TES-1T at 19:2-10. [↑](#footnote-ref-78)
78. *Id.* at 19:4-6. [↑](#footnote-ref-79)
79. *Id.* at 21:17-21. [↑](#footnote-ref-80)
80. *See* Dockets UE-1111048, *et al.*, Order 08, 104 ¶ 299. [↑](#footnote-ref-81)
81. Barnard, Exh. KJB-32. [↑](#footnote-ref-82)
82. Ms. Cheesman reflects the six year normal storm average as recommended by Mr. Schooley on page 2 of his Exhibit TES-3. [↑](#footnote-ref-83)
83. Work paper filed in support of Exhibit TES-2, tab “qualifying event” included as Exhibit KJB-34. [↑](#footnote-ref-84)
84. Schooley, Exh. TES-1T at 23:16. [↑](#footnote-ref-85)
85. *Id.* at 23:21-22. [↑](#footnote-ref-86)
86. Cheesman, Exh. MCC-1T at 24:1-5. [↑](#footnote-ref-87)
87. $39.6 million ÷ $530,000 = 74.7 basis points. $530,000 is found in Response Testimony of Ms. Melissa C. Cheesman, Exhibit MCC-1T at 24:4. [↑](#footnote-ref-88)
88. Schooley, Exh. TES-1T at 24:2-7. [↑](#footnote-ref-89)
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. [↑](#footnote-ref-90)
90. Schooley, Exh. TES-1T at 25:2-8. [↑](#footnote-ref-91)
91. *Id.* at 24:17-21. [↑](#footnote-ref-92)
92. Higgins, Exh. KCH-1T at 5:20 – 6:2. [↑](#footnote-ref-93)
93. *Id.* at 6:3-9. [↑](#footnote-ref-94)
94. Smith, Exh. RCS-1CT at 36:5-7. [↑](#footnote-ref-95)
95. Frankiewich, Exh. KAF-1T at 13:15 – 14:15. [↑](#footnote-ref-96)
96. *See Wash. Utils. & Transp. Comm’n v. Puget Sound Energy*, Docket UE-130617, *et al*., Order 11 at ¶ 18 (Aug. 7, 2015). [↑](#footnote-ref-97)
97. *See id.* at ¶ 20. [↑](#footnote-ref-98)
98. Frankiewich, Exh. KAF-1T at 13:17 – 14:15. [↑](#footnote-ref-99)
99. *Id.* at 6:4. [↑](#footnote-ref-100)
100. *Id.* at 7:7-8. [↑](#footnote-ref-101)
101. *Id.* at 14:10-12. [↑](#footnote-ref-102)
102. *Id.* at 11:13-16. [↑](#footnote-ref-103)
103. *See* Barnard, Exh. KJB-1T at 49:19 – 50:4. [↑](#footnote-ref-104)
104. Wright, Exh. ECW-1T at 4:8-12. [↑](#footnote-ref-105)
105. *Id.* at 16:18-21. [↑](#footnote-ref-106)
106. *Id.* at 16. [↑](#footnote-ref-107)
107. *Id.* at 17:4-6. [↑](#footnote-ref-108)
108. Wetherbee, Exh. PKW-1CT at 78:9-10. [↑](#footnote-ref-109)
109. Wright, Exh. ECW-1T at 15:9-10. [↑](#footnote-ref-110)
110. Wright, Exh. ECW-1T at 16:11-13. [↑](#footnote-ref-111)
111. Further discussion on the use of PTCs to address decommissioning and remediation costs is found in Section VII of my testimony. [↑](#footnote-ref-112)
112. Mullins, Exh. BGM-1CT at 32:7 - 37:6. [↑](#footnote-ref-113)
113. *Id.* at 36:10-19. [↑](#footnote-ref-114)
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. [↑](#footnote-ref-115)
115. *Wash. Utils. & Transp. Comm’n v. Puget Sound Energy*, Docket UE-130617, *et al*., Order 6 at ¶ 65 (Oct. 23, 2015). [↑](#footnote-ref-116)
116. Mullins, Exh. BGM-3 at 1:41. [↑](#footnote-ref-117)
117. Smith, RCS-3 Supplemental, 1:38, where it reflects “PC Accepted.” [↑](#footnote-ref-118)
118. Brosch, Exh. MLB at 3:17-20. [↑](#footnote-ref-119)
119. *Id.* at 43:20 - 44:4. [↑](#footnote-ref-120)
120. Smith, Exh. RCW-1CT at 20:4-11. [↑](#footnote-ref-121)
121. *See* Marcelia, Exh. MRM-1T. [↑](#footnote-ref-122)
122. Mullins, Exh. BGM-1CT at 32:7 – 37:6. [↑](#footnote-ref-123)
123. *Id.* at 54:8-12. [↑](#footnote-ref-124)
124. Although the Energy Imbalance Market Adjustment 21.08 is contested, the amount is not. [↑](#footnote-ref-125)
125. Hancock, Exh. CSH-1T at 16:11-15. [↑](#footnote-ref-126)
126. The depreciation rates approved in UE-072300 became effective in November 2008. [↑](#footnote-ref-127)
127. *See, e.g.,* Hausman, Exh. EDH-1T at 6:5-14; Power, Exh. TMP-1T at 12:2 – 15:3. [↑](#footnote-ref-128)
128. Barnard, Exh. KJB-1T at 84:21 – 85:15. [↑](#footnote-ref-129)
129. Hancock, Exh. CSH-1CT at 16:3-15; Mullins, Exh. BGM-1CT at 34:12-18. [↑](#footnote-ref-130)
130. Mullins, Exh. BGM-1CT at 17:7-9. [↑](#footnote-ref-131)
131. RCW 80.80.060(6) provides for the deferral of costs associated with long-term financial commitments related to baseload electric generation. [↑](#footnote-ref-132)
132. Barnard, Exh. KJB-36 at 9. [↑](#footnote-ref-133)
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. [↑](#footnote-ref-134)
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). [↑](#footnote-ref-135)
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. [↑](#footnote-ref-136)
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.”) [↑](#footnote-ref-137)
137. Brosch, Exh. MLB-1T at 65:1-2. [↑](#footnote-ref-138)
138. Dockets UE-130137, *et al*., Dittmer, Exh. JRD-1T at 41:14-16. [↑](#footnote-ref-139)
139. Gorman, Exh. MPG-1T at 38:21-22. [↑](#footnote-ref-140)
140. Brosch, Exh. MLB-1T at 66:13-16. [↑](#footnote-ref-141)
141. *Id*. at 69:11. [↑](#footnote-ref-142)
142. Barnard, Exh. KJB-36 at 2. [↑](#footnote-ref-143)
143. Docket UG-101644. [↑](#footnote-ref-144)
144. Dockets UE-130137 & UG-130138. [↑](#footnote-ref-145)
145. Barnard, Exh. KJB-36 at 7. [↑](#footnote-ref-146)
146. Gorman, Exh. MPG-1T at 36:13-14. [↑](#footnote-ref-147)
147. Gorman, Exh. MPG-1T at 36:14-16; Brosch, Exh. MLB-1T at 13:10-12. [↑](#footnote-ref-148)
148. Gorman, Exh. MPG-1T at 42:18-19. [↑](#footnote-ref-149)
149. *WUTC v. Avista,* Docket UE-150204/UG-150205, Order 05 ¶ 116. [↑](#footnote-ref-150)
150. Schooley, Exh. TES-1T at 28:17-18. [↑](#footnote-ref-151)
151. Excerpt from PSE’s Response to Public Counsel Data Request No. 72. [↑](#footnote-ref-152)
152. *Wash. Utils. & Transp. Comm’n v. Avista*, Dockets UE-150204 and UG-150205, Order 5 at ¶ 81 (Jan. 6, 2016). [↑](#footnote-ref-153)
153. *Id.* at ¶ 98 referencing McGuire, Exh. CRM-1T at 24:19-21. [↑](#footnote-ref-154)
154. *Id.* at ¶ 141 (emphasis added). [↑](#footnote-ref-155)
155. Schooley, Exh. TES-1T at 17:19-22. [↑](#footnote-ref-156)
156. Cheesman, Exh. MCC-1T at 23:13-19. [↑](#footnote-ref-157)
157. *Id.* at 26:11 - 30:6. [↑](#footnote-ref-158)