EXHIBIT NO. ___(JHS-18T)
DOCKET NOS. UE-111048/UG-111049
2011 PSE GENERAL RATE CASE
WITNESS: JOHN H. STORY

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-111048** **Docket No. UG-111049**

PREFILED REBUTTAL TESTIMONY (NONCONFIDENTIAL) OF
JOHN H. STORY
ON BEHALF OF PUGET SOUND ENERGY, INC.

January 17, 2012

PUGET SOUND ENERGY, INC.

PREFILED REBUTTAL TESTIMONY (NONCONFIDENTIAL) OF JOHN H. STORY

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PUGET SOUND ENERGY, INC.

PREFILED REBUTTAL TESTIMONY (NONCONFIDENTIAL) OF JOHN H. STORY

I. INTRODUCTION

Q. Are you the same John H. Story who submitted prefiled direct testimony in this proceeding on June 13, 201, and supplemental prefiled direct testimony in this proceeding on September 1, 2011, each on behalf of Puget Sound Energy, Inc. ("PSE" or "the Company")?

A. Yes.

Q. Please summarize the purpose of your rebuttal testimony.

A. My testimony discusses the various electric pro forma and restating adjustments that the Company is proposing in rebuttal. I will discuss the Commission's application of the pro forma rule as it relates to production resources that was adopted in PSE's 2009 general rate case. I discuss the partial settlement's impact on REC's.

I present the uncontested electric adjustments between Commission Staff and the Company. I will also explain why some of the uncontested electric adjustments have different impacts for net operating income ("NOI") and rate base from what is presented in Commission Staff's presentation. I discuss specific electric restating and pro forma adjustments proposed by Commission Staff and other parties that are different from the Company's adjustment and explain why the Company disagrees with their proposed adjustments. I will respond to

Commission Staff's testimony concerning attrition and some of the issues presented concerning the Power Cost Adjustment ("PCA") Mechanism. Finally, I present the exhibits that support the PCA calculation during the rate year using the Company's pro forma and restating adjustments for production and other power costs.

Taking into consideration the pro forma and restating electric adjustments proposed by the Company and presented in Exhibit No. ___ (JHS-19), there is an electric revenue deficiency of $125,401,321 after allocation of $591,462 to Firm Resale and Firm Wholesale customers. If approved, this would represent an average 6.34% rate increase.

II. COMPARISON OF THE COMPANY'S REVENUE DEFICIENCY AND COMMISSION STAFF'S REVENUE DEFICIENCY

Q. Have you prepared a reconciliation between the revenue deficiency filed by the Company and the revenue deficiency filed by Commission Staff?

A. Yes. The following table highlights the differences, in millions, between the Company's supplemental filing, the Company's rebuttal filing and the Commission Staff filing.

1	PSE Supplemental Deficiency	$ 152.9
2	Include Deferral of LSR costs	7.5
3	Update LSR for earlier in-service date	(5.2)
2	Update cost of debt and cost of equity	(8.8)
3	Update Power Costs	(21.5)
4	Other Miscellaneous Changes	1.1
5	Total Changes from Supplemental Filing	(26.9)
6		
7	PSE Rebuttal Deficiency	126.0
8	Differences Between PSE and Staff by Adjustment:	
9	22.02 Rate of Return on Actual Results of Operations	(44.3)
10	20.02 Lower Snake River Plant Adjustment	(13.1)
11	21.04 Federal Income Tax	(5.1)
12	20.01 Power Costs	(5.7)
13	21.11 Property Taxes	(4.6)
14	Various - Due to differing ROR and/or final rate base	(4.2)
15	21.22 Working Capital	(4.1)
16	21.10 Incentive Pay	(2.9)
17	Staff Adjustment - REC Liability	(1.3)
18	Other Miscellaneous Adjustments	(1.8)
19	Total Differences	(87.1)
20		
21	Commission Staff Revenue Deficiency	$ 38.9

Q. Did you prepare a reconciliation that shows the differences between other parties' pro forma and restating adjustments and the Company's adjustments?

A. No. The other parties did not present their exhibits in a manner that would allow such a comparison. Where there are differences between the Company and other parties on specific adjustments these differences will be discussed when I present the actual adjustment.

III. PRO FORMA ADJUSTMENTS

Q. What is the purpose of your testimony on pro forma adjustments?

A. I am concerned that in PSE's last general rate case the Commission adopted an overly restrictive view of pro forma adjustments that is inconsistent with decades of prior rulings. In those prior cases the Commission has recognized that not all things in rate cases are provable with absolute certainty or are precisely measurable, and the Commission has allowed pro forma adjustments in which estimates are based on professional judgment. I provide a summary of some of these past Commission decisions, and I also discuss some inconsistencies with the pro forma adjustments Commission Staff proposed, and the Commission accepted in PSE's 2009 general rate case relating to production plant—specifically the Wild Horse Expansion. Commission Staff has perpetuated these inconsistencies in the current case when proposing adjustments for PSE's Lower Snake River wind plant ("LSR"). PSE respectfully requests that the Commission take a closer look at the Company's adjustments in the context of previous Commission decisions based on professional judgment, reasonableness, and consistency between similar adjustments.

A. <u>Commission's Historical Application of the Pro Forma Adjustment Standard</u>

Q. Are you aware of the definition of pro forma adjustments in the Washington Administrative Code ("WAC")?

A. Yes. WAC 480-07-510(3)(iii) states:

> Pro forma adjustments give effect for the test period to all known and measurable changes that are not offset by other factors. The work papers must identify dollar values and underlying reasons for each proposed pro forma adjustment.

Q. How has this definition been applied in prior Company cases?

A. As I presented in the Company's 2009 general rate case, the application of this definition is dependent on the particular pro forma adjustment. In some situations the requirement that pro forma adjustments be "known and measurable changes that are not offset by other factors" is met when the company provides a reasonable estimate, based on professional expertise. For example, in a proceeding over thirty years ago, *WUTC v. Wash. Natural Gas*, Docket. U-77-47 (1977), the Commission stated as follows:

> The company made a pro forma adjustment resulting in an increase of $170,988 to its maintenance expense during the test year (Line 3, Column M, Sheet 2, Exhibit 10) resulting in a decrease to its net operating income of ($88,914) (Line 15, Column M, Sheet 2, Exhibit 10) for the test year. The company contends that the increased maintenance cost is attributable to the recently adopted rules of the Commission pertaining to reclassification of leaks. The company contends had the new rules been in effect during the test year, that an additional 256 maintenance jobs would have been required at a cost of $99,672, and the company would be required to reevaluate all Class B leaks on a time schedule not exceeding 15 months at an annual cost of $26,316 and finally that the additional office and administrative costs incurred due to the compilation of reports and other internal office data directly attributable to the new rules results in an additional cost of $45,000 annually.

> The staff rejects the company's pro forma adjustment asserting that the company has not demonstrated that compliance with the new rules will result in increased costs. The staff points out that Mr. Hoglund cannot with certainty project the number of leaks which might occur in the future (5 years hence) and that the number of leaks vary from year to year, and Mr. Hoglund's testimony

> estimating the approximately 40% of all B2 leaks would be reclassified as Class C leaks subject to the 15-month resurvey requirement was not made on historical experience but was made on an "engineering" judgment, not supported by any known and measurable data.
>
> **The Commission recognizes the concern of the staff that the company's treatment of this adjustment is based upon a projection and not actual experience.** However, the Commission recognizes that not all things in a rate case hearing are provable with absolute certainty or are precisely measurable. For example, the rate of return necessarily includes a judgment factor. The company's engineering staff has vast and extensive experience in dealing with maintenance and as a professional staff we recognize it has developed a degree of expertise which goes into its judgment. We must and do recognize that a judgment or projection made by people having special expertise has credibility, if the projection is supported by believable testimony and experience. We believe it is ***reasonable*** (emphasis added) to assume that the new rules on reclassification of leaks will result in additional maintenance and expenses, and on a whole the company will as a result of the new rules incur additional expenses. Accordingly the company's adjustment will be allowed. [Emphasis added.]

As discussed above, the Commission recognized that not all things in a rate case are provable with absolute certainty or precisely measurable. There are many items that are estimates such as depreciation, weather normalization, line losses, power costs, property taxes, rate year load, cost of service allocations and, as noted above, rate of return. These all rely on estimates that have been determined to be reasonable by the Commission.

Q. In the 2009 general rate case did you present more recent Commission decisions supporting this view of pro forma adjustments?

A. Yes. In Docket UE-031725, the Commission approved pro forming into the rate year PSE's Fredrickson I generation plant, as its purchase date was expected to be coincident with the Commission order. In its Findings of Fact, item 6 the Commission states as follows:

> PSE has carried its burden to show that the costs the Company proposes to include in rates for the PCORC rate period, as modified during the course of the proceeding and reflected in Exhibit No. 318, line 5, are reasonable.[1]

In the Conclusions of Law, item 3, in Order 12 of the same docket, the Commission states as follows:

> Including PSE's costs associated with its acquisition of Frederickson I, as reflected in Exhibit No. 318, line 5, in PSE permanent rates at the time PSE places the plant in service will result in rates, terms, and conditions of service that are fair, just, reasonable, and sufficient.[2]

In Docket Nos. UG-04640 *et al*, UE-040641, UE-031471 and UE-032043, Order No. 06, paragraph 108, the Commission states as follows:

> [P]ower costs determined in general rate proceedings and in PCORC proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings.[3]

Q. Did the Commission follow these stated policies in the Company's last general rate case, Docket No. UE-090704 et al, as they relate to new production resources?

A. No. In that docket, Commission Staff proposed that only the actual construction

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[1] *Wash. Utils. & Transp. Comm.*, Docket UE-031725, Order 14, ¶ 110.

[2] *Id.* Order 12, ¶69.

[3] *Wash. Utils. & Transp. Comm*, Docket UG-040640 & UE-040641, Order 06 (January 7, 20007), ¶ 108.

costs known through August 2009 be used to determine return on and of the Wild Horse Expansion being built by the Company. This new plant addition was going to being added to the Company's production resources with an in-service date of December 2009. Commission Staff also removed property taxes associated with this project from their adjustment and adjusted depreciation to reflect their plant cost. The Commission accepted Commission Staff's adjustment stating their adjustment meets the requirements of a pro forma adjustment used in historic test year ratemaking in terms of being known and measurable. This was a change from how production plant additions had been accepted in previous filings.

Q. Did Commission Staff's costs reflect all known and measurable costs for the Wild Horse Expansion adjustment?

A. No. In the response testimony filed in November 2009, Commission Staff reflected the actual costs through August 2009, however, they did not include all the known and measurable costs. For example, AFUDC is a known cost of construction work in progress, but Commission Staff calculated no AFUDC after August 2009 for this plant even though the plant was not going to be placed into service until December of that year.

Q. Did Commission Staff consistently apply this methodology to all adjustments related to the Wild Horse Expansion in the 2009 case?

A. No. Although Commission Staff used only actual costs through August 2009 for the plant cost adjustment, Commission Staff used the Company's estimated in-service date of December 2009 and the Company's estimated costs to complete the plant as of that date for its Wild Horse Expansion Deferred Cost Adjustment.

Q. Please provide a brief history of the Wild Horse Expansion Deferred Cost Adjustment from the PSE 2009 general rate case.

A. The Company had not proposed this adjustment in its original filing in 2009, however, under RCW 80.80.060 a company is allowed to defer the costs of certain resources until they are included in rates. Commission Staff was aware that the Company was going to begin deferring costs under this statute and proposed an adjustment to recover the deferred amount over two years. Ironically, although Commission Staff did not use plant costs beyond August 2009 in its Wild Horse Expansion plant adjustment, it did use the Company's December 2009 estimates of the cost of construction for the plant to determine the Wild Horse Expansion deferral. Commission Staff's deferral calculation also included the Company's estimate for property tax expense in the operating costs—even though Commission Staff had not included property taxes for the plant adjustment.

Q. Did the Commission accept these inconsistent adjustments in PSE's 2009 general rate case?

A. Yes, the Commission accepted both of Commission Staff's adjustment. I believe the Commission may have overlooked the inconsistent logic in these two adjustments as it was not discussed in testimony, which is why I am highlighting this issue in my testimony in this case. I believe it is important that the

Commission not perpetuate this treatment of pro forma adjustments relating to production plant and should take another look at these adjustments in tandem, because the same issue arises in the current case in regard to the LSR adjustments.

Q. What was the difference between what the Commission allowed for rate base in the Wild Horse Expansion Adjustment and the actual in-service amount closed to plant when the plant became operational?

A. The Company's forecasted plant balance was $98,431,202 through December 2009 and the Commission accepted Commission Staff's proposal to use $90,388,143 that was closed to plant through August 2009. The actual amount closed to in-service in December 2009 was $98,060,980. The impact on revenue deficiency for the difference between Commission Staff's estimate and the actual in-service amount was $1,216,448. The impact on revenue deficiency for the difference between Company's estimate and the actual in-service amount was $47,419. In effect the Company was penalized $1.2 million so that customers would not be "overbilled" $47 thousand.

Q. Did Commission Staff propose adjusting any of the benefits of Wild Horse Expansion, such as the power output, in their adjustments?

A. No.

B. Commission Staff's Application of Pro Forma Adjustments in this Case

Q. Is Commission Staff proposing similar type adjustments to new production resources in this docket?

A. Yes. Commission Staff is proposing that construction costs through October 2011 be used to determine the rate base cost associated with Lower Snake River ("LSR"). They have also included costs associated with contracts that are known and measurable but not yet paid and removed the property taxes associated with the plant. Commission Staff's current adjustment is similar to the Wild Horse Expansion adjustment in that it does not include the additional known and measurable cost of AFUDC that will be incurred prior to the in-service date of the plant or the additional construction costs to complete the plant. If Commission Staff were to correct their AFUDC on this plant it would add approximately $15.4 million to their plant value. Even with this adjustment the Commission Staff plant value would still be $7.6 million lower than the Company's expected cost to complete the project.

Similar to the last general rate case, Commission Staff has an additional adjustment related to LSR, which is the deferral allowed under RCW 80.80.060. Again, Commission Staff's deferral adjustment is based on the Company's estimated total costs to construct LSR, rather than the actual costs plus known and measurable costs through October that Commission Staff is using to determine the in-service cost of LSR for its plant adjustment. However, in this proceeding Commission Staff is removing property taxes for determining the actual costs to be deferred. This is a change from the last proceeding where a similar deferral was calculated for Wild Horse Expansion that included property taxes. Mr. Marcelia discusses property taxes in his prefiled rebuttal testimony, Exhibit No. ___ (MRM-14T), and why the Commission should not accept this part of the deferral adjustment.

Q. **What is the difference between the Company's and Commission Staff's adjustment for plant costs for LSR?**

A. The Company's plant balance in the LSR Plant Adjustment is $765,360,848 (the same amount Commission Staff has used to determine the LSR Deferral Adjustment). In Commission Staff's LSR Plant Adjustment the plant balance is $742,505,032 excluding the additional AFUDC. If Commission Staff's plant balance is adjusted to include AFUDC on their plant costs from November 2011 through the in-service date of mid February, their plant balance would be $757,905,032.

Q. **Has Commission Staff provided any explanation as to why it is appropriate to use construction work in progress costs through a date prior to the in-service date for a new resource and the estimated cost of completion for the same project in another adjustment?**

A. No. One can only speculate that Commission Staff feels that the RCW 80.80.060 deferral should be as accurate as possible. However, the pro forma plant adjustment should also be as accurate as possible.

Q. Is Commission Staff's removal of property taxes from the LSR Deferral Adjustment consistent with the deferral allowed under RCW 80.80.060?

A. No, RCW 80.80.060(6) allows PSE to defer costs incurred in connection with LSR, including operations and maintenance costs, depreciation, taxes, and cost of invested capital.

Q. What is a reasonable pro forma adjustment for a new plant that begins operations in the test year?

A. In the case of a pro forma adjustment for a new plant coming on line that has no test year history of maintenance, property taxes or insurance the Company must be permitted to use reasonable estimates for these costs plus a reasonable estimate of the in-service plant value. If the Commission is concerned that these estimates are too high, then the Commission approval can contain a provision for refund of revenues collected in excess of what was actually closed to plant. The Company can calculate this difference and include the adjustment in the next general rate case. If the Company's estimated cost included in this filing is less than what actually closes to plant, then there would not be any adjustment.

IV. RENEWABLE ENERGY CREDIT PROCEEDS

Q. Has the Company proposed any adjustment in this proceeding for the net proceeds from the sale of renewable energy credits ("REC") that are being deferred as a liability on the Company's books?

A. No. The net proceeds from the REC sales were addressed in a separate proceeding, Docket No. UE-070725. In that docket the Commission ordered that any balance of RECs left on the books, after the offset against Production Tax

Credits being collected from customers, be amortized as a production related regulatory liability over five years. The parties to the current proceeding agreed in settlement to recommend that the Commission move RECs to a separate tariff and provide the benefits of RECs to customers over three years. Separate testimony supports this settlement recommendation in Exhibit No. ___(SPE-1T). Commission Staff had included an estimate for RECs in their Regulatory Assets and Liability Adjustment, Exhibit No. ___ (RCM-2), Adjustment 13.10, and this item should be removed if the Commission accepts the parties' settlement proposal.

V. UNCONTESTED ELECTRIC ADJUSTMENTS BETWEEN THE COMPANY AND COMMISSION STAFF

Q. Have you prepared exhibits that detail the updated restating and pro forma electric adjustments that the Company is supporting?

A. Yes. Exhibit No. ___ (JHS-19) summarizes the Company's electric restating and pro forma adjustments. This exhibit is presented in the same format as my Exhibit Nos. ___ (JHS-4) and (JHS-12) and Mr. Martin's Exhibit No. ___ (RCM-2). Exhibit No. ___ (JHS-20) provides more detail for the restating and pro forma adjustments that are electric specific and Exhibit No. ___ (JHS-21) provides the detail adjustment pages supporting adjustments that are common between electric and gas operations. Exhibit No. ___ (JHS-22) provides the calculation of the revenue deficiency and the rate of return that is being requested by the Company, plus the detail for the conversion factor that is used to adjust for revenue sensitive taxes and fees. Exhibit No. ___ (JHS-23) provides an additional overview of all the adjustments as to whether they are contested or uncontested and how their net operating income, rate base and contribution to revenue deficiency compare between the Company and Commission Staff.

Q. Please explain the adjustments where the Company is in agreement with Commission Staff.

A. The uncontested adjustments and their impact on NOI or rate base are:

Adjustment	NOI	Rate Base
Actual Results of Operations	$117,427,311	$4,100,870,913
Adjustment 20.03-LSR Prepaid Transmission	(726,665)	110,846,093
Adjustment 20.05-Wild Horse Solar	179,073	(3,370,636)
Adjustment 20.06- ASC 815 (formerly SFAS 133)	108,519,513	
Adjustment 20.08-Remove Tenaska	30,284,100	(56,496,129)
Adjustment 20.09-Chelan Payments	(4,607,243)	135,630,302
Adjustment 21.01-Temperature Normalization	12,971,429	
Adjustment 21.03-Pass Through Rev/Exp	(306,445)	
Adjustment 21.07-General Plant Depreciation	688,453	(233,769)
Adjustment 21.08-Normalize Injuries and Damage	(725,618)	
Adjustment 21.09-Bad Debts	1,638,181	
Adjustment 21.12-Excise Tax & Filing Fee	(200,979)	
Adjustment 21.14-Interest on Customer Deposits	(47,149)	
Adjustment 21.16-Deferred G/L on Property Sales	(1,028,316)	
Adjustment 21.17-Property and Liability Ins.	(124,477)	
Adjustment 21.18-Pension Plan	(1,199,984)	
Adjustment 21.19-Wage Increase	(1,512,830)	
Adjustment 21.20-Investment Plan	(83,624)	

Q. Is this list of uncontested adjustments different than the list of uncontested adjustments that Mr. Martin presents in his prefiled response testimony?

A. Yes. The Company has accepted Commission Staff's Adjustment 21.19, Wage Increase, and Adjustment 21.20, Investment Plan. PSE's acceptance of the wage increase adjustment is discussed by Mr. Thomas Hunt in his prefiled rebuttal testimony, Exhibit No. __ (TMH-11T). The change to investment plan adjustment brings PSE in agreement with Commission Staff and is a direct result of the change to the wage increase adjustment. Adjustment 21.02, Revenue and Expenses, has been updated to incorporate the impacts on revenues for conditions agreed to in the settlement agreement for electric cost of service and rate design. These changes are discussed by Mr. Jon Piliaris in his prefiled rebuttal testimony, Exhibit No. ___ (JAP-20T).

Q. Are there adjustments where the Company and Commission Staff are in agreement as to methodology used to calculate the adjustment but that are not listed in the above table?

A. Yes. Although we are in agreement as to the methodology used to calculate several adjustments, these adjustments are dependent on other adjustments that are disputed, such as power costs, rate base and cost of capital. The difference related to Adjustment 20.11 Production Adjustment, is the result of differences in production related costs and rate base items included in other adjustments, and Adjustment 20.04, Montana Electric Energy Tax, is the result of updated rate year generation for the Colstrip facility from changes made to the rate year power cost forecast. The difference in Adjustment 21.05, Tax Benefit of Pro Forma Interest, is strictly the result of differences between the weighted average cost of debt and rate base.

VI. CONTESTED ADJUSTMENTS

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

A. Yes. The impact on net operating income and rate base for each of the Company adjustments is summarized on pages 2 through 5 of Exhibit No. ___ (JHS-19). Each of these adjustments is explained by reference to the actual adjustment page as listed below. The Company requests that the Commission accept the following adjustments as presented by the Company.

Power Costs-Adjustment 20.01

Mr. David Mills' prefiled rebuttal testimony describes the differences between the Company's power costs and the power costs proposed by Commission Staff and ICNU witnesses. Mr. Gould's prefiled rebuttal testimony discusses the differences between the Company, Commission Staff and ICNU for operation and maintenance costs that are associated with the Company's natural gas turbines.

Mr. Mills also points out Commission Staff witness Mr. Alan P. Buckley has made a duplicative adjustment to increase the BPA transmission credits, by $843,700. These credits reduce transmission expense related to the LSR prepaid transmission deposit. His calculation uses an outdated amortization schedule that was superseded by Data Request No. 195 submitted to parties on November 22, 2011. Mr. Applegate's adjustment for the LSR plant addition and Mr. Martin's adjustment for LSR prepaid transmission deposits rely upon PSE's Response to Commission Staff Data Request No. 195. This response increased the credits and the timing as to when credits flowed back to customers by $2,047,435 compared to the schedule Mr. Buckley was using. As Mr. Buckley's adjustment is duplicative it should be rejected by the Commission.

In addition to the adjustments discussed by Mr. Mills and Mr. Gould, ICNU's witness Mr. Deen proposes two additional adjustments related to power costs that are not appropriate for adjusting rates in this proceeding. These adjustments are listed in a table to his prefiled testimony, Exhibit No. ___ (MCD-1CT), page 2, and are labeled OATT Revenues, line 7, and FERC 557 Account/A&G, line 10.

Q. Why is the OATT Revenue adjustment not appropriate for setting rates?

A. The rates Mr. Deen used to make his proposed OATT adjustment are not known and measurable as they are still in litigation and are subject to refund. Mr. Deen provides the Company response to ICNU Data Request No. 2.49 as page one of Exhibit No. __ (MCD-4) that shows the amount being requested for OATT Revenues is a disputed amount being litigated at FERC. Mr. Deen then points to an October 20, 2011 FERC decision from that litigated docket which he states "accepts" PSE's proposed schedules. What Mr. Deen fails to point out in that October 20, 2011 FERC decision is that the rates that were "accepted" are subject to refund if the final Order from FERC approves rates different than the Company's filing. As stated in the FERC Order:

> The Commission orders:
>
> (A) Puget's proposed Schedules 3 and 13 are hereby accepted for filing and suspended for a five-month period, to become

> effective January 5, 2012, *subject to refund,* as discussed in the body of this order.[4]

Accordingly, the Washington Commission should reject Mr. Deen's adjustment.

Q. Why is Mr. Deen's FERC 557 Account/A&G adjustment not appropriate?

A. On page 12 of Mr. Deen's prefiled testimony he states that he reviewed Account 557 subaccounts over the last five years and that the pattern in the subaccounts shows significant variation through the years. However, Mr. Deen's workpapers show that he was actually reviewing only select workorders that were charged to Account 557. He fails to mention that the total account balance for Account 557 is actually growing each year for the last five years as shown below.

2006	2007	2008	2009	2010
6,291,538	6,584,001	7,517,003	8,224,197	9,359,135

This is not an unexpected outcome as regulations, contracts and other miscellaneous costs associated with power costs have grown from $6.3 million in 2006 to $9.4 million in 2010. The Commission should reject this part of the adjustment for this reason alone, however, Mr. Deen also has several errors in his calculation. He fails to recognize that the test year Account 557 is restated and

[4] FERC Docket No. ER11-3735-000, order issued October 20, 2011, page 24 (emphasis added).

has pro forma adjustments for various expenses. The amount allowed in rates for this account with a test year 2006 was $6.8 million versus the $6.3 million booked and used by Mr. Deen in his five year average. The amount in Account 557 being proposed by the Company in this filing using 2010 as the test year is $6.6 million as shown in Exhibit A-1 of the PCA Exhibits, Exhibit No. ___ (JHS-25), versus the $9.4 million used in Mr. Deen's five year average. As Mr. Deen's adjustment is based on erroneous and irrelevant information, the Commission should reject this adjustment.

Mr. Deen goes on to suggest that legal fees associated with a BPA rate case that had been misclassified to account 557 and which are now being restated to Account 923 should also be averaged over five years. His stated reason on page 12 of his testimony is that there has been an extraordinary high level of ratemaking and legal activity by BPA related to various activities and that a five year average is a more appropriate level of expense for prospective ratemaking purposes. Mr. Deen provides no explanation as to why this averaging is a more appropriate level of expense for ratemaking, or proof that BPA or other regulatory legal actions will be less over the next few years, or even if it was higher in the test year versus other years. As it turns out, the 2010 test year is the lowest year in the three years ended 2010 for total legal cost. As with any legal expense, the action that caused the expense will not be repeated in the future; however, new legal expense requirements will take its place. The Company must be allowed to recover its legal costs incurred in protecting its customer's rights and benefits. Mr. Deen's unsupported adjustment should be rejected.

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

A. Yes. As described by Company witness Mr. Mills, PSE has lowered the storage rental fees for the Jackson Prairie facility to reflect the most recent signed agreement. With this change, PSE and Commission Staff agree on the amount of rental fees for Jackson Prairie. However, the treatment of these storage rental fees for the Jackson Prairie facility for PCA purposes remains in dispute. PSE is proposing that these rental fees be included as a variable cost item when calculating the PCA deferral to align with the variable treatment received for the storage rental revenues that are included in the Company's purchased gas adjustment mechanism. Mr. Martin argues that these costs will not vary, yet he contradicts himself in the same section of his testimony. In his testimony he uses the fact that these fees are changing to propose his pro forma adjustment to lower the fees in the rate year. The fact that these fees are changing demonstrates that they are properly classified as variable costs. Mr. Clay Riding provides background on the Jackson Prairie storage and how the fees vary over time in his prefiled rebuttal testimony, Exhibit No. ___ (RCR-4HCT). The Company continues to request that the Commission approve treating these fees as variable costs in the PCA.

In conclusion, including the changes made to this adjustment in rebuttal as discussed by Mr. David E. Mills and Mr. Wayne R. Gould, the impact on net operating income for this adjustment is now an increase of $111,802,838 compared to the $100,033,495 included in the supplemental filing.

Q. Please continue with your discussion of contested adjustments.

A. The next adjustment is as follows:

Lower Snake River Project, Adjustment 20.02

As discussed in the Prefiled Rebuttal Testimony of Roger Garratt, Exhibit No. ___ (RG-16CT), this plant will be put in-service during February 2012. The Company's pro forma adjustment in this case is consistent with the treatment of new resources in the Company's 2007 general rate case, where the full value of the new plant was included in the revenue deficiency as a pro forma adjustment. Please see my earlier discussion on pro forma adjustments as to why the Company feels this adjustment is appropriate and should be accepted by the Commission.

Q. Please discuss the differences between Commission Staff and the Company in calculating this pro forma adjustment.

A. The first difference between the Company and Commission Staff is that the Company has included the estimated cost to complete the plant by February 2012 in its determination of rate base. The plant value PSE uses in this adjustment is the same plant value that Mr. Martin uses when he calculates the LSR Deferral. Mr. Martin's work papers supporting the deferral adjustment are included as Exhibit No.___ (JHS-26) which I discuss later in my testimony. Mr. Applegate only includes actual costs, included in construction work in progress, plus the currently known and measurable contract costs of this plant through October

2011. This difference in plant value also impacts accumulated depreciation, deferred taxes, depreciation expense and property insurance.

In the Company's rebuttal adjustment, the line item labeled transmission expense, shown on line 17, is also being updated. During review of this adjustment for rebuttal it was found that $420,203 of costs associated with LSR transmission was picked up on this adjustment and was also included in the LSR Transmission Deposit, Adjustment 20.03. That amount has been removed from line 17 in this adjustment.

The second difference between the two adjustments is that Commission Staff removes property taxes associated with this plant addition. Mr. Marcelia discusses property taxes and why this adjustment is not appropriate in his prefiled rebuttal testimony, Exhibit No. ___ (MRM-14T).

Q. Did any other parties have an adjustment for this plant addition?

A. Public Counsel and ICNU argue that this resource is imprudent. Mr. Garratt and Ms. Seelig discuss the shortcomings of their arguments and recommend that the Commission rule that this plant was prudently reviewed and constructed.

Q. What is the impact on net operating income and rate base for the Company's pro forma adjustment related to LSR?

A. Including the updates resulting from this plant resource going into service in February 2012, versus the original assumption of April 2012, this adjustment decreases net operating income by $37,275,750 and increases rate base by $664,324,546 as compared to decreasing net income by $39,435,507 and increasing rate base by $687,710,765 in the supplemental filing.

Q. Please continue with your review of the contested adjustments.

A. The following adjustments are also contested:

<u>LSR Prepaid Transmission Deposit, Adjustment 20.03</u>

This adjustment is not contested, however, as described in my prefiled direct testimony Exhibit No. ___(JHS-1T), PSE filed an accounting petition in May of 2010 requesting approval of specific regulatory treatment of a prepaid transmission deposit made to BPA related to the LSR Phase 1 Wind Project, Docket No. UE-100882. No party in this proceeding has contested the Company's adjustment, and Commission Staff's adjustment for this transmission deposit is the same as the Company's. Accordingly, PSE requests that the Commission expressly accept the Company's proposed regulatory treatment of this prepaid deposit as requested in this proceeding and in its still pending accounting petition.

<u>Montana Electric Energy Tax, Adjustment 20.04</u>

The adjustments of the Company and Commission reflect differing assumptions regarding the amount of energy being generated at Colstrip in the respective power cost adjustment. The methodology to calculate the adjustment is not in dispute. This adjustment reflects the changes to rate year generation discussed in the prefiled rebuttal testimony of Mr. David E. Mills. This adjustment now results in a decrease to net operating income of $103,079 compared to the $100,185 included in the supplemental filing.

<u>Storm Damage, Adjustment 20.07</u>

The Company's adjustment is presented in the same manner and using the same methodology that was approved by the Commission in the Company's 2004 general rate case and accepted in each general rate case since then. Under previous Commission determinations, PSE is allowed to defer catastrophic storm damage that meets the IEEE standard and that exceeds an annual $8 million threshold. This deferred catastrophic storm damage is amortized over four years, except in extraordinary cases—such as the Hanukkah Eve storm in 2006—in which the Commission allowed for a longer amortization period of 10 years at Commission Staff's request. Catastrophic storm damage below the $8 million threshold and normal storm damage that does not meet the IEEE catastrophic storm standard are normalized over a six-year period. Currently, the normalized storm damage amount built into rates is $8 million.

Q. Is Mr. Applegate's characterizations of the Company's Storm Damage adjustment accurate?

A. No. He has several errors in his discussion of this adjustment. The first error is his discussion of the $8 million annual expense associated with storm damage. He is correct that this amount is based on an average of six years for storm damage that is charged to the income statement. He is incorrect that any storm damage in excess of $8 million is deferred. As I discuss later, it is a common occurrence for storm damage expense to exceed this amount in a given year. The Company defers only the catastrophic storm damage costs that meet the IEEE standard and that exceed a threshold of $8 million. IEEE standard costs are discussed in more detail in Ms. McLain's prefiled rebuttal testimony, Exhibit No. ___ (SML-7T). There is a significant amount of storm damage that does not meet the IEEE standard for catastrophic storms and these costs are charged directly to expense.

Q. Is Mr. Applegate correct in stating that Docket UE-072300 gave rise to the three recovery mechanisms appearing in this adjustment?

A. No. Docket UE-072300 set the current deferral threshold of $8 million for IEEE defined catastrophic storms, and it is the docket where the Commission approved recovery of the Hanukkah Eve storm costs over 10 years. It is not the origin of the deferral mechanism for catastrophic storms. In Docket UE-921262, Mr. Thomas Schooley of Commission Staff proposed normalizing storm damage costs over a six year period, and that extraordinary property damage be amortized over a six-year period. Mr. Schooley proposed to define "catastrophic event" as one affecting 25% or more Company customers, occurring infrequently, and affecting a wide geographic area. His proposal was approved by the Commission and this definition of catastrophic storm was used until 2004. The Commission approved the current definition for catastrophic storms using the IEEE Standard in Docket UE-040641 based on a joint proposal of the Company and Commission Staff. This definition is explained in more detail in the prefiled rebuttal testimony of Ms. Susan McLain, Exhibit No. ___ (SML-7T).

From 2001 through 2006 a three-year amortization period was used for storm deferrals. The current four-year amortization period was adopted in the 2007 GRC.

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.

Q. Are there other types of storm events for which PSE incurs costs other than catastrophic storms?

A. Yes. As stated earlier, there are costs incurred for other storm events that do not meet the IEEE standard for catastrophic storms. Those costs are referred to as normal 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 standard. These normal storm costs are part of the normalization calculation which uses a six-year average. As can be seen on the Storm Damage adjustment, Exhibit No. ___(JHS-20), page 8 of 14, lines 3 through 8, the Company has experienced storm damage costs greater than $8 million that were not deferred in four of the last six years. These amounts include (i) the storm costs that meet the IEEE standard, but were less than the deferral threshold; and (ii) the normal storm costs that do not meet the IEEE standard.

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 threshold. This annual threshold is determined and approved in a general rate case. The annual threshold is currently $8 million and is based on the 6 year normalized normal storm expense in a given proceeding. Only when IEEE storm expenses exceed the $8 million threshold are they allowed to be deferred. Ms. McLain also describes other costs that are related to IEEE-qualifying storms that are not deferred in her prefiled rebuttal testimony, Exhibit No. ___(SML-7T). The Company is requesting that the Commission allow the current $8 million threshold to remain in effect.

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 storm deferral mechanism.

Type of Expense	Mechanism		
	Normalize	Defer & Amortize	
	6 Years	4 Year(*)	10 Year(*)
Non-Qualifying	X		
IEEE qualifying below threshold	X		
IEEE qualifying above threshold		X	X

(*) The length of the amortization period has varied over time since UE-040641 when the IEEE qualifying provisions were adopted as the definition of a catastrophic storm. The length of the amortization period has been agreed to during the course of subsequent proceedings based on intervenor proposals made primarily to lessen the rate impact of storm deferrals.

Q. Does Mr. Applegate propose a new definition of catastrophic storm damage?

A. No. Mr. Applegate recommends recovery of costs through a deferral for "limited catastrophic circumstances". Mr. Applegate fails to define what event would qualify as a "limited catastrophic circumstance" in his prefiled testimony. When asked in a data request how his definition of "limited catastrophic circumstances" would be determined his response was;

> If a year's combined storm damage expense exceeds 233% (or 2 times 7 years divided by 6 years) the 6-year storm damage average, Mr. Applegate would recommend deferred recovery of the portion that exceeds the 6-year average. In Mr. Applegate's view, this treatment would mitigate rate impacts without distorting the 6-year average.

Mr. Applegate provides no basis as to why this calculation is appropriate other than it is his "view" this would not distort the six-year average. To see the impact of this definition the Company recalculated Storm Damage expense using the last six years as the data source. Under Mr. Applegate's proposal, the amount of normal storm damage expense that would be built into rates in this proceeding would be approximately $17 million. His threshold for deferral would be in excess of $39 million (2.33 * $17 million), rather than the $8 million deferral currently approved by the Commission. Obviously, if storms up to that level of cost were to occur there would be a substantial impact on the six-year average. See Exhibit No. ___ (JHS-27) for the calculations used in this explanation.

Q. Does the Company agree with Mr. Applegate that his proposal does not have much of an impact on risk allocation?

A. No. In effect he has added a risk of $20 million dollars of after tax volatility (($39m-$8m)*.65) to the Company's earnings yet he states it is unlikely that his recommendation will have much effect on risk allocation. This statement seems disingenuous based on Commission Staffs' position in the pipeline integrity program ("PIP") filing, Docket No. UG-110723, where Commission Staff argues that the Company's return on equity should be adjusted down if it is allowed to collect an amount through the PIP that is less than 10 percent of the amount at issue in the storm deferral.

Q. Are there any other concerns that the Company has with Mr. Applegate's proposal for storm damage?

A. Yes. Mr. Applegate discusses how he would still allow the Company to recover the deferred storm damage costs that had been approved in prior general rate cases. However, for storm damage costs that have been incurred and deferred under the storm damage mechanism allowed in that same general rate case he would change how these costs are treated and proposes to use those costs in determining his new level of storm damage expense. This change in the handling of these costs would require the Company to write-off the previously deferred balances of approximately $14 million. Mr. Applegate does not contest these costs as being imprudent as he uses them in his proposed methodology to determine normalized storm damage costs. He provides no reason as to why his proposal should retroactively change an accepted methodology of handling storm damage costs. Mr. Applegate testifies that this is not a disallowance; however, contrary to his testimony, it is a disallowance.

Q. Does the Storm Damage adjustment as presented by the Company meet the Commission's previously approved methodology for handling storm damage?

A. Yes. The deferred amounts that are shown on Exhibit No. ___ (JHS-20), page 8 of 14, lines 22 through 26, are not normal operating expenses. They are costs incurred for storm events that meet the IEEE standard for catastrophic storms *and* have exceeded the annual threshold of $8 million for IEEE standard storm costs. The six-year normalization portion of the Company's adjustment, shown on lines 3 through 8 on the same page, already accomplish Mr. Applegate's goal that current rates should reflect normal storm costs.

Q. Should the Commission adopt Commission Staff's adjustment and recommendations for altering PSE's storm deferral mechanism?

A. No. The previously approved mechanism for deferring catastrophic storm costs already achieves the goals discussed in Mr. Applegate's response testimony and is based on a well documented methodology as to how the costs are to be treated. The IEEE standard provides a sound basis for determining that only costs that are not normal storm costs are deferred, and it allows a normal amount of storm damage to be built into current rates. Additionally, deferrals are amortized over a multi-year period determined in a general rate case based on the size of the deferral and the resulting rate impacts. Arbitrarily increasing the amortization period to seven years is unwarranted and unnecessary.

For the reasons stated above the Commission should accept the Company's adjustment, which increases net operating income by $1,349,514 and remains unchanged from the supplemental filing.

Q. Please continue with your review of the contested adjustments.

A. The following adjustments are also contested:

<u>Chelan Initiation Payment, Adjustment 20.09</u>

The Company and Commission Staff do not have a disagreement as to how this adjustment is calculated; however, Public Counsel witness, Ms. Crane, appears not to understand the terminology used, redefines "net of tax rate of return" and erroneously calculates an adjustment to the interest accrued on the contract initiation payment and the related impact on power cost amortization based on her incorrect definition.

Q. What is meant by the term "net of tax rate of return"?

A. The net of tax rate of return is the Company's allowed rate of return with the interest component of the return reduced by 35%, the Company's statutory federal income tax rate. The product of the equity component embedded in the rate of return times rate base is the amount of money that the Company needs to receive to cover its cost of equity and is an after tax amount. The net of tax interest component of the rate of return times rate base is a short cut methodology to insure the customer is only being charged for the actual interest embedded in the rate of return. Without this calculation the customer would be charged interest plus taxes instead of just the interest cost. In a full revenue deficiency calculation, which is filed with a general rate case, this tax benefit of interest is calculated in the Tax Benefit of Pro forma Interest Adjustment. In this proceeding, this is Adjustment 21.05 which I discuss later in my testimony.

Q. **Why does the Company gross up the interest calculation for federal taxes after multiplying the Chelan initiation payment by the net of tax rate of return?**

A. This calculation adjusts the interest component of the return back to the actual interest amount so that a dollar received from the customer offsets a dollar of interest. It also adjusts the equity component of the return for the taxes that will have to be paid when that return is billed to customers. As I mentioned earlier, the product of the equity component of the rate of return times rate base is the amount of money that the Company needs to receive to cover its cost of equity and is an after tax amount. To actually have that amount of money available for the equity component, this product must be grossed up for taxes.

Q. Is Ms. Crane correct that the Company is earning a return on the taxes that have been recorded for the Chelan initiation payment?

A. No. The amount to be included in rate base for the Chelan initiation payment is shown net of deferred taxes. Ms. Crane acknowledges this in her testimony. When the interest is recorded on the Chelan initiation payment, the offsetting entry is interest income on the income statement. As the Company has not actually received this revenue, the revenue is not yet a taxable item. To record the taxes that will be paid when the dollars are collected from customers, the Company charges deferred tax expense on the income statement and credits a deferred tax liability on the balance sheet to normalize the taxes associated with the interest income. When the two balance sheet accounts are netted against each other, the interest on the Chelan initiation payment and the deferred tax liability, the balance included in rate base is net of federal taxes. I have presented Exhibit No. ___(JHS-28) which demonstrates that the Company has booked the deferred tax liability and that it is equal to 35% of the Chelan deferred carrying charges. This is common ratemaking practice contrary to Ms. Crane's opinion.

Q. **Is Ms. Crane correct in stating that $77.2 million of the $141.8 million associated with the Chelan payment is interest?**

A. No. The principal was $89 million so deducting that amount from $141.8 million calculates the amount of $52.8 that must be collected from customers to cover the carrying costs. Deducting the deferred taxes that are included in the $52.8 shows that the interest is around $34 million.

Q. Did Public Counsel or its witness ask any data requests of the Company as to why this account was treated in the manner it was?

A. No.

Q. Please summarize your analysis of the issues Ms. Crane has raised.

A. Ms. Crane's perceived double recovery is not an issue. Her adjustment has errors in its calculation and the adjustment is duplicative of the entry that is already reflected on the Company's books plus shown on the Company's adjustment. The Commission should approve the Company's and Commission Staff's adjustment for this item.

Q. Please continue with your review of the contested adjustments.

A. The following adjustments are also contested:

<u>Regulatory Assets and Liabilities, Adjustment 20.10</u>

This pro forma adjustment adjusts certain production related regulatory assets and liabilities that are recovered through the PCA Mechanism.

Q. Please identify the parties that propose adjustments to regulatory assets and liabilities that are different than the Company's.

A. The only party proposing changes to this adjustment is Commission Staff. The following is an overview of Commission Staff witness Mr. Roland C. Martin's proposed adjustments to PSE's filed adjustment:

<u>Colstrip 1&2 (WECo) Coal Dedication Fee:</u>

PSE made a $5 million dedication fee payment to Western Energy Company ("WECo") upon the signing of the Colstrip Unit 1 and 2 Coal Purchase and Sale Agreement ("CPSA") in March 2007, which is recorded as a prepayment on the balance sheet. This amount has been included in PSE's working capital since that time.

The dedication fee was paid to WECo so that it would limit coal sales to third parties in order to reduce long-term coal costs to PSE and its customers. By limiting WECo's coal sales to other parties the amount of coal available under the CPSA is greater, and the annual cost of overburden removal, a major cost of mining the coal, is reduced. The contract term for the CPSA is January 1, 2010 through December 31, 2019[5].

Prior to the execution of the CPSA, WECo had already entered binding contracts to sell coal to third parties through December 31, 2010, which overlaps with the first year of the CPSA term. These binding contracts with third parties occurring in the first year of the CPSA term do not allow WECo to limit coal sales.

Therefore, the dedication fee only relates, and should only be applied, to coal

[5] 2019 has been used as the end of the contract because that is the first opportunity for either the Buyer or Seller to terminate.

sales to PSE on and after January 1, 2011. This is the start of the time period over which the dedication fee applies and provides benefits to customers.

Q. What is Commission Staff's proposal for this payment?

A. Commission Staff witness Mr. Martin proposes to add one year to the amortization period to match amortization of the dedication fee to the full contract term of ten years by pushing the additional year of amortization back into 2010. Mr. Martin raises concerns about appropriate matching in his testimony, however, he is applying the wrong standard for matching. He actually creates a mismatch by using the time period of the contract term—2010 through 2019—rather than the time period over which the dedication fee provides benefit—2011 through 2019. He tries to justify this adjustment by reference to existing regulatory assets and liabilities. However, the underlying contracts for these referenced regulatory assets and liabilities do not have comparable structures or features to the CPSA. For those contracts the benefit period is the same as the contract period, therefore they provide no basis for comparison.

Q. How has the Company treated this cost for financial purposes?

A. For financial and regulatory purposes, PSE recorded this as a prepayment on the balance sheet and began amortizing the dedication fee in 2011 over the period during which PSE and its customers receive the benefit: 2011 through 2019. The Company cannot change this prepayment and expensing for financial purposes as it is the correct recording of this cost. Mr. Martin's proposal actually creates a mismatch between benefits received versus cost of the benefit, and between financial accounting and regulatory recognition. This proposal, if accepted by the

Commission, would require the Company to write-off one tenth of this retention value, which is $500,000, even though customers are receiving the full benefit over the years 2011 through 2019. The Company has recorded the cost correctly for financial reporting purposes, and Mr. Martin has not provided any valid reason it should be treated differently for regulatory purposes. Accordingly, the Commission should reject Mr. Martin's proposal.

Contract Major Maintenance:

In its original filing, the Company includes amortization and deferrals of major maintenance associated with Long Term Service Agreements ("LTSA") and Contract Service Agreements ("CSA") at their test year amounts with inclusion in the baseline rate as a variable cost. These particular deferrals are associated with major maintenance that is expected to occur approximately every two years. PSE proposes this methodology as a way to recognize that, although the majority of the test year regulatory assets will be fully amortized by the rate year, as discussed by Mr. Gould in his prefiled rebuttal testimony Exhibit No. ___ (WRG-1T), it is assumed that there will be another major maintenance event that coincides with the end of their amortization period. PSE has used the test year amortization and rate base amounts as the expected cost of the next major maintenance.

Commission Staff objects to this treatment and contends that the amortization expense and rate base balances of existing approved test year regulatory assets should be treated like all other power costs and regulatory asset related rate base items, *i.e.*, the rate year expenses and balances should be used for ratemaking purposes in the baseline rate.

In Commission Staff's response to PSE Data Request No. 010, Mr. Martin confirms his understanding that the amortization periods for this type of cost deferral are determined based on the estimated time interval between like events and the fact that a subsequent event will occur that impacts the rate year. *See* Exhibit No. (JHS-29). Despite acknowledging this to be true, Mr. Martin's adjustment does not try to achieve his stated goal that "rate year expenses and balances should be used for ratemaking purposes" as he does not include the rate year events that will follow the expiring major maintenance amortization.

Mr. Martin compounds this problem by proposing that for events that occur between rate cases PSE must still amortize the deferral, and should not be allowed to include the amortization expense or the unamortized deferral balance in rate base for setting rates without filing a separate accounting petition. The Company respectfully disagrees with Mr. Martin on this issue. The Company has followed GAAP in deferring and starting the amortization of these costs. As to the rate base treatment, the Company is appropriately asking for that regulatory treatment for major maintenance deferrals accounted for under GAAP in this proceeding. There is nothing in the Commission rules that says a Company may only request regulatory treatment for cost recovery with an accounting petition, and based on recent history, several of the Company's accounting petitions are not resolved until a general rate case filing.

For example, the Company filed an accounting petition, Docket No. UE-100882 regarding the LSR transmission payments which I discussed earlier. Commission Staff has conducted some informal review in this Docket but has not taken any action on that accounting petition. This accounting petition had been pending for a year when PSE filed this rate case. As this was an unresolved matter, PSE requested the same regulatory treatment for these prepaid transmission costs in this case as it had requested in the accounting petition. Commission Staff now agrees with the Company's treatment of these transmission payments in this general rate case filing. *See* my adjustment JHS-20.03 and Staff witness Mr. Martin's adjustment RCM-2 page 2 adjustment 13.03.

Q. Does Mr. Martin's proposal allow the Company to recover its costs for contracted major maintenance?

A. Mr. Martin's proposed adjustment makes it unlikely that PSE would ever recover its costs associated with contracted major maintenance events that are being amortized over two years. In a historical test year state with an eleven month adjudicative proceeding, the beginning of the test year is at least 26 months—a 12 month test year, 3 plus months for preparation of the case, and 11 months for the adjudicative proceeding—before the start of the rate year. Any contract major maintenance that is completed prior to the test year and up to the beginning of the third month of the test year would be eliminated from the Company's cost profile per Mr. Martin's adjustment. Depending where in the rest of the test period contract major maintenance occurs, and amortization of the deferral begins, only the remaining few months of the amortization would be included as a rate year expense. This effectively denies the Company a substantial portion of its costs to maintain these plants. Mr. Martin's adjustment should not be accepted by the Commission.

The Commission should accept PSE's adjustment for contract major maintenance as filed as it allows PSE to follow ASC 980 for financial reporting purposes and for recovery of these costs in rates. PSE believes this matches the intent of the Commission upon accepting in principle the deferral methodology in the 2009 general rate case.

Q. Please continue with your review of the contested adjustments.

A. The following adjustments are also contested:

REC Sales and LSR Deferral

Commission Staff presented adjustments for REC Sales and LSR Deferral on the Regulatory Asset and Liability adjustment. REC Sales are covered in the Multiparty Settlement[6] and should be removed from this Commission Staff adjustment if the Commission accepts the settlement. The Company presents the LSR Deferral as a separate adjustment for calculating the revenue requirement so that all the costs are identified. I will discuss this adjustment, LSR Deferral, Adjustment 20.12, later in my testimony.

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[6] Multiparty Settlement Re: Electric Rate Spread, Electric Rate Design and Renewable Energy Credit Tracker.

Production Adjustment, Adjustment 20.11

The Company and Commission Staff agree as to the methodology used to determine this adjustment. The difference on expense and rate base items are based on the production-related adjustments included in other adjustments such as the LSR adjustment. This adjustment will have to be updated based on final Commission determinations related to those adjustments.

LSR Deferral, Adjustment 20.12

The purpose of this adjustment is to include the estimated rate year amortization expense and net rate base amount for deferred costs associated with Phase 1 of PSE's Lower Snake River wind electric generation project. The costs of the project from the projected in-service date of February 11, 2012 to the date rates will become effective for this proceeding, May 14, 2012, will be deferred under RCW 80.80.060(6), which allows cost deferral for renewable resources like LSR.

Q. Why does the Company include this adjustment in this proceeding?

A. Similar to Commission Staff, PSE includes the estimated deferred costs of LSR Phase 1 to avoid having to carry the deferral until a subsequent general rate case. The current general rate case proceeding provides the earliest opportunity for Commission consideration of the deferrals.

Other parties were aware that PSE would be making this adjustment and an example of the adjustment was sent to parties in PSE's response to WUTC Staff Data Request No. 197, dated November 22, 2011.

Q. What is the proposed amortization period for the LSR project deferred costs?

A. PSE and Commission Staff both agree that a reasonable amortization period would be four years from the date the rates in this docket become effective.

Q. Does Commission Staff dispute any aspect of the estimated amounts used in the LSR adjustment provided by the Company?

A. Yes. As discussed earlier in my testimony, Commission Staff excludes the estimated property tax amount although it is certain that PSE will pay property tax on LSR, and tax is expressly listed in RCW 80.80.060(6) as a cost that may be deferred. Both Mr. Matthew R. Marcelia, in prefiled direct and rebuttal testimony, and I discuss property taxes and why excluding current property taxes is not appropriate.

Q. Do you have other concerns regarding Commission Staff's calculation of the LSR Deferral?

A. Yes, as I previously discussed there is a major inconsistency between the Commission Staff adjustment for the LSR plant addition and this adjustment for the LSR Deferral. As previously mentioned, Commission Staff witness Mr. Martin calculates the deferral using a gross plant balance equal to the total project cost, which is consistent with PSE's calculation. However, Commission Staff witness Mr. Applegate uses only the CWIP balance plus remaining contractual obligations as of October 31, 2011 as the gross plant balance for the LSR plant adjustment.

Q. Your ratebase amount shown in Exhibit No. ___ (JHS-20), page 20.12, is $13,105,765 and the amount shown on Mr. Martin's Exhibit No. ___ (RCM-2), page 15, is $12,682,422. Why are these amounts different if you are both using the same plant value as of February 2012?

A. The difference is the property tax that Mr. Martin removes from the deferral amounts. Please see Exhibit No. __ (JHS-26) for the detail behind these two rate base amounts. Page one of the Exhibit is the Company calculation of the amortization and rate base impact. The amount shown on line 13 in the Rate Year column is the average of monthly average of the deferred costs during the rate year. Page two of the exhibit shows the amortization of the costs that are expected to be deferred from February to May 13, the expected date for rates to be effective from this Docket. The amount shown on line 5, column (b), is the total of the deferrals that is expected in May, 2012 and comes from page 3, line 20, the Total column. The amount on line 16, column (c), is the rate year average of monthly averages which is shown on page 1. Page 3 shows the Company calculation of the amount to be deferred for each month and the expected deferral as of May on line 20, Total Column, which carries forward to page 2, line 5, column (b). Page 4 of the exhibit is Mr. Martin's Exhibit No. ___ (RCM-2), page 15, which shows his rate base impact on line 23, Rate Year column. Page 5 is his calculation of the amortization of deferred costs and the line numbers are equivalent to the Company's calculation. Page 6 shows the costs that Mr. Martin believes will be deferred over the same time period as used by the Company and the line numbers are equivalent to the Company's line numbers. As shown on page 6 all the costs are the same as shown on page 3 of this exhibit other than property taxes shown on line 11 for both pages. On line 1 of pages 3 and 6 of this exhibit is the amount of LSR in-service costs, $667,299,318, which is the average of monthly average of the first full year of service net of depreciation and deferred taxes. This is based on the in-service costs as of February, 2012.

Q. What amounts should be approved by the Commission for the LSR Deferral in this proceeding?

A. The Commission should accept PSE's proposed adjustment for the LSR deferral as it follows the intent of RCW 80.80.060 which allows the deferral of costs associated with this type of plant. This adjustment decreases net operating income by $3,772,213 and increases electric rate base by $13,105,765.

Q. Please continue with your review of the contested adjustments.

A. The following adjustments are also contested:

<u>Revenues and Expenses, Adjustment 21.02</u>

Adjustment 21.02, Revenue and Expenses, has been updated to incorporate the impacts on revenues for conditions agreed to in the settlement agreement for electric cost of service and rate design. These changes are discussed by Mr. Jon Piliaris in his prefiled rebuttal testimony, Exhibit No. ___ (JAP-20T).

Federal Income Tax, Adjustment 21.04

Mr. Michael J. Stranik discusses the differences between the Company and other parties. Mr. Marcelia discusses why these adjustments should not be made in his prefiled rebuttal testimony, Exhibit No._____(MRM-14T).

Tax Benefit of Pro forma Interest, Adjustment 21.05

Mr. Martin, in his prefiled testimony, lists this adjustment as contested. The methodology of the calculation is not disputed between the Company and Commission Staff. The difference between the Company and the Commission Staff results from the different amounts used for rate base and weighted average cost of debt used in calculating the amount of interest eligible for a tax deduction. Based on the Commission decisions in this proceeding this adjustment will need to be updated to reflect the approved rate base and interest costs.

Operating Expenses, Adjustment 21.06

Mr. Michael Stranik discusses the differences between the Company and Commission Staff for this adjustment. *See* Exhibit No. ___ (MJS-10T).

Incentive Pay, Adjustment 21.10

Mr. Thomas Hunt and Mr. Michael Stranik discuss the differences between the Company and Commission Staff for this adjustment. *See* Exhibit No ___ (TMH-11T) and Exhibit No. ___ (MJS-10T).

Property Taxes 21.11

Mr. Marcelia discusses why the Company's adjustment is appropriate for determining property tax expense and how the Company's adjustment uses the same methodology the Commission accepted for many years prior to the 2009 general rate case filing in both his prefiled direct testimony, Exhibit No. ___ (MRM-1T) and his prefiled rebuttal testimony, Exhibit Nos. ___ (MRM-14T). I will discuss why Mr. Applegate's proposed adjustment violates FERC accounting instructions.

Q. Why are FERC accounting instructions relevant to Mr. Applegate's property tax adjustment?

A. The Company must comply with WAC 480-100-203 and 480-90-203. Both of these say the same thing except for the reference to type of energy.

> (1) Electric utilities in the state of Washington must use the uniform system of accounts applicable to major and non-major electric utilities as published by the Federal Energy Regulatory Commission (FERC) in Title 18 of the Code of Federal Regulations, Part 101. Information about the Code of Federal Regulations regarding the version adopted and where to obtain it is set out in WAC <u>480-100-999</u>, Adoption by reference.
>
> (2) Electric utilities having multistate operations must maintain records in such detail that the costs of property located and business done in the state of Washington can be readily ascertained in accordance with geographic boundaries.
>
> (3) Any deviation from the uniform system of accounts, as prescribed by the FERC, will be accomplished only after due notice and order of this commission.
>
> (4) This rule does not supersede any commission order regarding accounting treatments.

Q. How does Mr. Applegate's property tax adjustment violate the FERC accounting instructions?

A. Mr. Applegate is proposing that the Commission adopt cash accounting for purposes of determining property taxes. This is the same proposal Commission Staff made in the Company's last general rate case. In that proceeding the Commission veered from its prior course on the treatment of property taxes and accepted Commission Staff's proposal, as it relates to PSE, for the first time. As Mr. Marcelia points out in his prefiled rebuttal testimony, Mr. Applegate's adjustment does not even meet his stated goal of providing for cash accounting. Even ignoring this error in Mr. Applegate's proposal, the adjustment still violates General Instruction 11 of the FERC accounting instructions which is entitled, "Accounting to be on Accrual Basis". Section A of this instruction states:

> The utility is required to keep its accounts on the accrual basis. This requires the inclusion in its accounts of all known transactions of appreciable amount which affect the accounts. If bills covering such transactions have not been received or rendered, the amounts shall be estimated and appropriate adjustments made when the bills are received.

This is exactly what the Company must do for property taxes. As explained by Mr. Marcelia, property taxes are based on a given year's property values and billed the next year. The Company is required for financial and regulatory accounting purposes to accrue for this liability. This accrual is not just an unsupported estimate made by the individual making the adjustment. It must meet standards of reasonableness, and it is reviewed by other personnel in the Tax Department and the Company's outside auditors for reasonableness.

Q. Please elaborate on your concerns regarding Commission Staff's proposal that results in violating the FERC's accounting instructions?

A. FERC has accounts for all sorts of transactions that are not recoverable in rates. However, no one is disputing that property taxes are a valid expense for rate recovery. The dispute is, what is the correct amount. Mr. Applegate is creating a mismatch between Company assets in the test year and the cost associated with those assets. He plainly states this fact in his testimony and then proceeds to advocate for an unacceptable method of accounting for determining rate recovery for these costs. Commission Staff's adjustment raises a myriad of questions and creates ambiguity as to when regulatory accounting applies and when it does not apply. As Mr. Marcelia points out, and I concur, there are hundreds of transactions that require accrual and that are based on estimates. Should all of these estimates be switched to cash accounting? The Company does not believe so. To do so would do away with both financial and regulatory accounting standards and would create a mismatch as to what a company must record on its books versus what would be allowed for ratemaking.

The Company requests that the Commission reconsider its last decision concerning property taxes and accept the Company's proposed adjustment which is calculated using the same methodology accepted in numerous Company regulatory proceedings before this Commission.

Q. Please continue with your review of the contested adjustments.

A. The following adjustments are also contested:

Director and Officers Insurance, Adjustment 21.13

Mr. Michael Stranik discusses the differences in the positions of the Company and Commission Staff for this adjustment. *See* Exhibit No. ___ (MJS-10T).

Rate Case Expenses, Adjustment 21.15

Mr. Michael Stranik discusses the differences in the positions of the Company and Commission Staff for this adjustment. *See* Exhibit No. ___ (MJS-10T).

Employee Insurance, Adjustment 21.21

Mr. Thomas Hunt and Mr. Michael Stranik discuss the differences in the positions of the Company and Commission Staff for this adjustment. *See* Exhibit No. ___ (TMH-11T) and Exhibit No. ___ (MJS-10T).

Working Capital, Adjustment 21.22

Mr. Matt Marcelia and Mr. Michael Stranik discuss the differences in the positions of the Company, Commission Staff, Public Counsel and ICNU for this adjustment. *See* Exhibit No. ___ (MRM- 14T) and Exhibit No. ___ (MJS-10T).

The adjustments of the Company and Commission reflect differing assumptions regarding the amount of energy being generated at Colstrip in the respective power cost adjustment. The methodology to calculate the adjustment is not in dispute. This adjustment reflects the changes to rate year generation discussed in the prefiled rebuttal testimony of Mr. David E. Mills. This adjustment now results in a decrease to net operating income of $103,079 compared to the $100,185 included in the supplemental filing.

VII. ADJUSTMENTS PROPOSED BY OTHER PARTIES

Q. Have the parties to this case proposed other adjustments to the Company's operating results?

A. Several parties have proposed adjustments to the Company's operating results, some of which I have discussed, or provided reference to the appropriate Company witness who discusses the proposed adjustment. Other items that have not been discussed previously are:

<u>Colstrip Costs</u>

Sierra Club's witness Mr. Hausman requests that the Commission issue an order in this proceeding requiring that the Company conduct a thorough, forward-going cost and risk study of the Colstrip plant based on "proposed" rules and regulations. Mr. Hausman's request should be denied as this topic is more appropriate in the Integrated Resource Plan ("IRP") process. The Commission has already recognized this in its letter accepting the Company's 2011 IRP. The Commission included the following provisions in that letter.

- ***Follow-Up No Colstrip Analysis***: PSE should model a scenario without Colstrip that includes results showing how PSE would choose to meet its load obligations without Colstrip in its portfolio and estimate the impact on NPV (cost) of its portfolio and rates.
- ***Continuing Colstrip Operations Analysis***: PSE should conduct a broad examination of the cost of continuing the operation of Colstrip over

the 20-year planning horizon, including a range of anticipated costs associated with federal EPA regulations on coal-fired generation.

Because this analysis will be done in PSE's IRP process, there is no need for the Commission to order further analysis as part of this proceeding.

<u>Consolidated Tax Adjustment</u>

Mr. Marcelia discusses this adjustment, proposed by ICNU witness Ms. Blumenthal, in his prefiled rebuttal testimony, Exhibit No. ___ (MRM-14T).

Q. Are there any other issues that relate to revenue requirement that you wish to comment about?

A. Yes. Mr. Schooley discusses the Power Cost Adjustment and makes some statements about the mechanism that are not accurate. Mr. Elgin and Mr. Schooley discuss attrition and how the Company did not carry its burden in proving that it suffers from attrition. I will reply to the PCA comments first and then the attrition testimony. Mr. Don Gaines and Dr. Olson discuss how Mr. Elgin misinterprets their testimony concerning attrition.

<u>Power Cost Adjustment ("PCA")</u>

Mr. Schooley's testimony contains several statements about the PCA that are not accurate.[7] The first inaccurate statement is that the PCA gives the Company a full return of and on certain regulatory assets. This is incorrect as the PCA treats these costs as variable, and any deviation in recovery is added to the under or over

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[7] <u>*See*</u> Exhibit No.___ (TES-1T), p. 5, lines 5-12.

recovery of power costs and will be treated in accordance with the PCA bands. The Company absorbs the first $20 million in the first band, 50% in the next $20 million, etc. The second statement that is inaccurate is listing taxes as an item of recovery. The PCA was specifically designed to exclude taxes other than the deferred taxes offsetting rate base items and the taxes built into the return on rate base items. There is no line item for taxes. The third inaccurate statement is that PSE recovers all PCA costs by updating the base line through frequent rate filings. As shown by the actual history of PSE's over and under recoveries in the first ten PCA periods, updating the base line rate does not mean PSE recovers all its costs. *See* Exhibit No. ___ (JHS-30). As explained earlier, variable costs are updated to actual variable costs in the PCA period and any over or under recovery is run through the PCA bands. Fixed costs determined in a GRC are held constant and the actual costs are ignored for the PCA calculation. The fourth inaccurate statement is that PSE is guaranteed the rate of return on $2 billion of rate base. These costs are treated like fixed costs, and again, any over or under recovery of these costs are run through the PCA dead and sharing bands. In addition, as these costs are fixed, any growth in revenues (due to load) associated with these costs, as with all fixed costs in the PCA, is used to offset cost increases or added to cost decreases in variable power costs and treated under the PCA bands. This is a customer benefit that Mr. Schooley ignores and is a major deviation from how other costs are recovered in rates.

Attrition

Mr. Elgin provides testimony on attrition in his prefiled direct testimony, Exhibit No. ____ (KLE-1T). Mr. Gaines and Dr. Olson explain in their prefiled rebuttal testimony how Mr. Elgin misunderstood their respective testimonies.

Q. How do you respond to Mr. Elgin's discussion of attrition adjustment in Washington?

A. Mr. Elgin's testimony does raise some important points about attrition adjustments in Washington State. As can be seen in the sample orders Mr. Elgin provides in Exhibit No. __(KLE-6), the Commission has tried various methods of addressing attrition. These include construction work in progress being added to ratebase, end of period ratebase instead of average of monthly average ratebase, a trending analysis and likely other mechanisms not discussed in these excerpts. Many times the Commission did not allow a previously approved mechanism in a subsequent regulatory filing. So when Mr. Elgin states "PSE should have presented an attrition study and specified the attrition adjustment, consistent with Commission precedent and policy" it is unclear as to what is needed in an attrition study for it to be consistent with Commission precedent and policy. A company knows it must be able to prove that future revenues, expenses and rate base have an unbalanced growth. The Commission has stated such:

> Attrition is a complex phenomenon which results from an unbalanced growth in revenues, expenses and/or rate base that causes a change in the rate of return from its authorized level.[8]

The Commission has also stated:

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[8] *WUTC v. Puget Sound Power & Light Co.*, Docket No. U-85-53, Second Supplemental Order, 74 P.U.R.4th 536, 579 (May 1986).

> In determining an appropriate attrition allowance, the first step is to calculate results of operations after rate relief from the balance of the proceeding. Then, the revenues and costs are projected to the end of the attrition year…by use of appropriate growth factors as specified above. Then the company's results of operations are calculated based on experience of the projected costs, and the attrition rate of return is subtracted from the authorized rate of return, as adjusted for weatherization allowances, producing a rate of return differential. The rate of return differential is multiplied by the attrition year rate base to produce the attrition net operating income required for the company to achieve its authorized rate of return. The net operating income requirement is converted to gross revenue by use of a conversion factor and then is discounted to the test year to account for the time value of money. This result . . . constitutes the attrition allowance which is authorized in this proceeding….[9]

This explains the trending methodology and sounds simple. However, there are many estimates, assumptions and forecasts required in determining growth factors all of which can be argued and debated. There are just as many arguments as to what are the proper costs to adjust.

Mr. Elgin states his preference that a "… properly performed attrition study using trend analysis is necessary…"[10]. He does not explain how this kind of study would meet the stricter interpretation of pro forma adjustments and of known and measurable changes that the Commission has recently adopted, and that other Commission Staff champion in their property tax adjustment or new resource adjustments. Nor does he explain how this trend analysis fits with the arguments Commission Staff used in *WUTC v. Washington Natural Gas Company*, Docket No. UG-920840, a case Mr. Elgin cites. In that proceeding, WUTC Staff opposed the attrition adjustment because:

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[9] *WUTC v. Pacific Power & Light Company*, Docket Nos. U-82-12 & U-82-35, Fourth Supplemental Order, 51 P.U.R.4th 158, 183 (Feb. 1983).

[10] *See* Exhibit No. ___ (KLE-1T), page 77, lines 4 and 5.

> Attrition analysis was adopted by the Commission in the early 1980's to cope with the measurement problems encountered by historical ratemaking during inflationary periods. It was accepted by this Commission during those economic cycles because it was recognized that historical test periods with restated pro forma cost of service results may not be representative of revenue, expense and rate base relationships during the rate year. Since we are no longer in an inflationary period, historical restated pro forma results of operation should provide the utility with an opportunity to earn a fair return, making an attrition analysis unnecessary.[11]

The Commission denied the attrition adjustment in the Forth Supplemental Order in that Docket, stating:

> Past attrition adjustments have been allowed when the Commission found that, without such an adjustment, the company would have no reasonable opportunity to earn its authorized rate of return. The Commission does not believe that the company will be impeded from earning its authorized return in today's climate of low inflation, declining interest rates, and increasing gas sales.

This Commission directive would likewise indicate that in today's environment—with low inflation and declining interest rates—PSE is not impeded from earning its authorized return, and yet the evidence in this and past cases demonstrates the opposite. PSE has not earned its authorized return for several years.

Q. Do you agree that low inflation should preclude use of an attrition adjustment?

A. No. As recognized by James C. Bonbright in *Principles of Public Utility Rates,* inflation is not the sole factor in determining attrition:

> The percentage return is equal to revenue minus costs all divided by the plant investment. Whenever the relative growth in plant investment or expenses outpaces the growth in revenues, attrition occurs. Many factors such as environmental requirements,

[11] *See* Docket No.UG-920840, Exhibit No. T-155 (KLE-T), page 22.

> technological changes, scales and scope economies and diseconomies, growth in demand, own price elasticity of demand, as well as inflation, can affect these return elements. But most people agree that if attrition is the fulcrum, then inflation is the pivot on which the fulcrum rests.[12]

Q. Can you provide an example of how the Company can experience attrition in low inflationary times?

A. Yes, the following is a good example as presented in Accounting for Public Utilities:

> Adding plant with a higher unit cost than the average unit cost embedded in rates also causes attrition. For example:
>
> | | Unit Cost | System Average Cost |
> |---|---|---|
> | Unit 1 | $100 | $100 |
> | Unit 2 | $200 | $150 |
> | Unit 3 | $300 | $200[13] |
>
> If rates were set to cover a system average cost of $150, then the utility would suffer earnings attrition after the acquisition of the third unit due to the rising costs of new facilities. Once rising acquisition costs are included in rates, attrition will continue even if inflation does not. For example, assume the utility above has the system average cost of $200 incorporated into rates and purchases a fourth unit at the same cost as the third:
>
> | | Unit Cost | System Average Cost |
> |---|---|---|
> | Unit 1 | $100 | $100 |

[12] James C. Bonbright, *et al.*, *Principles of Public Utility Rates (2d ed.)* at 349-50 (1988).

[13] Robert L. Hahne *et al., Accounting for Public Utilities*, Section 8.05, at 8-6, Rel 10/2009.

Unit 2	$200	$150
Unit 3	$300	$200
Unit 4	$300	$225

> If rates are designed after the completion of Unit 3 to cover average costs of $200, they will not sustain Unit 4 at a cost of $300. From this simple illustration, it is apparent that addition of facilities, even in the absence of current inflation, will cause attrition until older units are retired.[14]

Ms. Sue McLain has testified regarding the dramatic increases in costs of materials such as gas main and poles. As demonstrated above, when these rising acquisition costs are locked into rates, attrition continues even if inflation does not. That is precisely the situation PSE is facing.

Q. Do you have any further response to Commission Staff's testimony on attrition studies?

A. Yes. Mr. Elgin also states "An attrition study is a simple effective tool for addressing load changes caused by all factors, and it provides the Commission with the best tool for determining fair rates."[15] I do not know how many attrition adjustments Mr. Elgin has done but, having been involved with a few, I find that statement to be very far from the truth. They are not simple adjustments. Again, the problem is that there are no real guidelines as to what will be considered appropriate proof for an attrition study. This is shown in the excerpts of the orders that Mr. Elgin provides. Obviously some attrition adjustments were allowed but, just as obviously, many adjustments were not. With the Commission

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[14] *Id.*

[15] *See* Exhibit No. ___ (KLE-1T), page 80, lines 1 through 3.

indicating that it believes these adjustments are not appropriate in periods of low inflation and interest rates it is even a higher hurdle to clear.

Both Mr. Schooley and Mr. Elgin state that the Company needs to prove that it has an attrition problem. Actually a historical proof is in Mr. Schooley's testimony. On page 8 of his testimony he lists each year in which PSE filed a general rate case. Just using natural gas as an example, because it does not have the complicating factor of new resources, each of the cases are fully pro formed and restated and revenues adjusted to include any new rate changes during the test year. In each of these cases the Commission authorized a rate increase for natural gas, even when it approved a lower rate of return than the prior general rate case. These rate increases understate the attrition because of the lower rate of return the Commission authorized. In what was the rate period for the previous period, PSE should have had the opportunity to earn its previously authorized rate of return. Even proforming in the revenues from that previous general rate case, the new test year was deficient.

Mr. Schooley goes on to state that Staff expects all three companies (Avista, PacifiCorp and PSE) will continue this pattern of regularly seeking rate relief via general rate cases. This is an instance where Mr. Schooley and I agree. The very fact that PSE continuously fails to earn its authorized return, even with these frequent rate case filings, documents the attrition problem.

Mr. Schooley and Mr. Elgin do offer a unique proposal to address this attrition problem. They suggest using the Commission Basis report as a means to expedite interim rate relief between general rate cases. Mr. Schooley immediately qualifies what would be allowed in such an expedited filing.[16] The Company does not necessarily agree with that part of the proposal, however, what is unique is that this type of proposal eliminates what is a major problem—the lack of understandable criteria to prove attrition. Even if it were not the Commission Basis report that is ultimately used for such an expedited filing, the clear definition of an acceptable methodology for proving attrition is a benefit for all parties. The Company would be willing to meet with Commission Staff and other interested parties to see if consensus could be reached on how to present an acceptable method for showing the impacts of attrition.

VIII. REVENUE DEFICIENCY

Q. Would you please explain Exhibit No. ___ (JHS-22)?

A. Exhibit No. ___ (JHS-22) presents the calculation of the revenue deficiency based on the pro forma and restating adjustments proposed by the Company and discussed above. As shown on page 1 of Exhibit No. ___ (JHS-22), based on $4,893,796,925 invested in rate base and 326,017,733 of net operating income, the Company would have an electric retail revenue deficiency of $125,401,321.

<u>Cost of Capital</u>

This schedule, shown on page 2 of Exhibit No. ___ (JHS-22), reflects the Company's proposed capital structure for this proceeding and the associated costs

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[16] Exhibit No. ___ (TES-1T), pp. 7-8.

for each capital category. The capital structure and costs are presented in the Prefiled Rebuttal Testimony of Donald E. Gaines, Exhibit No. ___ (DEG-14CT). The costs for debt and cost of equity have been adjusted for the change in interest cost and equity capital as discussed by Mr. Gaines and the rate of return is 8.26%.

Conversion Factor

The conversion factor, shown on page 3 of Exhibit No. ___ (JHS-22), is uncontested in this proceeding and remains at 62.0749%.

IX. COMPARISON OF COMPANY AND COMMISSION STAFF REVENUE DEFICIENCY

Q. Has the Company provided an Exhibit that shows the difference between the Company and Commission Staff adjustments?

A. Yes. As mentioned earlier the Company has prepared such an exhibit and it is presented in Exhibit No. ___ (JHS-23). Each adjustment is shown with the relative net operating income and rate base impact shown for each party. The difference between these two presentations is shown in the third section of the exhibit. Where there are no differences in net operating income or rate base amounts, the adjustment is uncontested. If there is a revenue requirement impact shown in this third section for these adjustments, it would be due to the different rate of return proposed by the parties.

X. UNIT COST ANALYSIS

Q. Has PSE updated its unit cost analysis?

A. Yes. Please see Exhibit No. ___ (JHS-24) for the unit cost analysis. A unit costs analysis consists of a comparison of the major categories of the income statement and rate base that have been pro formed and restated for each of the test periods for this general rate proceeding and the last general rate proceeding. These major categories are divided by the delivered load for the appropriate test period to determine their unit cost for that particular period. The difference between the current period and prior period unit costs are multiplied by the delivered load for the current regulatory period. This product determines how much that major category has increased or decreased in cost since the last regulatory period taking into consideration load growth and its associated revenue growth. This exhibit is presented for informational purposes as to the major categories causing the revenue deficiency.

XI. PCA EXHIBITS

Q. Please describe Exhibit No. ___ (JHS-25).

A. Exhibit No. ___ (JHS-25) presents the adjusted exhibits for the Power Cost Adjustment Mechanism. Page 1 of this exhibit presents Exhibit A-1, Power Cost Rate reflecting a PCA baseline rate of $63.769 per MWh based on the Company's rebuttal power cost and production related adjustments. Other than the requested treatment for Jackson Prairie storage rent and contract major maintenance discussed earlier in my testimony, the methodology applied to determine this rate is consistent with that set forth in the PCA Settlement Agreement, under Docket No. UE-011570, and the PCA Compliance Settlement Agreement, under Docket No. UE-031389.

Q. Does the Commission have the detailed information necessary to calculate the power cost rate based on its final determination of the appropriate production rate base and operating expenses to be included in rates?

A. The calculations used to determine the line items on Schedule A-1 are included in workpapers. To ensure that these pages are accurate, it would be best for the Commission to have the Company recalculate these exhibits based on the final Commission order as to allowed power costs and production resources. The Company would then file the revised pages with the compliance filing that is required to implement the Commission's final order.

XII. CONCLUSION

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.