EXHIBIT NO. ___(KJB-11T)
DOCKET NO. UE-121373
DOCKET NO. UE-121697/UG-121705
DOCKET NO. UE-130137/130138
WITNESS: KATHERINE J. BARNARD

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of PUGET SOUND ENERGY, INC. For Approval of a Power Purchase Agreement for Acquisition of Coal Transition Power, as Defined in RCW 80.80.010, and the Recovery of Related Acquisition Costs	DOCKET NO. 121373
In the Matter of the Petition of PUGET SOUND ENERGY, INC. and NW ENERGY COALITION For an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and to Record Accounting Entries Associated with the Mechanisms	DOCKET NOS. UE-121697 and UG-121705 (Consolidated)
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC., Respondent.	DOCKET NOS. UE-130137 and UG-130138 (Consolidated)

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

In Support of the Multiparty Settlement
Re: Coal Transition PPA and other Pending Dockets

MAY 8, 2013

PUGET SOUND ENERGY, INC.

PREFILED REBUTTAL TESTIMONY
(NONCONFIDENTIAL) OF KATHERINE J. BARNARD

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PUGET SOUND ENERGY, INC.

PREFILED REBUTTAL TESTIMONY (NONCONFIDENTIAL) OF KATHERINE J. BARNARD

I. INTRODUCTION

Q. Are you the same Katherine J. Barnard who provided prefiled testimony and supporting exhibits on behalf of Puget Sound Energy, Inc. ("PSE") in these proceedings?

A. Yes, in Docket No. UE-121373 I filed prefiled direct testimony, Exhibit No. ___(KJB-1T), and one supporting exhibit, Exhibit No. ___(KJB-2), on September 20, 2012. I filed prefiled rebuttal testimony, Exhibit No. ___(KJB-3T), on November 16, 2012.

In Docket Nos. UE-130137 and UG-130138 (consolidated), I filed prefiled direct testimony, Exhibit No. ___(KJB-1T), and supporting exhibits, Exhibit No. ___(KJB-2) through Exhibit No. ___(KJB-10), on February 1, 2013.

In Docket Nos. UE-121697 and UG-121705 (consolidated), I filed prefiled direct testimony, Exhibit No. ___(KJB-1T), and supporting exhibits, Exhibit No. ___(KJB-2) through Exhibit No. ___(KJB-5) on March 1, 2013.

Q. What is the purpose of this rebuttal testimony?

A. This prefiled rebuttal testimony addresses the testimony submitted on behalf of the Industrial Customers of Northwest Utilities ("ICNU"), Public Counsel, the Northwest Industrial Gas Users ("NWIGU"), Nucor Steel ("Nucor") and Kroger in the above dockets. Specifically, I will address the various witnesses' testimony regarding their concerns with the K-factor and rate plan associated with the decoupling dockets and the concerns raised regarding the Expedited Rate Filing ("ERF").

II. THE EXPEDITED RATE FILING IS CONSISTENT WITH THE MATCHING PRINCIPLE

Q. How do you respond to parties concerns that the ERF has somehow violated the matching principle?

A. I disagree with these assertions, and I respond to them in more detail below. In summary, PSE appropriately used the 12-month period ending June 30, 2012 as the test period for the ERF filing. PSE used revenues, expenses and rate base associated with the test period in its filing.

Q. How do you respond to Mr. Dittmer's claim that the matching principle was fundamentally violated by not annualizing revenue and expense?

A. I disagree with his claim and his narrow characterization of the matching principle. The matching principle requires that the "matching of revenues and expenses must be reasonable and not necessarily absolute."[1] The ERF filing that is part of the Multiparty Settlement matched revenues and expenses within the test period. However, as discussed in my direct testimony, PSE utilized end of period rate base as a means to address some of the regulatory lag inherent in historical ratemaking. The use of end of period rate base to address regulatory lag, while

[1] *WUTC v. Wash. Natural Gas Co.*, Cause No. U-80-111, Third Supplemental Order, p. 7 (Sept. 24, 1981).

matching revenues and expenses in the test year, is reasonable and does not violate the matching principle

Q. Do you agree with Mr. Dittmer's revenue adjustment associated with annualizing customer counts?

A. No. As discussed above, Mr. Dittmer's adjustment is not necessary under the matching principle. Moreover, Mr. Dittmer's adjustment is incomplete and one-sided because 1) it does not consider the additional bad debt, state utility tax, or the regulatory fees associated with the revenues that he proposes to include; and 2) it does not annualize the depreciation expense that is also associated with the use of end of period rate base. If the test period is adjusted to annualize revenues based on year-end customer counts, then at a minimum the adjustment should include the corresponding annualization of depreciation expenses associated with the end of period plant values. Exhibit No.___(KJB-12) is a copy of PSE's response to Public Counsel Data Request No. 60, which shows the ERF related depreciation expense on a monthly basis. Annualization of the June 2012 depreciation expense increases ERF related depreciation expense levels by $3,783,910 for electric and $1,310,663 for gas.

Q. Have you calculated the revenue deficiency if Mr. Dittmer's adjustment is corrected in the manner described above?

A. Yes. Exhibit No. ___(KJB-13) updates Mr. Dittmer's Exhibit No. ____(JRD-4) to complete the revenue adjustment for electric operations. As shown on Line 34 of page 1 and in detail on page 2, had Mr. Dittmer included the end of period depreciation expense and reflected the additional taxes that would be associated with the incremental revenues, the adjustment would have reduced net operating income and therefore increased the revenue deficiency for electric operations. This corrected adjustment confirms that the ERF, as filed, is reasonable.

Q. Do you have additional concerns with Pubic Counsel's adjustment for natural gas revenues?

A. Yes. In addition to excluding the annualization of depreciation expense and the additional taxes associated with the revenue adjustment, Public Counsel's adjustment for natural gas revenues included only the year-end customer counts for residential and small commercial/industrial customer classes; other classes were omitted.

According to workpapers provided in support of Exhibit No. ___(JRD-5), Mr. Dittmer noted that "customer count numbers for other classes seemed suspect, suggesting customer migration that was causing the adjustment results to be suspect." He therefore excluded those classes. Because only the residential and small commercial classes, which had positive adjustments, were included in Public Counsel's adjustment, the adjustment is overstated.

Q. Was there customer migrations that affected Mr. Dittmer's adjustment calculations?

A. Yes. It is common for gas customers to switch schedules, but comprehensive data on this movement is not separately tracked. However, there is one instance of customer migration that should be included in these calculations. As a result of the implementation of a minimum volume requirement on Schedule 41 in the

2011 general rate case, Docket UG-111049, 404 customers moved from Schedule 41 to Schedule 31 in May 2012. By including an upward adjustment to Schedule 31 revenue in his adjustment, Mr. Dittmer unknowingly included the revenue on these customers' destination schedule, and by excluding Schedule 41 from his adjustment, he unknowingly omitted the other side of the transaction, the revenue reduction on Schedule 41. If commercial/industrial Schedule 31 is included in the adjustment, Schedule 41 must also be included.

Q. Have you modified Mr. Dittmer's adjustment to reflect this customer migration?

A. Yes. I refined his adjustment to account for the actual test year consumption of the 404 customers. This refinement results in a decrease to the revenue adjustment.

Q. Are there other reasons Public Counsel's adjustment calculations might have yielded "suspect" results?

A. Yes. There is a computational error in Public Counsel's calculation of the adjustment for Schedules 85/85T. When this error is corrected, the adjustment for these schedules goes from $1,448,228 to $91,881, a change of -$1,356,357.

Q. Are there other schedules that should be included in the adjustment?

A. Yes. Mr. Dittmer calculated adjustments for Schedules 86/86T and 87/87T but did not include them in his adjustment. PSE is not aware of any major migration issues with these schedules that would preclude their inclusion, based on the approach taken by Mr. Dittmer. Also, he did not calculate an adjustment for

Schedules 71, 72 and 74, which are rentals. Again, excluding these schedules makes his adjustment one sided.

Q. How do all the changes you suggest impact Public Counsel's proposed revenue adjustment?

A. These items change Public Counsel's revenue adjustment by -$320,585. The total revised adjustment is $1,459,248. The changes are summarized in Table 1.

Table 1: Changes to Public Counsel Revenue Adjustment

Description	Change	Revenue Adjustment
Public Counsel residential/commercial adjustment		$1,779,833
Correct 85/85T error and add sales/transport schedules (86/86T & 87/87T)	$(1,773,741)	
Adjust for Schedules 31/41 migration	$1,581,489	
Add Schedules 71/72/74	$(128,333)	
Revenue Adjustment		$1,459,248

Q. Have you recalculated the natural gas deficiency after addressing the necessary modifications discussed above?

A. Yes. Exhibit No. ___(KJB-14) presents updates to Mr. Dittmer's Exhibit No. ___(JRD-5) to complete the revenue adjustment for natural gas operations. The exhibit incorporates the necessary changes to reflect end of period depreciation expense and additional taxes associated with the revenue adjustment, as well as the corrections to the estimated revenues outlined above. Line 32 of page 1 and the detail presentation on page 2, shows that the impact of the corrected adjustment would have a modest impact on net operating income and confirms that the Company’s ERF, as filed, is reasonable.

Q. How do you respond to claims by Mr. Deen on behalf of ICNU that the Company improperly used a “hybrid” test year? Exhibit No. ____(MJD-1T) page 3, line 8.

A. Mr. Deen makes several erroneous assumptions and fails to recognize the Commission's practice and guidance in this regard. The Multiparty Settlement uses the Commission Basis Report – a regulatory report – as the foundation for the development of the ERF rates; it pro forms in the most current rates prior to calculating the surplus or deficiency and thereby creates the proper alignment between revenues, expenses and rate base for the categories being collected in ERF Schedule 141.

Mr. Deen incorrectly suggests that the Company’s use of a test year ending June 30, 2012 is not permitted under the Commission’s rules and implies that a test year may only be presented on a calendar year basis. However, the Commission does not have specific rules regarding the timing of a test year and, in fact, it is quite common for a test period to <u>not</u> to be set on a calendar year basis. Additionally, although the Commission’s rules currently require that the Commission Basis Report be filed annually within four months of the end of the calendar year, the Commission’s rules also require that utilities file quarterly reports on actual results of operations and that such reports provide both the monthly results of operations as well as the latest 12 months' ending balances.[2] The results of operations report for the 12 months ending June 30, 2012 was the basis for the actual results of operations presented on page 2 of Exhibit Nos. ___(KJB-3) and ___(KJB-4) column (A) in the ERF and there is no basis to assume that an additional Commission Basis Report cannot be prepared on a mid-year basis. In fact, prior to June, 2001, the Commission required a filing of a Commission Basis Report on a semi-annual basis.

Finally, I disagree with the implication in Mr. Deen's testimony that PSE's ERF related expenses and rate base must be recovered on the same basis and in the same relationship as its non-ERF related revenue, expenses and rate base. He incorrectly states that PSE's cost of capital and power costs would be set based on the 2010 test year from PSE's last general rate case, but that its ERF related expenses and rate base would be set using a more current test period and that this somehow violates the matching principle. Contrary to Mr. Deen's assertions, PSE's current power costs and cost of capital were set in PSE's 2011 general rate case based on a rate year of May 2012 through April 2013, not on the test year 2010.

Moreover, the Commission allows for cost of service to be determined using differing test periods for differing underlying cost and rate base categories. Each time PSE increases or decreases its rates under a Power Cost Only Rate Case in Schedule 95, PSE's power cost rates are recovered based on the relationship of

[2] WAC 480-100-275 and 480-90-275

revenue, expenses and rate base of a more current test period, while its non-power cost rates are recovered under the relationship from an older test period. Thus, the matching principle is not violated merely from the bifurcation of the recovery of separate categories of prudently incurred costs.

Additionally, in the Final Order in PSE's 2011 general rate case the Commission commented favorably on a proposal by Commission Staff that allowed updating rate base and net operating income beyond those approved in the current general rate case while holding steady the rate of return established in that general rate case.

Q. How do you respond to Mr. Dittmer's concerns that PSE did not include all the restating adjustments in the ERF? Exhibit No. ___(JRD-1T) page 13, lines 18-22.

A. As previously noted in my prefiled direct testimony, the omitted restating adjustments do not have a material impact on the results of the ERF. In response to data requests, PSE provided information showing both the historical level of the omitted adjustments along with the calculations demonstrating that the omitted adjustments do not have a material impact on the filing. Mr. Dittmer also concluded that the "omission probably does not have a material revenue impact.[3]"

The following tables list the omitted adjustments and their impact on electric and natural gas net operating income.

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[3] *See* Exhibit No. ___(JRD-1T), page 17, lines 5- 7.

ELECTRIC

Adjustment	Impact on NOI 2011 GRC	Impact on NOI June 2012 CBR	Impact in June 2012 CBR on: ROR	Impact in June 2012 CBR on: ROE
Normalize Injuries and Damages	$ (725,618)	$ (353,811)	-0.01%	-0.01%
Excise Tax and Filing Fee	$ (200,979)	$ (35)	0.00%	0.00%
D&O Insurance	$ 33,584	$ 8,722	0.00%	0.00%
Interest on Customer Deposits	$ (47,149)	$ (40,879)	0.00%	0.00%
Rate Case Expenses	$ 44,411	$ 226,099	0.00%	0.01%
Gains & Losses on Property Sales	$ (1,028,316)	$ (782,279)	-0.02%	-0.03%
Total	$ (1,924,067)	$ (942,182)		

NATURAL GAS

Adjustment	Impact on NOI 2011 GRC	Impact on NOI June 2012 CBR	Impact in June 2012 CBR on: ROR	Impact in June 2012 CBR on: ROE
Normalize Injuries and Damages	$ (54,310)	$ 260,104	0.02%	0.03%
Excise Tax and Filing Fee	$ (49,256)	$ (6,086)	0.00%	0.00%
D&O Insurance	$ 23,376	$ 6,091	0.00%	0.00%
Interest on Customer Deposits	$ (21,705)	$ (18,121)	0.00%	0.00%
Rate Case Expenses	$ (142,724)	$ (28,709)	0.00%	0.00%
Gains & Losses on Property Sales	$ (92,595)	$ (59,816)	0.00%	-0.01%
Total	$ (337,213)	$ 153,463		

III. END OF PERIOD RATE BASE IS APPROPRIATE

Q. Do you agree that the use of end of period rate base is "novel" or represents a "new theory" as claimed by ICNU witness Mr. Deen and Public Counsel witness Mr. Dittmer?[4]

A. No. Although the more common approach for calculating rate base utilizes the average of monthly averages (AMA), the use of end of period rate base is certainly not new nor is it prohibited. Evidence indicates that the Commission approved the use of end of period rate base as far back as the 1970s and approved its use again as recently as 2002. In fact in the Final Order in PSE's 2011 general rate case, the Commission listed end of period rate base as one of the mechanisms "the Commission already employs" to address regulatory lag.[5]

Q. Please describe the circumstances under which the Commission has approved the use of end of period rate base.

A. In 2002, the Commission approved the use of end of period rate base in Docket TO-011472, the Olympic Pipeline rate case. The Commission relied upon Commission Staff witness Maurice Twitchell's testimony that cited the Commission's Third Supplemental Order in Cause No. U-80-111. In the U-80-111 Order the Commission stated that the "utilization of average rate base was not cast in stone" and the commission reached the following conclusions:

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[4] *See* Exh. No. ___(JRD-1T), p. 14, line 1; Exh. No. ___(MCD-1T), p.7, line 8.

[5] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08 ¶ 491 (May 7, 2012).

1) Average rate base is the most favored

2) Year-end rate base is an appropriate regulatory tool *__under one or more__* of the following conditions:

(a) Abnormal growth in plant

(b) Inflation and/or attrition

(c) As a means to mitigate regulatory lag

(d) Failure of utility to earn its authorized rate of return over an historical period.

The evidence previously provided in this docket from Commission Staff witness Thomas Schooley, along with my prefiled direct testimony, Exhibit No. (KJB-1T) demonstrate that PSE has failed to earn its authorized rate of return over a historical period (2008 through 2011). Additionally, as was clear from the Commission's Final Order in PSE's 2011 general rate case, the Commission allows the use of end of period rate base as a method to address regulatory lag.

IV. PSE'S EARNINGS SHORTFALL IS A SERIOUS CONCERN THAT IS APPROPRIATELY ADDRESSED IN THE MULTIPARTY SETTLEMENT

Q. Do you agree with Mr. Deen's testimony that if PSE waited to use the calendar year 2012 test year the claimed revenue deficiency would disappear? Exhibit No. ___(MJD-1T) page 4, lines 17-19.

A. No. Mr. Deen has assumed that the company's results of operations in the second half of 2012 have "drastically improved," yet he provides no evidence to substantiate this claim. Since filing the ERF, consistent with WAC 480-100-257 and WAC 480-90-257, the Company has filed its annual Commission Basis Report for the calendar 2012 period. Contrary to Mr. Deen's testimony, the report demonstrates that the Company continues to earn below its authorized return on equity. During 2012, PSE's Commission Basis Results indicated that the Company earned an 8.11% return on equity for electric operations and 8.78% return on equity for gas operations, both significantly less than the company's authorized return on equity of 9.8%.

Q. Do you agree with ICNU witness Mr. Deen's testimony that "if PSE considered the U.S. Treasury Grant received for its Wild Horse Wind Farm, all shortfalls would essentially disappear"?[6]

A. No. In fact, I am unclear about what is meant by this section of Mr. Deen's testimony. As the Treasury Grant for the Wild Horse Expansion Project has been in rates for many years, I can only presume that he must actually be referring to the Treasury Grant from PSE's Lower Snake River Wind Facility that was just incorporated in to PSE's Schedule 95a rates effective February 1, 2013 under WUTC Docket No. UE-122001. The bottom line is that customers are already receiving the full benefits of the Treasury Grant as ordered by the Commission. The Treasury Grants will not make all shortfalls disappear, as Mr. Deen claims.

Q. How do you respond to Mr. Deen's concern that the settlement gives no consideration to the "over-recovery" of power costs? Deen, Exhibit No. ___(MCD-1T), page 11, lines 5 through 11.

A. Mr. Deen relies on the budget versus actual figures provided in PSE's response to ICNU Data Request No. 2.4 in the ERF docket to reach his conclusion that PSE benefited from "over-recoveries" of $41 million and $44 million for the 2011 and

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[6] Exhibit No. ___(MCD-1T) at p. 4 lines 19-21.

2012 periods respectively. PSE's power costs are recovered through the PCA mechanism. The PCA mechanism is a holistic, balanced and comprehensive mechanism that provides for a sharing of the costs and benefits related to the inherent variability in power costs. While power costs are variable in the PCA mechanism, there are many offsetting and compensating factors built in to the mechanism that offset and balance the recoveries of these variable power costs. For instance, all of PSE's fixed costs, such as its production rate base and depreciation expense and its production O&M expenses, are held at a historic test year basis through the mechanism. By only focusing on the variable portion of PSE's production costs, and not focusing on the other mitigating PCA related costs, Mr. Deen presents a one-sided picture. The PCA mechanism is the existing and appropriate mechanism that provides for the sharing of these costs and benefits. The PCA mechanism has been examined by the Commission in several prior rate cases, and its holistic nature has not been modified from its original structure and intent. Furthermore, Mr. Deen's reliance on budget versus actuals is misplaced. Budgeted power costs are based on the Company's internal estimates of power cost expenses that will be incurred during the year and do not reflect variances associated with the level of power costs that are recovered through rates. This is apparent by looking on page 5 of Exhibit No. ___(MCD-7) at the line "customer portion of the deferral" which references the PCA mechanism and costs that would be deferred as a result of that mechanism. The 2012 budgeted customer deferrals were originally anticipated to be over $6 million, however the actual deferral was only $2 million, this in part was a result of the reduction in baseline power costs from the 2011 GRC, which became effective in May 2012, and reduced the baseline power costs by more than $49M. This reduction was not in effect during the entire 2012 period that Mr. Deen discusses in his testimony. Additionally, PSE has filed for a further reduction in the power cost rate under Docket No. UE-130617 to align power costs with the rate year beginning in November 2013. Accordingly, a more appropriate comparison to use for PSE's power cost over-recoveries would be to refer to PSE's annual report filed in its PCA compliance filing under UE-130471. This report allows the full picture of PSE's PCA costs to be seen. The annual PCA compliance filing shows that PSE has over-recovered PCA costs by $34.8 million in 2011 and $25.6 million in 2012 as opposed to the one-sided amounts referenced by Mr. Deen. This is demonstrated by the fact that, while 2011 and 2012 represent years in which PSE over-recovered, the PCA annual report also shows that over the life of the PCA, PSE has actually under-recovered PCA costs by $2.3 million. By isolating only the variable power cost portion of PSE's PCA related costs and by ignoring the offsetting and mitigating factors of the PCA mechanism, and only focusing on select years, Mr. Deen has skewed the events surrounding PSE's power cost recoveries.

As discussed in my prefiled testimony in the ERF docket, power costs have been appropriately removed from the ERF filing because 1) there is another mechanism in place (the PCA mechanism) that addresses changes in those costs and 2) in a general rate proceeding power costs are set on a forward-looking, pro forma basis and that methodology is inconsistent with the historical restating approach embedded in the CBR. As there is a mechanism currently in place that addresses the costs and benefits associated with power costs, Mr. Deen's arguments regarding PSE's over-recovery of power costs should not affect the proposed ERF and decoupling mechanisms, agreed to in the Multiparty Settlement, which relate to recovery of PSE's non-production costs.

Q. Is Mr. Deen correct that the 2011 GRC rate increase would have been "negligible" if not for the addition of Lower Snake River wind facility? Exhibit No. ___(MJD-1T) page 41, lines 1 and 2.

A. No. PSE's non-production related revenue deficiency was more than $112.7 million. In contrast, despite the additional investment associated with the Lower Snake River ("LSR") wind facility, the results of the 2011 GRC reduced the overall baseline power cost rate and resulted in an overall reduction in power cost associated revenue requirements of more than $49 million. As demonstrated in Attachment A to PSE's Response to Public Counsel Data Request No. 53 in the ERF dockets, the baseline power cost rate decreased from $67.365 per MWH down to $65.027/MWH. An excerpt of the response is as follows:

Test Year	2004 GRC Sep-03	2006 GRC Sep-05	2007 GRC Sep-07	2009 GRC Dec-08	2011 GRC Dec-10
1 Total Revenue Requrement Deficiency (Surplus)	57,688,822	(22,849,574)	130,282,079	74,060,716	63,319,369
2 PCA Baseline Rate	51.445	59.582	65.740	67.365	65.027
3 Proceeding prior baseline rate was from	2003 PCORC	2005 PCORC Update	2007 PCORC	2007 GRC	2009 GRC
4 Prior baseline rate previously in effect	48.460	59.580	62.640	65.740	67.365
5 Test Year Delivered Load	19,334,019	20,339,227	21,283,656	21,821,674	21,143,300
6 Calculated Annual Production Deficiency (Surplus), line 2 minus line 4 multiplied by line 5	57,714,924	31,521	65,983,046	35,469,758	(49,432,948)
7 Non-Production Deficiency, line 1 minus line 6	(26,102)	(22,881,095)	64,299,033	38,590,958	112,752,317

This overall reduction in power costs was primarily driven by the reductions in fuel and market power purchases of $159 million that more than offset the $122 million of revenue requirements associated with the LSR project.

V. ICNU PROPOSED ADJUSTMENTS SHOULD BE REJECTED

Q. How do you respond to Mr. Gorman concern that the equity calculation used in the 2011 Commission Basis Report included in Exhibit No. ___(KJB-7) is incorrect?

A. Mr. Gorman is confusing regulated common equity value with common equity as calculated on a GAAP basis. Mr. Gorman states the equity calculation used on page 3 of Exhibit No. ___(KJB-7) is incorrect and references what he perceives to be a "mismatch" with the common equity reflected on the balance sheet that was provided on page 8 of that exhibit. However, the balance sheet shown on page 8 is presented on a GAAP basis and the equity value reflected on page 3, is presented on a commission basis. The regulated equity value presented on page 3 of my exhibit is consistent with the methodology approved in the 2011 GRC, where the impacts of FAS 133 unrealized gains/losses and Other Comprehensive Income (OCI) are excluded for regulatory purposes, which is explained in the Prefiled Rebuttal testimony of Daniel A. Doyle Exhibit No. ___(DAD-1T)

Q. Does Mr. Gorman propose additional adjustments to the ERF?

A. Yes. Although he does not dispute that PSE's restating adjustments were calculated consistent with the Commission approved methodology, he has proposed changes to both the Pension Plan Adjustment and the Incentive Pay Adjustment.

For the Pension Plan Adjustment, he proposes abandoning the use of the four-year average pension contributions and instead he uses actual contributions made during the 12 months ending June 30, 2012. As discussed in Mr. Doyle’s testimony, pension plan contributions will vary based on actuarial estimates of the required plan funding requirements. As interest rates decline, the returns on the pension fund decline, thus requiring higher cash contributions to be made. The four-year average is used to smooth these variations in contributions and should be retained, and Mr. Gorman’s proposed adjustment should be rejected. PSE has calculated its pension plan expense included in the ERF filing as approved in its most recent general rate case, which is consistent with the CBR requirements under WAC 480-100-257 and 480-90-257.

Mr. Gorman also challenges the Company's adjustment for incentive pay. Mr. Gorman does not challenge that PSE's adjustment was calculated consistent with the Commission's approved methodology, but instead he questions whether incentive pay is appropriate. As discussed in my prefiled direct testimony, the approach utilized in the ERF filing for incentive pay adjustment is consistent with the methodology approved in Dockets UE-111048 and UG-111049 and therefore Mr. Gorman's adjustment should be rejected. PSE has calculated its incentive pay expense included in the ERF filing as approved in its recent general rate cases including its most recent, which is consistent with the CBR requirements under WAC 480-100-257 and 480-90-257.

VI. THE JEFFERSON TRANSACTION DOES NOT IMPACT ERF

Q. Please summarize the concerns of ICNU witness Mr. Deen and Public Counsel witness Mr. Dittmer regarding the impact on the settlement of the transfer of assets to Jefferson County Public Utility District No. 1 ("JPUD transaction").

A. Mr. Deen classifies the JPUD transaction as a known and measurable event and states that in the settlement, PSE has not accounted for the changes to its rate base and costs associated with the transfer. Mr. Dittmer states that the JPUD transaction needs to be addressed in any rate plan adopted and that there is little information in the settlement or testimony on the issue. He indicates it is not clear what the impacts will be to revenues as a result of the transfer. He further urges that the disposition of the gain on the JPUD transaction should not be impaired by the rate plan.

Q. How do you respond to these concerns?

A. I agree with Mr. Deen that the JPUD transaction is a known event; however, final payment for the assets that were sold to Jefferson County will not occur until 90 days after closing. This is a true-up that will account for improvements made to the Jefferson County electrical system during the first quarter of 2013. PSE intends to make an additional filing with the Commission to determine the proper accounting treatment for, and the allocation of the gain from, the JPUD transaction. Because the final reconciliation will impact the calculation of the gain, PSE does not expect to make the filing for the allocation of the proceeds until after the final reconciliation is complete.

PSE's plan to address the disposition of the gain in a separate filing is consistent with the Settlement Stipulation PSE entered into in Docket No. U-101217, which states:

> The agreement to a determination that the purchase price of $103,000,000 is "fair, reasonable and sufficient" does not and is not intended to affect the accounting treatment of the sale proceeds, and is not and does not affect an allocation of the sale proceeds as between PSE's customers and shareholders. The Parties understand and agree that such accounting treatment and allocation of the sale proceeds as between PSE's customers and shareholders are matters to be determined by the Commission <u>in a subsequent proceeding</u>. For avoidance of doubt, the $103,000,000 purchase price sets a ceiling for ratemaking purposes, without prejudice to any subsequent allocation of such sale proceeds to be recommended by

> any party or to be ordered by the Commission as between PSE's customers and shareholders.[7]

PSE's approach is also consistent with the Final Order in Docket No. U-101217, which states:

> PSE is required to maintain such separate accounts and accounting entries as are necessary to preserve fully the Commission's opportunity to consider in an appropriate proceeding the disposition of proceeds of sale and rate treatment of this transaction. As expressly provided in the Settlement Stipulation, the $103 million purchase price sets a ceiling for ratemaking purposes, without prejudice to any subsequent allocation of such sale proceeds to be recommended by any party or to be ordered by the Commission as between PSE's customers and shareholders.[8]

Q. How do you address concerns that the JPUD transaction needs to be addressed in the rate plan?

A. PSE expects the reduction in its electric delivery system costs associated with the transfer of assets to JPUD to be offset by a commensurate reduction in rate revenue. Therefore, it is not expected that such an adjustment in the aggregate will produce a material impact to the rate proposal in these dockets for PSE's remaining electric customers. Although the final reconciliation and impacts to rate base are not yet known, I have prepared Exhibit No. ___(KJB-15) which demonstrates support for this expectation. Exhibit No. ___(KJB-15) shows the estimated rate base per customer for JPUD customers leaving the system compared to the rate base per customer for the customers that will remain. The amounts reflected in Exhibit No. ___(KJB-15) are summarized as follows:

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[7] *In re Petition of Puget Sound Energy, Inc., For a Declaratory Order Regarding the Transfer of Assets to Jefferson County Public Utility District*, Docket U-101217, Settlement Stipulation ¶ 15 (December 15, 2010).

[8] *Id.* Order 03, ¶ 45.

Description		Total	JPUD	Remaining
Rate Base		2,621,991,642	41,329,316	2,580,662,325
Customer Counts	÷	1,085,350	18,356	1,066,994
Rate Base per Customer	=	$ 2,415.80	$ 2,251.54	$ 2,418.63

The above demonstrates that removing from rate base the amounts that are specific to the JPUD transaction on a per customer basis will have a negligible impact on the rate base per customer for the customers that remain.

Q. How will the transition be reflected in the decoupling mechanism?

A. As discussed above, the transfer of assets to JPUD will reduce the number of customers that PSE serves and will reduce the level of Allowed Revenue in the decoupling mechanism calculations.

Q. Do you agree with Mr. Deen's testimony that JPUD represents a "significant portion" of PSE's service territory?

A. No, as demonstrated above, prior to the transfer, PSE served just over 18,000 customers in Jefferson County, which represents roughly 1.7% of the electric customer base at June 30, 2012.

VII. PROPOSED K-FACTOR VALUES ARE REASONABLE

Q. Do you have any general observations with respect to the response testimony filed regarding the K-factor?

A. Yes. Several parties challenge the K-factor citing deficiencies with the proposed rate plan values. The following portion of my testimony will address their various concerns and demonstrate that even when calculating the K-factor based on their alternate approaches the values are greater than the 3.0 and 2.2 values agreed to in the settlement agreement. Therefore, their theories should be rejected and the proposed K-factors should be approved as stipulated in the settlement agreement.

Q. How do you respond to Public Counsel's testimony that the escalation factors provided in Exhibit No. ____(KJB-3) of the decoupling docket are "flawed" because they did not consider the impact of customer growth?

A. Public Counsel questions the historical growth factors used in the K-factor calculation because the Company did not consider the offset associated with customer growth. However, when analyzing the historic growth rates on a per customer basis, both the growth in rate base and depreciation expense resulted in K-factor values that were greater than the 3% and 2.2% proposed in the settlement. Exhibit No.____(KJB-16) provides the summary of the K-factor calculations utilizing compound growth rates reflected on a per customer basis. Pages two and three of the exhibit utilize the information originally presented in Exhibit No. ___(KJB-3) from the decoupling dockets which are then adjusted to calculate the growth rates on a per customer basis. The historical growth rate on a per customer basis for electric operations was 4.7% for non-production rate base and 5.3% for non-production depreciation expense for electric operations. Utilizing the customer adjusted growth rates results in a K-factor value of 3.44% for electric operations, which supports the conclusion that the proposed 3.0% K-factor is reasonable. Similar calculations were performed for gas operations and the historical compound growth rate was 3.5% for rate base and 3.1% for depreciation expense. The resulting K-factor value for gas operations would be

2.71%, which supports the conclusion that the proposed 2.2% K-factor is reasonable.

Q. How do you respond to Public Counsel's testimony that historical growth in rate base is not necessarily a good predictor of future growth?

A. Public Counsel witness Dittmer testifies that the historical growth in rate base will not likely continue because the net plant in service figures used in Exhibit No. __(KJB-5) in the decoupling dockets did not consider changes in accumulated deferred income taxes ("ADIT") nor did it consider the level of incremental rate base that would be addressed through customer growth.

Mr. Dittmer relies primarily on what he determines is "probable significant growth" in ADIT, likely relating to possible utilization of prior period net operating losses ("NOL"). However, as discussed in the Prefiled Rebuttal Testimony of Mr. Matthew R. Marcelia, Exhibit No. ___(MRM-1T), neither the level of accumulated deferred taxes, nor the timing of the use of NOL are certain, particularly when isolating to non-production electric and gas operations that are the basis of these proceedings.

Q. Have you estimated the level of rate base that is supported through customer growth?

A. Yes. Exhibit No. ___(KJB-17), which is described further below, presents a comparison of the level of incremental rate base that would be supported by forecasted customer growth and compares those balances to the estimated incremental net plant in service levels for the 2013 through 2015 period reflected in Exhibit No. ___(KJB-5) in the decoupling dockets. The comparison of columns C and D demonstrate that the incremental rate base forecasted for the 2013 to 2015 period will continue to outpace customer growth, even when considering incremental ADIT and NOL.

Q. Please explain Exhibit No. ___(KJB-17).

A. Exhibit No.___(KJB-17) presents the comparison of rate base supported by customer growth to the level forecasted based on the incremental change in net plant in service presented in Exhibit No. ___(KJB-5) in the decoupling dockets, after removing the estimated impact of non-production related ADIT.

Lines 1 through 3 on page one and two of the exhibit utilizes the ERF related rate base as of June 30, 2012 and calculates the embedded rate base per customer based on customer counts at June 30, 2012 for electric and gas operations respectively. The rate base per customer reflected on line three is applied to the forecasted customer counts to determine the level of rate base that will be supported by the forecasted growth. The incremental change in rate base supported by customer growth is presented in Column C.

Column D, presents the Incremental plant in service from Exhibit No. ___(KJB-5) in the decoupling dockets, after reducing the original figures for the estimated non-production plant related ADIT,

Column E utilizes the incremental net plant in service from Column D to estimate the level of rate base that will be in effect during the 2013 through 2015 period. Forecasted rate base for the 2013 through 2015 period, which is shown in Column

E, is calculated by adding the incremental net plant in service to the ERF related rate base shown on line 4.

Q. Have you addressed the impacts of the JPUD transition on the customer forecast for the 2013 through 2015 period?

A. Yes. As Mr. Dittmer discusses in his testimony, PSE's 2013 forecasted customers counts are lower because of the transition of customers to JPUD.[9] In order to alleviate any concerns that the rate base supported by customer growth forecast figures reflected in column C might be understated, I have adjusted the customer forecast to remove the impacts associated with the JPUD transition. To make this adjustment I added back the 18,356 JPUD customers to each of the 2013, 2014, and 2015 customer counts.

Q. Have you considered the possible reversal of the NOL related ADIT and the impact it could have on rate base during the 2013 through 2015 period?

A. Yes. Column F, on pages one and two of Exhibit No. ____ (KJB-17), evaluates the level of incremental rate base assuming that the ERF related NOL was reversed in 2013.

Q. By removing the NOL in column F, do you believe that the NOL will actually reverse in 2013?

A. No. As discussed in Mr. Marcelia's testimony, it is nearly impossible to forecast when the benefits associated with the NOL may reverse. However, for illustrative

[9] *See* Exhibit No. ___(JRD-1T) page 31, n. 33.

purposes, I have excluded the NOL, to demonstrate that even if the entire benefit associated with the NOL was to be utilized in 2013, the increase in forecasted rate base would still exceed the level supported through customer growth and therefore utilizing the historical trend is appropriate. Many of the parties speculated that the reversal of the NOL benefits would completely reverse the need for the K-factor, however this exhibit proves that their assumption is incorrect.

Q. Why is this significant?

A. The significance of the figures reflected in column G is that they demonstrate that despite customer growth or the "possible reversal of the NOL", incremental net plant additions will grow at a faster pace than customer growth and support the conclusion that earnings erosion will continue without the implementation of the proposed K-factor adjustments.

Q. How do you respond to Public Counsel's assertion that the development of the K-factor required a detailed attrition analysis?

A. Public Counsel is under the impression that the Commission requires a full attrition study to approve the K-factor rate plan. However, no such rules exist and a detailed attrition analysis is not necessary. In fact the Commission, when discussing attrition in the Final Order in Dockets UE-111048 and UG-111049, was "reluctant to be at all prescriptive in terms of establishing parameters defining how remedies might be fashioned and judged."[10]

The support provided for the K-factor meets the criteria outlined in footnote 673 of the Final Order, in which the Commission stated an attrition allowance is usually based on a combination of trended historical analysis showing for example, erosion of earnings coupled with some analysis of why such historical trends likely will continue. Both the prefiled direct testimony of Staff Witness Schooley and my prefiled direct testimony demonstrate that PSE has a long history of earning less than its authorized return and further analyzing why such historical trends likely will continue.

PSE's well documented history of under-earning presented in the prefiled direct testimony along with historical trend analysis based on commission approved levels of rate base and depreciation expense, reflected on a per customer basis, combine to show that the earnings erosion does indeed exist. The forecast provided in Exhibit No. ___(KJB-5) in the decoupling dockets and re-evaluated under various scenarios in this testimony as presented in Exhibit No. ___(KJB-16) and Exhibit No. ___(KJB-17), demonstrate the trend is very likely to continue. Therefore, the Commission can reasonably conclude a detailed attrition analysis would provide little additional benefit in these dockets. This evidence, coupled with protections established in the earnings sharing mechanism that will be triggered if PSE should exceed its authorized rate of return, meet the

[10] *WUTC v. Puget Sound Energy, Inc.* Dockets UE-111048 and UG-111049, Order 08 ¶ 491 (May 7, 2012).

parameters outlined in the Final Order in Dockets UE-111048 and UG-111049 and support the Commission's approval of the K-factor as proposed in the settlement agreement.

Q. How do you respond to Public Counsel testimony that the application of the K-factor in May of 2013 followed by a second application in January 2014 would lead to an overstatement of costs?

A. The application of the K-factor is intended to address the issue of chronic regulatory lag experienced when using historic data to set rates. It does so by mitigating the disparity between PSE's growth in delivery costs and growth in delivery revenues so that, over the course of the rate-effective period, PSE's total delivery revenues can match its total delivery costs and the utility has an opportunity to earn its authorized rate of return.

The K-factor is initially applied in mid-2013 to revenue per customer that is based on the level of costs experienced as of June 30, 2012.[11] This would theoretically bring PSE's revenues per customer in line with costs as of June 30, 2013. However, as reflected in Exhibit No. ___(KJB-17), the level of incremental rate base is substantially higher in 2013, and therefore the K-factor adjusted revenue per customer will still lag PSE's projected cost per customer for the remainder of 2013. Therefore, it is necessary to apply the K-factor again on January 1, 2014, to align PSE's revenue per customer to expected cost levels in 2014.

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[11] This ignores the fact that expenses are calculated in PSE's ERF on an average monthly basis, which means that expenses lag the end-of-period rate base used in ERF by six months.

Q. How do you respond to Nucor and Kroger's witness, Mr. Higgins critique of the K-factor?

A. Mr. Higgins asserts that the K-factor is not a stretch goal. To reach this conclusion he chooses a shorter time span (3.25 years) to evaluate growth rates and he inappropriately removes the NOL balance from the 2011 GRC results, stating that it "skews" the rate base figures. As discussed in Mr. Marcelia's testimony, removal of the NOL benefits (i) is one sided since PSE did not receive the tax benefit of bonus depreciation; (ii) would represent a normalization violation of the Internal Revenue Service Code, and (iii) is contrary to the Commission's direction regarding the appropriate treatment of the NOL in PSE's 2011 general rate case. As I discussed in my prefiled direct testimony, it is important to evaluate the growth rates over a period of at least five years to avoid the volatility and distortion that can occur over a shorter time horizon. However, it is interesting that the K-factor values produced in Mr. Higgins' analysis are 3.29 and 3.22 for electric and gas operations, which are higher than the values proposed in the settlement agreement.

Additionally, Mr. Higgins concludes that by using the shorter time horizon for rate base and depreciation expense escalation factors the proposed K-factor values are not stretch goals. However, Mr. Higgins fails to recognize that PSE's use of the CPI less the productivity factor rather than the Company's actual historical growth in O&M expenses does in fact represent an additional stretch goal. Historical growth in approved expense levels, calculated on a per customer basis, demonstrates increases of 4.7% for electric and 2.2% for gas, utilizing the 2006 through 2011 historical period. Despite this level of historical growth, the escalation factor for non-production plant related O&M is 1.9% during the rate plan, a level significantly below the actual historical growth experienced over the past five years. With O&M expense providing 50% of the weighting, the use of the CPI alone represents a stretch goal.

Q. How do you respond to Mr. Deen that the K-factor should be the full limit for delivery-related costs to natural gas customers?

A. Mr. Deen recommends that the 2.2% K-factor for natural gas be the "full limit for delivery costs" during the stay-out period, indicating that the "K-factor includes more than adequate headroom to accommodate delivery infrastructure replacement for safety purposes." Mr. Deen provides no support for his conclusion, aside from the statement that "the pattern of historical escalation includes all types of pipe replacement contemplated in the Commission's policy statement".

However Mr. Deen has missed the point of the Commission's Policy Statement in Docket UG-120715. The Commission intends to promote the <u>acceleration</u> of replacement of certain elevated risk pipe, primarily focusing on the replacement of Pre-1986 DuPont pipe. Limiting delivery costs to only the historical level of replacement investment would defeat the intent of the Commission's Policy Statement in Docket UG-120715.

Consistent with the policy statement, PSE will file its Pipeline Replacement Program Plan that will provide a master plan addressing the replacement of pipe with elevated risk pipe that will ultimately be subject to Commission approval.

To the extent it includes the acceleration of certain types of pipeline replacement beyond those currently assumed in the Company's forecasts, the Company may file an associated Cost Recovery Mechanism ("CRM") to address those costs. However, as stated in my prefiled direct testimony, any CRM filing would clearly differentiate the costs recovered through the CRM from those recovered through the decoupling mechanism's K-factor. Since the filing and approval of a CRM would be based an approved Pipeline Replacement Program Plan, any concerns that a CRM filing would include items covered in the K-factor could be addressed in the CRM filing.

VIII. GORMAN'S SUPPLEMENTAL TESTIMONY IS INCORRECT AND SHOULD BE REJECTED

Q. How do you respond to Mr. Gorman's supplemental testimony filed on May 7, 2013?

A. Mr. Gorman's supplemental testimony proposes that based on the calendar year 2012 CBR results that the ERF rate relief is "unwarranted". He states that based on the 2012 report that it is "not a certainty that PSE's rates are not already sufficient". To reach this conclusion he has proposed the same adjustments addressed previously in this testimony and the rebuttal testimony of Daniel A. Doyle, including proposed changes to authorized return on equity and relying on the GAAP capital structure instead of PSE's regulated common equity ratio. Additionally, since the filed CBR report does not provide the separation by recovery mechanism that is necessary to remove the PCA related costs, Mr. Gorman is effectively attempting to expand the scope of this proceeding.

Q. Do you have other concerns with Mr. Gorman's supplemental testimony?

A. Yes. Mr. Gorman's supplemental testimony was filed only one day prior to the date that rebuttal testimony was due, therefore the company has had limited opportunity to verify his calculations. However, Mr. Gorman implies on page 3 of his supplemental testimony that by reflecting the company's actual, higher cost of short term debt during the 2012 reporting period, that PSE has requested a change in the approved cost of debt. This is not true. PSE's ERF filing utilized the approved cost of capital and capital structure from the 2011 GRC.

IX. CONCLUSION

Q. Does this conclude your prefiled rebuttal testimony?

A. Yes.