EXHIBIT NO. ___(JHS-1T)
DOCKET NO. UE-11___/UG-11___
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-11____** **Docket No. UG-11____**

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

JUNE 13, 2011

PUGET SOUND ENERGY, INC.

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CONTENTS

PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Please state your name, business address, and present position with Puget Sound Energy, Inc.

A. My name is John H. Story. I am the Director of Cost and Regulation at Puget Sound Energy, Inc. ("PSE" or the "Company"). My business address is 10885 N.E. Fourth Street, Bellevue, Washington, 98009.

Q. Would you please provide a brief description of your educational and business experience?

A. Please see Exhibit No. ___(JHS-2).

Q. What topics are you covering in your testimony?

A. I present the electric results of operations and electric revenue deficiency. I will present the different allocation methods used to allocate common expenditures between electric and natural gas operations. I explain the various adjustments to the results of electric operations for the test year, plus changes to rate base, working capital, conversion factor and the overall revenue requirement and the resultant electric revenue deficiency. I will present a summary of the causes of the current revenue deficiency and the updated exhibits for the Power Cost Adjustment ("PCA") Mechanism. Finally, I discuss a proposal for a new schedule that would track a tax receivable.

The total requested electric revenue deficiency is $161,275,557, of which Firm Resale customers are allocated $164,930, Special Contract customers are allocated $429,485 and Retail sales are allocated $160,681,142. Based upon the adjusted test period revenues of $1,977,336,368 for retail sales, retail customers would receive an average 8.13% increase.

This increase does not reflect production tax credits ("PTC") or Treasury Grants which represent federal incentives associated with the wind turbines owned and being constructed by the Company. These federal incentives are provided to the customer through a separate rate schedule, Schedule 95A, that is not a general rate schedule.

II. TEST YEAR FINANCIAL STATEMENTS AND RATE BASE

Q. Would you please explain Exhibit No. ___(JHS-3)?

A. Exhibit No. ___(JHS-3) presents the actual financial statements for the test year. Page 3.01 of Exhibit No. ___(JHS-3) presents a comparison between the unadjusted electric income statement for the test year ending December 31, 2008 in Docket No. UE-090704 (the "2009 general rate case") and the unadjusted electric income statement for the 12 months ending December 31, 2010, the test year for this general rate case filing. Page 3.02 of Exhibit No. ___(JHS-3) presents the comparison of the two test years' balance sheet, page 3.03 of Exhibit No.___(JHS-3) presents the comparison of the two test years' rate base calculation and page 3.04 shows the comparison of the two test years' working capital calculation that is included as part of the rate base calculation. Page 3.05 of Exhibit No. ___(JHS-3) presents for the current filing the allocation methods, or factors, used in allocating common expenditures between electric and natural gas operations.

Q. Please describe page 3.05 of Exhibit No. ___(JHS-3).

A. Page 3.05 of Exhibit No. ___(JHS-3) presents the allocation methods, or factors, used in allocating common expenditures between electric and natural gas.

Common utility plant is that portion of utility operating plant that is used for providing more than one commodity, i.e., both electricity and natural gas service, to customers. Common plant includes costs associated with land, structures, and equipment, which are not charged specifically to electric or gas operations. The Company allocates its common utility plant for electric and gas by using the four-factor allocation method as authorized in the stipulation approving the merger of Puget Sound Power & Light Company and Washington Natural Gas Company. Components of the four-factor allocator include the number of customers, direct labor charged to operations and maintenance ("O&M"), Transmission and

Distribution O&M (excluding labor), and net classified plant (excluding general plant).

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

Q. Would you please explain pages 3.06 in Exhibit JHS-3?

A. As explained by Mr. Marcelia in his prefiled direct testimony, Exhibit No. ___ (MRM-1T), the impacts of (1) the change in tax method of accounting for repairs; and (2) the net operating loss related to bonus depreciation were not tracked separately in some of the Company's tax accounts during the test year. Mr. Marcelia provides a detail of the reallocation of the tax impacts of the repairs and retirements method changes and accelerated tax depreciation related net operating loss in his Exhibit No. __ (MRM-07). Page 3.06 shows the impact of this reallocation on the Company's balance sheet for 2010 and how the reallocation impacts the rate base and working capital calculations. These reallocations are necessary so that the dollars associated with the repairs and retirements method changes and depreciation related net operating loss can be tracked separately and treated appropriately for ratemaking purposes. Mr. Michael Stranik presents the equivalent schedules for natural gas operations in his Exhibit No. ___(MJS-3).

Q. Please explain the rest of the pages in Exhibit No. ___ (JHS-3).

A. Pages 3.07 through 3.09 show how the reallocation of the tax accounts explained on page 3.06 were added to the test year balance sheet, rate base and working capital calculation. The first column of numbers on each of these pages are the 2010 account balances prior to the reallocation, the next column shows what line items were impacted by the reallocation and the last column shows the result of the reallocation. This last column is what is used on pages 3.02 through 3.04 as the test year balance sheet, rate base and working capital calculation.

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

A. Yes. As explained earlier, they reflect the removal of the tax accounting change for repairs as directed by the Washington Utilities and Transportation Commission (the "Commission") in the 2009 general rate case, as well as the removal of a related tax method change for retirements.

Q. Has there been a change in electric rate base since PSE's most recent general rate case?

A. Yes. In the last general rate case filing actual electric rate base was $3,748.2 million. In this proceeding the electric rate base is $4,904.8 million after pro forma and restating adjustments, which is an increase of $1,156.6 million.

Q. What are the major causes of the increase in rate base since the last proceeding?

A. The majority of gross plant additions are attributable to new production plant totaling $726 million and new transmission and distribution facilities, totaling $403 million. Approximately 72 percent of the capital expenditures associated with these new transmission and distribution facilities were related to the replacement of existing infrastructure, which is discussed in Ms. Sue McLain’s direct testimony. Additionally the balance associated with deferrals has increased $258.8 million, primarily due to the Chelan Public Utility District ("PUD") contract payments and Lower Snake River transmission prepayments, which I will discuss later. These increases are offset by increased accumulated depreciation and deferred taxes.

For presentation purposes, we have highlighted a deferred tax account that is a tax asset that the Company has recorded for the net operating loss experienced in

2009 and 2010. Mr. Marcelia discusses this deferred tax in his prefiled direct testimony, Exhibit No. ___(MRM-1T). As explained by Mr. Marcelia, this net operating loss carry-forward creates a deferred tax asset which offsets the associated deferred tax liability for plant that has accelerated tax depreciation that created the tax loss. This deferred tax asset increases electric rate base by $23.2 million and natural gas rate base by $18.5 million based on the average of monthly averages of the account balances. Later in my testimony I will explain how the Company proposes to track the additions to, and reductions of, this net operating loss tax asset by using a new rate schedule. The Company is proposing this new schedule because this tax asset is expected to be used fairly quickly relative to the associated deferred tax liability, which is dependent on the economic life of the underlying asset.

Q. Do all of the investments in new plant generate new revenues?

A. No. The investment in replacement of existing assets does not generate new revenue; the Company does not earn a return on the incremental increase of new plant costs over the replaced plant until the replacement plant is included in rates. Ms. McLain explains in her testimony the types of investment that the Company is making in new plant and some of the impacts these new additions have on the Company's earnings. Generally this new investment will increase rate base by the difference between the cost of the new plant and net book value of the old plant. Depreciation will increase by the difference between the new plant's original cost less the old plant's original cost multiplied by the depreciation rate.

Q. Please explain the working capital calculation.

A. The working capital calculation is the measure, for ratemaking purposes, of investor funding of daily operating expenditures and a variety of non-plant investments that are necessary to sustain ongoing operations in order to bridge the gap between the time expenditures for services are required to be provided and the time cost recovery occurs. The purpose of this calculation is to provide a return on the funds the shareholders have invested in the Company for utility purposes that have not been accounted for elsewhere or that are not otherwise already earning a rate of return. The calculation is based on the average of the monthly averages of the actual amounts in the asset and liability accounts for these items during the test year.

The first part of the working capital calculation determines the total average invested capital that has been utilized during the test year. Because the Treasury Grant for the Wild Horse Expansion is required to be normalized under Section 1603 of the American Recovery and Reinvestment Act of 2009**,** the remaining balance of the Treasury Grant account is included in this portion of the working capital calculation in the same manner as Investment Tax Credits, which had similar normalization restrictions. The total average investments, which include electric, natural gas, non-operating investments and construction work in progress

("CWIP"), are deducted from average invested capital to calculate the total investor supplied capital.

The electric portion of working capital is calculated by taking the relationship of the total investor supplied capital to the total average investments, shown on line 88 of page 3.04 of Exhibit No. ___(JHS-3), multiplied by the electric operating investment. The electric working capital ratio is determined by deducting electric and natural gas construction work in progress from total average investments using the same methodology that has been approved in the 2009 general rate case.

The resulting electric working capital represents the investors' average investment, which is required to provide utility service and should earn the Company's rate of return. The working capital calculation is shown in Exhibit No. ___(JHS-3), page 3.04.

III. CAUSES OF THE ELECTRIC REVENUE DEFICIENCY

Q. Would you please describe the causes of the revenue deficiency?

A. Yes. To determine the major causes of the revenue deficiency between two regulatory filings the Company uses a unit cost analysis. A unit of cost is simply the major categories of the income statement and rate base that have the pro forma and restating adjustments for each of the regulatory periods, divided by the delivered load for that specific test period. This calculation determines the major categories' unit cost per kWh for the test period. The prior period that is used in this calculation is also adjusted for any restating and pro forma adjustments that were allowed in any interim regulatory filings between general rate cases, for example, a power cost only rate case ("PCORC"). There were no interim regulatory filings for electric service since the 2009 general rate case, so the prior period amounts are the approved amounts from that general rate case.

The differences between the current period and prior period unit costs are then 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 change and the associated revenue change.

Exhibit No. ___(JHS-8) shows the calculation for the difference between the adjusted test period for this general rate filing, as determined in Exhibit No. ___(JHS-4), and the 2009 general rate case compliance filing (excluding the Tenaska rider) that increased electric revenues effective April 8, 2010. The column labeled "Variance" shows the increase or decrease in revenue deficiency, or costs, since the last regulatory period.

Based on this calculation, cost changes include the following:

(i) $92.7 million decrease for production cost expenses which is the sum of lines 4, 15 and 17;

(ii) $18.2 million increase in customer and administrative/general expenses;

(iii) $12.9 million increase in transmission and distribution expenses;

(iv) $49.5 million increase in depreciation expense;

(v) $5.2 million decrease in other operating expense, amortization and property losses, due to amortizations of deferred costs for Goldendale and Wild Horse Expansion plant dropping off by the end of the rate year.

(vi) The change in rate base increases the revenue requirement by $191.4 million, of which approximately $25.1 million is related to the requested change in rate of return.

IV. ELECTRIC PRO FORMA AND RESTATING ADJUSTMENTS

Q. Please explain your Exhibit No. ___(JHS-4).

A. Exhibit No. ___(JHS-4) presents the impact of each of the pro forma and restating adjustments being made to the December 31, 2010 operating income statement and rate base. The first page of Exhibit No. ___(JHS-4), page 4.01, presents the unadjusted operating electric income statement and average of the monthly averages ("AMA") rate base for the Company as of December 31, 2010 (the test year), as presented in Exhibit No. ___ (JHS-3), pages 3.01 and 3.03, in the column labeled Actual Results of Operation. The various line items are then adjusted by the summarized pro forma and restating adjustments, shown in the third column. The fourth column is the adjusted results of operation for the test period, and this column is used to calculate the revenue deficiency. In the second to last column the revenue deficiency is added to the adjusted test period income statement. The impact on the operating income statement and rate base is presented in the final column, which shows that the net operating income divided by the test period rate base results in the requested rate of return.

Pages 4.02 through 4.05 of this Exhibit No. ___(JHS-4) present a summary schedule for all of the pro forma and restating adjustments. The first column of numbers on page 4.02 is the net operating income for the year ended December 31, 2010 and the rate base for the same period as presented on page 4.01. Each column to the right of the first column represents a pro forma or restating adjustment to net operating income or rate base. Each of these adjustments has a supporting schedule, which is referenced by the exhibit number and page shown in each column title.

The second to the last column, shown on page 4.05 of the summary schedule, summarizes all of the adjustments, and the final column shows the adjusted test period results, which can be used to calculate the revenue deficiency.

Q. Please explain your Exhibit No. ___(JHS-5).

All pages in Exhibit No. ___ (JHS-5) are the supporting schedules for adjustments directly related to electric operations.

Q. Please describe each adjustment, explain why it is necessary, and identify the effect on operating income or rate base.

A. I will explain the adjustments in the same order as they are shown on the summary schedule, by reference to the page number in each column and the title for each adjustment.

5.01 <u>Power Costs</u>

This schedule, shown on Exhibit No. ___(JHS-5), page 5.01, adjusts the test year to reflect the power costs that are projected to be incurred during the rate year (May 2012 through April 2013). The calculation of rate year projected power cost is explained in the Prefiled Direct Testimony of Mr. David E. Mills, Exhibit No. ___(DEM-1CT). The change in power cost between the 2009 general rate case and the current proceeding are shown in Exhibit No. ___(DEM-6) and in more detail in Exhibit No. ___(DEM-7C).

The costs associated with the credit facility supporting energy hedging are also included on this adjustment. In the 2009 general rate case filing, the electric services portion of the energy hedging credit facility costs were $311,301 and the costs in this proceeding are $1,420,907. As explained in the Prefiled Direct Testimony of Donald E. Gaines, Exhibit No. ___(DEG-1T), this increase is related to the higher costs of the current credit facility over the costs of the pre-merger credit facility requested in the 2009 general rate case filing, which credit facility would have expired in April 2012, prior to the rate year in this case. These costs are shown as line of credit costs in this adjustment and represent the electric services portion of the fees associated with having this facility.

Variable transmission income includes revenue earned under Open Access

Transmission Tariffs. Under the PCA Mechanism, these revenues are included in the power cost baseline rate to adjust the revenues to equal the most recent three year average after being adjusted for non-recurring items. There were not any non-recurring items in this test year so this is the current three year average.

The rate year power costs have been adjusted to test year power cost levels by the production factor discussed later in my testimony.

Q. Please explain Exhibit No. ___ (JHS-5) Page 5.01A.

A. Exhibit No. ___ (JHS-5) Page 5.01A presents the overview of all operating and maintenance costs for power production, provided by Mr. Mills, plus variable transmission income. As some of these costs are associated with other adjustments, this page is provided as a reconciliation page to Mr. Mills exhibits.

Q. Would you please explain the Jackson Prairie reclassification on Page 5.01A?

A. As discussed by Mr. Stranik in his Prefiled Direct Testimony Exhibit No. ___(MJS-1T), this excess capacity at Jackson Prairie began in November 2008, after the capacity at the Jackson Prairie facility was expanded. At the same time, PSE's gas for power portfolio, which is used to serve electric customers, was seeking storage capacity. This facilitated transactions for internal capacity agreements between natural gas and electric operations for the reservation of excess Jackson Prairie storage capacity.

Currently the gas book recognizes the gas storage rental revenues from the electrical book as a variable cost in the Purchased Gas Adjustment ("PGA") Mechanism. To align both sides of the transaction, the cost to the electric book needs to be classified as variable costs in the PCA Mechanism. The Company has made this change on schedule A-1 and has moved the $1.1 million cost for this item from production O&M, a fixed cost, to fuel, a variable cost.

Q. Would you please explain how the Company recovers the cost of major maintenance expense associated with natural gas turbines?

A. In the 2009 general rate case the Commission approved the "deferral method" of recovery. It is the Company's understanding that in the context of the 2009 general rate case proceeding the "deferral method" dealt with the deferral and amortization of major maintenance expense associated with natural gas turbines that have a long term service agreement ("LTSA") or contract service agreement ("CSA"). For natural gas turbines that do not have an LTSA, the parties were not in agreement as to the method to use. The Company had proposed the same methodology as used for natural gas turbines that have an LTSA and Commission Staff opposed this methodology.

In this proceeding the Company has included the test year amortization and deferrals of major maintenance associated with LTSA's ("contract major maintenance") in power costs. The Company is also proposing that this test year amortization be included in the power cost baseline rate on the production regulatory asset amortization line which is a variable cost line on Schedule A-1 in the PCA Mechanism. The return on the unamortized balance of the deferrals will be included in the regulatory asset recovery line, which is also designated as a variable line item. As the deferrals and amortizations change for LTSA, major maintenance during a given period, the actual costs will be shown on these lines for the actual PCA period. In this proceeding there is approximately $1.6 million of rate base and $1.2 million of amortization associated with this type of maintenance. These amounts are included on page 5.10, Regulatory Assets and Liabilities, discussed later in my testimony.

For maintenance on natural gas turbines that are not covered by an LTSA, the Company has used the actual maintenance expense from the test year. In this test year there is approximately $8.2 million of maintenance in this category. This cost is part of the fixed costs included in Hydro & Other Power on Line 19 of Schedule A-1. As major maintenance is incurred on natural gas turbines that are not covered under an LTSA, the cost associated with that major maintenance will be expensed as incurred.

Q. What is the total change to net operating income for the power cost changes being adjusted on page 5.01?

A. Net operating income is increased by $93,899,884 by the power cost adjustments.

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

A. Yes. The schedule, shown in Exhibit No. ___(JHS-9), and discussed later in my testimony, adjusts the PCA power cost baseline rate based on the pro forma and restating adjustments made to power costs and production plant. The methodology applied to calculate the power cost baseline rate is consistent with the Company's 2009 general rate case compliance filing except for the change associated with major maintenance on natural gas turbines that have an LTSA. Exhibit No. ___(JHS-9) also presents the updates for the other schedules used in the PCA Mechanism.

Q. Please continue describing the restating and pro forma adjustments.

A. The next adjustment is:

5.02 <u>Lower Snake River</u>

This pro forma adjustment presents the rate base and operating expenses associated with Phase 1 of the Lower Snake River Project. Located near Pomeroy, Washington, Phase 1 of the project has 149 wind turbines rated at 2.3 MW each resulting in 343 MW of wind generation. The expected output from this new generation plant has been included in the AURORA power cost model run for the rate year. This project is scheduled to be completed in April 2012. The in-service date, plant costs and expenses used in calculating this adjustment are provided by Mr. Garratt and are discussed in his prefiled direct testimony, exhibits and workpapers. The plant balance of $773,474,856, shown on line 3 of this adjustment, is the adjusted rate year plant cost for the project.

Q. Please explain how the rate base addition was calculated for rate purposes.

A. The projected total cost of construction of Phase 1 closing to plant between April and July 2012 was used for calculating the plant balance. This projected total cost of construction does not include amounts identified for contingency payments included in Mr. Garratt's exhibit or the Prepaid Transmission Expenses, which is presented in Adjustment 5.08, Lower Snake River Prepaid Transmission Deposits.

The total cost of capital investment calculated by month was used to determine the average of the monthly averages plant balance for the rate period. To calculate the depreciation expense, the approved depreciation rate of 4.24 percent for the Hopkins Ridge Wind Facility, a like-type plant, was used. The depreciation expense, calculated to the day assuming an April 15, 2012 in-service date, was accrued monthly, and the resulting monthly accumulated depreciation during the rate year was then averaged in the same manner as the plant cost. The accumulated depreciation balance of $17,848,252 is shown on line 4 of this adjustment.

Deferred taxes associated with the tax depreciation of the plant were calculated in the manner prescribed by Internal Revenue Code Regulations, Section 1.167(l)-1(h). For the Lower Snake River Project, the deferred tax calculation is based on five-year tax depreciation with an additional half-year Bonus Depreciation included in tax depreciation for the first year it is in-service. Additionally, as part of the American Recovery and Reinvestment Act of 2009, PSE is eligible to receive a U.S. Treasury Grant which results in a reduction to the tax basis for the Lower Snake River Project. The half year convention for tax depreciation, plus bonus tax depreciation of 50 percent in the first year, was used in determining the deferred tax liability for the rate year.

It is expected that the Company will be in a net operating loss position in 2012; therefore not all of the accelerated tax depreciation will be able to be used on the Company's tax return. The Company will not be able to recover the dollars associated with this accelerated tax depreciation until it has taxable income; therefore it would be a normalization violation to include the deferred tax liability as an offset against rate base. This is discussed in more detail in Mr. Marcelia's prefiled direct testimony, and the proposed rate treatment for the deferred tax asset that will be created by this net operating loss is discussed later in my testimony.

The total of all the adjustments described above increases rate base by $687,710,765.

Q. Please explain the other costs associated with the Lower Snake River Project on Exhibit No. ___(JHS-5) at page 5.02.

A. The calculation of total book depreciation expense of $32,938,780 shown on line 12 is explained above. The depreciation associated with the Treasury Grant tax basis reduction shown on line 11 is not tax deductible and is therefore excluded from the calculation of income tax expense on line 25. The power costs, wheeling and production O&M costs associated with the Lower Snake River Project are supported by the prefiled direct testimonies of Mr. Mills, Exhibit No. ___(DEM-1CT) and Mr. Roger Garratt, Exhibit No. ___(RG-1HCT) and their supporting exhibits and workpapers. Property taxes and insurance, also supported by Mr. Garratt, are projected for the rate year costs based on the costs for the plant. This adjustment decreases net operating income for electric operations by $39,435,507.

Q. Please explain the Treasury Grant.

A. The Treasury Grant is a subsidy provided by the U.S. government per Section 1603 of American Recovery and Reinvestment Act of 2009 for certain renewable energy projects. For wind projects, the Treasury Grant is an alternative to Production Tax Credits ("PTCs"), which some renewable development companies have not been able to use in a timely fashion. The Treasury Grant is equal to 30 percent of the qualifying investment and reduces the tax basis for accelerated tax depreciation by one half of the grant claimed.

For PSE, Treasury Grants are passed back to customers outside of general rates and the general rate case process, in Tariff Schedule 95A. Accordingly, the rate impact of the Treasury Grant is not included in this adjustment other than to include the impact of the tax basis reduction in the determination of tax depreciation.

Q. Please continue describing the restating and pro forma adjustments.

A. The next adjustment is:

5.03 <u>Lower Snake River Transmission Deposit</u>

On May 20, 2010, PSE filed an accounting petition with the Commission, Docket No. UE-100882, requesting regulatory treatment of the transmission deposits made to the Bonneville Power Administration ("BPA") associated with PSE's Lower Snake River Wind Project. The petition requests the Commission to authorize cost deferral accounting treatment related to prepayments made to BPA by PSE. The prepayments for which PSE seeks deferral treatment are being made to BPA to fund construction of certain transmission network upgrades including the new BPA-owned Central Ferry Substation required to interconnect the Lower Snake River Wind Project.

Although PSE has allocated the cost of the prepayment amongst all phases of the project, the regulatory treatment that PSE has requested in its petition and this proceeding is based on 100% of the prepayments. As discussed by Mr. Garratt in his prefiled direct testimony, PSE was required by BPA to prepay for the entire

1250 MW capacity of the substation, and for refund purposes BPA will not be tracking phases of construction of wind facilities separately. Under the terms of the Large Generator Interconnection Agreement between BPA and PSE, BPA must fully reimburse PSE the prepayment of the Network Upgrades within 20 years after the commercial operation date of the Network Upgrades. The full amount of the prepayment will be refunded with or without the build-out of the remainder of the generation project.

Prior to the 20 year refund deadline, BPA will return to PSE the prepayments related to the Network Upgrades, plus interest, by providing a monthly credit to PSE's future transmission bill. This credit will be equal to the point-to-point transmission tariff expenses associated with the use of the Interconnection Facilities and Network Upgrades.

In this proceeding PSE is requesting the same accounting treatment as detailed in its original accounting petition. The accounting petition requested that as of May 20, 2010, the date of the petition, the balance of the prepayments made to BPA would be treated as a deferred debit on which PSE will accrue and defer for later recovery at the currently allowed net of tax rate of return. Prior to May 20, 2010, the interest receivable from BPA has been recorded as a Company receivable from BPA and recorded as interest income. The interest subsequent to May 20, 2010 has been recorded in a receivable account with a corresponding entry to a customer payable account. This interest will be credited back to PSE customers as a reduction to future transmission expense when the interest is received from BPA in the form of transmission bill credits.

After these interest receivables are cleared, PSE will reduce the prepaid transmission deposit balance and interest receivable based on the continuing BPA transmission billings. Because BPA does not attribute the credit between principal and interest, but rather applies the full credit against the outstanding balance, which includes both principal and interest, PSE proposes to allocate the monthly credit first to the current month customer interest.

The remaining credit will then be allocated between the customers' interest receivable balance accrued from the date billing credits were first received and the transmission deposit principal balance using the ratio of each of those balances to the total due from BPA. The customer's portion of the BPA interest will be used to reduce transmission expense. The portion of the BPA credit allocated to principal will be used to reduce the principal balance associated with the Network Upgrades prepayments of $99,707,854, with an offsetting charge to transmission expense, until the full cost associated with the prepayments is recovered. These charges or reductions to transmission expense will be reflected in the PCA Mechanism.

The table below lays out the proposed accounting for this transaction based on the projected timeline that the BPA transmission credits for the prepayments and interest accrued will occur.

Date	Action	Proposed Accounting
Prior to May 20, 2010	Interest receivable from BPA - Company portion	Accrued as Company receivable and interest income is the offsetting account
Commencing May 20, 2010	Interest receivable from BPA – Customer portion	Company records rate of return on prepayments; Interest receivable from BPA recorded and liability for customer payable is the offsetting account
Commencing with in-service date (projected to be in 2012)	Transmission credits received from BPA equal to the demand portion of the Transmission Rate	BPA Credits offset Company interest receivable associated with interest prior to May 20, 2010; Credits then offset the interest receivable for customers. Customers receive credit against transmission expense in power costs as the interest is received
Commencing approximately February, 2014 and continuing until prepayments are recovered	Transmission credits received from BPA equal to the demand portion of the Transmission Rate	BPA Credit is first offset against current month interest due from BPA and is then allocated to the prepayment and interest accrued since the in-service date. Customers receive credit against transmission expense in power costs as the interest is received

Q. Please explain how the rate base addition was calculated for rate purposes.

A. As of March 2011, PSE has made $90.8 million in Network Upgrades prepayments to BPA, which are currently recognized in FERC account 186, Deferred Debits, and the Company is scheduled to make additional payments of $8.9 million, for total Network Upgrades prepayments of $99.7 million by August 2011.

For the rate year costs, PSE assumed the $99.7 million of prepayments was transferred to FERC 182.3 and included in rate base at the beginning of the rate year. The AMA balance of these prepayments during the rate year is shown on line 2 of the adjustment. During the rate year, the projected transmission credits are being allocated to PSE or customer interest receivable, and it is expected that none of the transmission credits will be available to pay down the transmission deposit balance. Therefore, there is no change in the balance of the regulatory asset in the rate year.

To calculate the carrying charges beginning May 20, 2010, the date of the accounting petition, the Company used the pre-tax authorized rate of return of 10.62 percent (6.9 percent divided by .65) from its 2009 general rate case. The carrying charges were accrued on the average monthly balance to the beginning of the rate year, and the resulting AMA balance of $17.0 million is shown on line 7 of the adjustment. The Company proposes to amortize these carrying charges over 25 years, which is the average service life of the underlying plant. The impact of this accounting methodology is to allow the Company to recover its costs associated with this transmission facility in the same manner as if the Company had constructed the facility and recorded AFUDC on the construction.

For book purposes, the carrying charges are included in current operating income as interest income. For tax purposes, this interest income is not included in taxable income until collected. The difference creates a deferred tax liability. The AMA balance of this deferred federal income tax is calculated through the rate year and is presented on line 9. This adjustment increases rate base by $110,538,909.

Q. Please describe the operating expense adjustment.

A. The calculation of amortization expense on the carrying charges totaling $680,129 in the rate year which is shown on line 16 is explained above. This adjustment decreases net operating income for electric operations by $442,084.

Q. Please continue with your explanation of the remaining adjustments.

A. The next adjustment is:

5.04 <u>Montana Electric Energy Tax</u>

This restating adjustment adjusts the test year amount of this tax to the amount that is projected to be incurred during the rate year based on the power generated at Colstrip. The fuel and operating and maintenance costs associated with this generation are reflected in the power cost adjustment.

This adjustment decreases net operating income for electric operations by $100,185.

5.05 Wild Horse Solar

This adjustment is a restating adjustment, which removes the effects of the solar project at Wild Horse. This power project is a demonstration project, and the Company is not requesting recovery of the costs associated with it at this time. This adjustment increases net operating income for electric operations by $179,073 and decreases rate base by $3,370,636.

5.06 Accounting Standards Codification ("ASC") 815

This restating adjustment removes the effect of ASC 815 (previously SFAS 133), which represents mark-to-market gains or losses recognized for derivative transactions. This accounting pronouncement is not considered for rate making purposes. This adjustment increases net operating income for electric operations by $108,519,513.

5.07 Storm Damage

This restating and pro forma adjustment reflects adjustment of the test year expense level of storm damage expense, $9.5 million, to the normal level of storm damage expense, which is based on the average of the most recent six years. The six-year average storm damage expense, $7.9 million, is used to determine the annual normalized expense allowed for ratemaking purposes and is consistent with prior general rate case filings.

The Company is requesting that the Commission maintain the level of IEEE defined storm expense for deferral purposes at the current $8.0 million. This is the threshold of annual IEEE related storm expenditures that would have to be met prior to the Company being able to defer IEEE related storm costs.

The second part of the storm damage adjustment amortizes the costs related to catastrophic storms that have been deferred. The new deferred costs associated with catastrophic storms that have not been approved for recovery in a prior rate case are shown on lines 25 and 26 and total $14.0 million. The remaining portion of the four year catastrophic storm deferral that was approved in the 2009 general rate case will be $16.1 million at the start of the rate year. This brings the total four year storm cost deferral to $30.1 million.

The last storm damage cost to be considered is the remaining portion of the December 13, 2006 wind storm deferral. The balance for this storm cost will be $51.7 million at the start of the rate year. This storm cost is being amortized over 78 months, which is the remaining portion of the 10 year amortization period that was approved in the Company's 2007 general rate case.

The effect of this adjustment is to increase net operating income by $1,349,514.

5.08 Tenaska Regulatory (Electric)

This restating adjustment removes the costs associated with the buy-down of the Tenaska fuel prices as determined in WUTC Docket No. UE-971619 and UE-031725. Since the 2009 general rate case, the costs associated with the Tenaska regulatory asset were recovered in a tracker, Schedule 133. The rates for Schedule 133 were updated in April, 2011 per WUTC Docket No. UE-110380 and are effective through December, 2011. As of December 31, 2011 the regulatory asset will be fully amortized and the Schedule 133 rate will be set to zero.

This adjustment removes the test year expenses associated with the Tenaska regulatory asset. The revenues associated with Schedule 133 are removed in Adjustment 6.02, Revenue and Expenses. This adjustment increases net operating income by $30,284,100 and decreases rate base by $56,496,129.

5.09 Chelan PUD Payments

PSE and Chelan PUD are parties to two separate cost-based power sales agreements under which PSE purchases significant portions of the aggregate output of the Chelan PUD's Rocky Reach and Rock Island hydroelectric projects on the Columbia River. These existing contracts are set to expire on October 31, 2011, for the output from Rocky Reach, and on June 7, 2012, for the output of Rock Island.

PSE and Chelan PUD executed a new agreement on February 3, 2006, that provides for the cost-based sale of 25 percent of the output of both the Rocky Reach and Rock Island projects to PSE. The new power sales agreement is for 20 years, commencing on November 1, 2011, for the Rocky Reach hydroelectric project and on July 1, 2012 for the Rock Island hydroelectric project.

As a condition of the contract, PSE is obligated to pay an upfront security deposit at the commencement of the power sales contract, November 1, 2011. The security prepayment is calculated by multiplying $740,000 by PSE's percentage of output multiplied by 100. At PSE's current percentage of 25%, the prepayment amount is $18.5 million. If PSE's percentage of the power sales increases due to the terms of the power sales agreement, PSE will have 30 days to increase the security deposit by the formula described above. If PSE fails to make any payment due under the power sales agreement, Chelan PUD would draw against the prepayment amount to satisfy such payment obligations. If Chelan PUD applies any prepayment amount to any payment due, PSE must replenish the amounts credited upon demand. Chelan PUD will apply any unused portion of the prepayment amount to the last payment due on the power sales agreement. No interest will be paid by Chelan PUD on the balance of the security deposit prepayment.

PSE was also obligated to make a one-time, upfront capacity reservation payment to Chelan PUD of $89 million. In Docket No. UE-060539, the Commission temporarily approved the Company's accounting petition to defer as a regulatory asset the one-time prepayment of $89 million to Chelan PUD, with interest accrued at PSE's net of tax rate of return. The Commission approved the prudence of PSE's entry into the Chelan contracts, the rate treatment for recovery of the capacity reservation payment, and the associated carrying costs through amortization over the 20 year life of the contracts in the final order in Docket No. UE-060266.

Q. Please explain how the rate base addition for the reservation payment was calculated for rate purposes.

A. The rate base for this rate year adjustment is calculated by using the actual reservation payment of $89 million, plus the carrying charges that will be accrued as of October 31, 2011 of $52.8 million, for a total balance of $141.8 million shown on line 2 of the adjustment. At the time the contract begins on November 1, 2011, accrual of carrying charges will cease, the combined balance of the reservation payment plus accrued carrying charges net of deferred federal income tax will be included in rate base, and the amortization of the balance over 20 years will begin. The accumulated amortization and deferred federal income tax reflected on Lines 3 and 4 represent the AMA balances for the rate year. This adjustment increases rate base by $117.1 million.

Q. Please explain how the rate base addition for the security deposit was calculated for rate purposes.

The $18.5 million security deposit shown on line 9 of the adjustment is assumed to be included in rate base at the beginning of the rate year at the average of the monthly averages for the rate year. Additionally, it is assumed that there will be no draws made by Chelan PUD on the security deposit; therefore, the asset balance throughout the rate year does not change. This adjustment increases rate base by $18.5 million. The total increase in electric rate base for the prepayment and security deposit is $135,630,302.

Q. Please describe the amortization of the reservation payment.

A. As explained previously, amortization expense for the reservation payment is calculated over the 20 year life of the contract and the amount included in this adjustment represents amortization expense for the rate year. This adjustment decreases net operating income by $4,607,243.

Q. Please continue describing the restating and pro forma adjustments.

A. The next adjustment is:

5.10 <u>Regulatory Assets</u>

Two new regulatory assets and liabilities are presented on separate adjustments: the Lower Snake River Prepaid Transmission, page 5.03, and the Chelan Contract

Payments, page 5.09. This pro forma adjustment adjusts all other production related regulatory assets and liabilities that are recovered through the PCA Mechanism. The amortization and the assets and liabilities on this adjustment, net of deferred federal income taxes, if applicable, are adjusted to their projected rate year amounts and average of the monthly averages balances as agreed to in the PCA Settlement from PSE's 2001 general rate case.

An exception to this rate year treatment is the amortization and rate base on the contract major maintenance regulatory assets that are shown on Lines 17 through 21, and 38 through 42, and were discussed in the power cost adjustment. As discussed earlier, the Company has included the test year amortization and deferrals of major maintenance associated with LTSA's ("contract major maintenance") at their test year amounts. The Company is proposing that the amortization for this item be added to the power cost baseline rate that is shown on Schedule A-1 in the PCA Mechanism and will be designated as a variable cost. The return on the unamortized balance of these deferrals will also be included in an appropriate variable cost line item. As the deferrals and amortizations change for this type of major maintenance during a given period, the actual costs and return will be shown on their respective lines for the PCA period true up. As new major maintenance items are completed they will be added to Schedule A-1, and as amortization is completed the associated major maintenance item will be removed.

The new regulatory assets and liabilities since the 2009 general rate case are discussed below. All other items on this adjustment were included in prior general rate cases and are represented in the manner allowed for recovery.

1. <u>Westcoast Pipeline Capacity Payment UE-100503 – Lines 11 and 32.</u> This adjustment relates to a deferred credit for a $4.6 million payment from BNP Paribas Energy Trading Canada Corp. (formerly FB Energy Canada Corp.) in exchange for PSE’s assumption of BNP’s contractual benefits and obligations related to additional natural gas transportation capacity on the Westcoast Energy, Inc. (“Westcoast”) pipeline that was formerly held by BNP. Regulatory treatment for this liability was approved in WUTC Docket No. UE-100503. The amount of the increases to rate base of $189,664 was determined by amortizing the capacity payment starting April 1, 2010 through October 31, 2018, which is the life of the underlying contract. The rate year average of the monthly averages balance net of deferred federal income tax was then compared to the test year average of the monthly averages balance. Adjusting for the annual amortization based on the 103 month contract period decreases operating expense by $134,407.

2. <u>Colstrip Units 1 and 2- prepayment – Lines 14 and 35.</u> On March 21, 2007, PSE made a non-refundable reservation dedication payment of $5 million (PSE’s share) to Western Energy Company ("WECo") that will assure the coal sales by WECo are limited to an existing contract that expired on

December 31, 2010. The new contract period began January 1, 2010 and expires December 31, 2019, at the earliest. This reservation dedication payment was booked to FERC 165, Prepayments. This item is included in production rate base. The reservation payment is being amortized over nine years beginning January 2011 as discussed by Mr. Jones in his prefiled direct testimony, Exhibit No. ___ (MLJ-1T). The average of the monthly averages for the rate year for this regulatory asset, which totals $1,018,519, decreases rate base. Amortization expense on this regulatory asset occurring in the rate year increases operating expense by $555,556.

3. FERC Part 12 Study Non Construction Costs UE-070074 - Line 15 and 36. On May 28, 2008, the Commission issued its order allowing PSE to recover non-construction related regulatory study costs based on an amortization period of five years for the costs incurred between January 8, 2007 through December 31, 2010. These regulatory studies are required by FERC under the Code of Federal Regulations, Part 12 (FERC Part 12), concerning Safety of Water Power Projects and Project Works, to maintain the Company's licenses for hydroelectric plants. Under this regulation, FERC has required PSE to perform studies related to Probable Maximum Flood flows and reservoir elevations based on Probable Maximum Precipitation for both Baker Project reservoirs. The final non-construction costs as of December 31, 2010 were $1.3 million. The average of the monthly averages for the rate year for this regulatory asset, which totals $1,193,198, increases rate base. Amortization

expense on this regulatory asset occurring in the rate year increases operating expense by $265,155.

4. Contract Major Maintenance – assets and amortization on Lines 17 through 21 and Lines 38 through 42 were discussed previously.

5. Renewable Energy Credits "RECS".

In Order 06, Paragraph 17 of Docket No. UE-070725, the Commission stated:

> In future general or power cost only rate case filings, and after completion of the REC/PTC offset period, the Company will offset the REC liability against rate base and amortize the balance of RECs at the beginning of a given rate year over five years as a credit to cost of service. The rate base impact of the REC liability will be calculated using the same methodology used for regulatory assets related to production.

RECs have not been included as a regulatory liability at the time of this filing as the REC/PTC offset period is not expected to end until the beginning of 2012. During the course of this proceeding, as the rate year balance of the REC liability becomes more certain, PSE will include the known and measurable AMA balance in electric production rate base as appropriate.

All amounts discussed above are pre-tax and are before the application of the production adjustment.

The overall effect on this adjustment is to increase net operating income for electric operations by $3,683,316 million and decrease rate base by $19,546,418.

5.11 Production Adjustment

This pro forma adjustment decreases production related rate base and certain production expenses by the production factor that was used for calculating power costs. This adjustment is applied to production related items so that the growth in load from the test year to the rate year will provide an increase in revenues to cover the projected rate year level of production expenses. The production factor is based on the ratio of the test period normalized delivered load to the rate year delivered load, which is 97.901%. The complement of this amount, or 2.099%, is the production factor that is used in the adjustment itself.

Included in the production factor calculation is the 234,916 MWh increase to test year load for the weather normalization adjustment discussed in Adjustment 6.01 below. The application of this adjustment is consistent with how the production expenses have been calculated in prior general rate cases and power cost only rate cases.

This adjustment increases net operating income for electric operations by $2,294,360 and decreases rate base by $50,346,992.

Q. Please explain your Exhibit No. ___(JHS-6).

All pages in Exhibit No. ___ (JHS-6) are the supporting schedules for adjustments related specifically to common adjustments and therefore relate to both electric and natural gas operations. Each of the individual adjustments will be addressed in the specific witness testimonies as indicated in the table below:

Adjustment	John H. Story Exhibit No. (JHS-1T)	Michael J. Stranik Exhibit No. (MJS-1T)	Matthew R. Marcelia Exhibit No. (MRM- 1T)	Chun K. Chang Exhibit No. (CKC-1T)
6.01 Temperature Normalization				x
6.02 Revenue and Expenses	x	x		
6.03 Pass Through Revenue and Expense	x	x		
6.04 Federal Tax			x	
6.05 Tax Benefit of Pro forma Interest			x	
6.06 Operating Expenses	x	x		
6.07 General Plant Depreciation		x		
6.08 Normalize Injuries and Damages		x		
6.09 Bad Debt	x			
6.10 Incentive Pay	x			
6.11 Property Taxes			x	
6.12 Excise Tax & Filing Fee		x		
6.13 D&O Insurance		x		
6.14 Interest on Customer Deposits		x		
6.15 Rate Case Expenses	x			

6.16 Deferred Property Gains/Losses		x		
6.17 Property & Liability Insurance		x		
6.18 Pension Plan		x		
6.19 Wage Increase	x			
6.20 Investment Plan	x			
6.21 Employee Insurance	x			

Q. Please describe each adjustment, explain why it is necessary, and identify the effect on operating income or rate base.

A. I will explain the adjustments in the same order as they are shown on the Exhibit No. ___ (JHS-4) summary schedules, by reference to the page number in each column and the title for each adjustment.

6.01 <u>Temperature Normalization</u>

This adjustment, as shown on Exhibit No. ___(JHS-6), page 6.01, restates test year delivered load and revenue to a level that would have been expected to occur had the temperatures during the test year been "normal". The difference between the actual test year Generated, Purchased and Interchange ("GPI") load and the temperature normalized GPI megawatt hours ("MWH") is adjusted for system losses. The result of this calculation is then allocated to the rate classes. The revenue impact based on the applicable end step energy rate for each rate class is then calculated.

The test year was warmer than normal requiring an adjustment to net operating income to bring revenues up to what would have occurred under normal conditions. The temperature load adjustment increases actual GPI by 252,056 MWH, or 234,916 MWH when adjusted for line losses. The Prefiled Direct Testimony of Dr. Chun K. Chang, Exhibit No. ___(CKC-1T), discusses the Company's weather normalization methodology and the allocation to the rate classes based on the proposed rate class level weather normalization methodology.

After allocation to the different customer classes, this adjustment increases net operating income for electric operations by $12,971,429.

6.02 General Revenues

This is a pro forma and restating adjustment, shown in Exhibit No. ___(JHS-6), page 6.02, which adjusts the test year revenues to the revenues that would have been collected during the test year if the tariffs from the 2009 general rate case had been in effect during the entire test period. These adjusted test year revenues are included in line 3.

This adjustment also adds back to revenues the PTCs associated with the wind plants, as this credit is not a general tariff. The income tax credit associated with the PTCs is removed in the federal income tax calculation on Page 6.04.

This adjustment also removes the credits passed back to customers associated with the Merger Rate Credit (Schedule 132) on line 7 and Regulatory Asset Tracker (Schedule 133) on Line 8.

Pole attachment revenues are trued up for rate changes and contract changes during the test period on line 26. Other adjustments to revenues (on lines 4, 6, 9, 27 and 28) relate to reclassifications and miscellaneous out-of-period price changes for all sales customers.

Finally, included on this adjustment is the removal of the expense associated with creating the regulatory liability associated with PTCs that was recorded during the test year. Because Schedule 95A was set to zero for PTCs, this expense is the contra-account for the PTC credit to taxes that is recorded each month.

This adjustment increases net operating income for electric operations by $1,490,395.

6.03 <u>Pass-through Revenue and Expense</u>

This is a restating adjustment that removes from operating revenues all rate schedules that are a direct pass through of specifically identified costs or credits to customers, such as the conservation rider, municipal taxes and the low income program. The associated expense that is recorded in the test year for these direct pass through tariffs are also removed in this adjustment.

For electric operations, the revenues and expenses associated with the residential exchange benefits provided by the Bonneville Power Administration and the electric green power program are removed. The portion of the green power program recorded in power costs has been removed in the power cost page, Exhibit No. ___(JHS-05), page 5.01. REC revenues passed back to customers under Schedule 137 have been removed as well as the associated expense that was recorded to FERC 456 to recognize the recording of the regulatory liability for PTCs, which were being recovered as authorized in WUTC Docket Nos. UE-070725 and UE-101581.

This adjustment decreases net operating income by $306,445.

6.04 Federal Income Taxes

This schedule adjusts actual federal income tax ("FIT") expense to the test year for this case. Mr. Matthew R. Marcelia discusses this adjustment in his prefiled direct testimony, Exhibit No. ___(MRM-1T). This adjustment includes the removal of the income tax credit associated with the PTC revenues that were removed in adjustment 6.02 discussed earlier. The impact of this restating adjustment, shown on Exhibit No. ___(JHS-6), page 6.04, is to decrease net operating income by $60,471,550.

Q. Are there any changes to the Federal Income Tax Adjustment since the 2009 general rate case?

A. Yes, previously the Company had included all interest associated with the test year as a deduction to taxable income and then corrected the interest deduction to reflect only interest associated with rate base in Adjustment 6.05 Tax Benefit of Pro Forma Interest. To eliminate the need to include the test year interest in two separate adjustments, the Company is now handling the entire adjustment for tax benefit of interest in Adjustment 6.05. This change does not affect the overall revenue requirement from what would have been calculated in the former presentation; it just moves the interest deduction from the Federal Income Tax Adjustment to the Tax Benefit of Pro Forma Interest Adjustment.

Q. Please continue describing the restating and pro forma adjustments.

A. The next adjustment is:

6.05 <u>Tax Benefit of Pro Forma Interest</u>

This pro forma adjustment, shown on Exhibit No. ___(JHS-6), page 6.05, uses a rate base method for calculating the tax benefit of pro forma interest. Please refer to the Prefiled Direct Testimony of Matthew R. Marcelia, Exhibit No. ___(MRM-1T), for an explanation of this adjustment. This adjustment increases net operating income for electric operations by $55,619,944.

6.06 **Operating Expenses**

This pro forma and restating adjustment adjusts the test year for several different items. Please refer to the Prefiled Direct Testimony of Michael J. Stranik, Exhibit No.___(MJS-1T), for the adjustments that are common to both natural gas and electric operations, shown on lines 4 through 10 and line 12, which result in a decrease to operating expenses of $848,264. I will discuss the three adjustments on lines 2, 3 and 11 that are related to electric service only.

Removal of Wild Horse Expansion and Mint Farm costs deferrals – The impact of the journal entries to set up the Wild Horse Expansion and Mint Farm deferrals is removed. The items on lines 2 and 3 remove the entries that occurred prior to the April 2010 effective date of the Final Order in PSE's 2009 general rate case and increase test year operating revenues by $5.36 million for electric operations.

FERC Land Use Fee Accrual – On January 4, 2011, the U.S. Court of Appeals for the District of Columbia Circuit ruled against a 2009 FERC notice that would have significantly increased the public land rental fees FERC collects from hydropower projects on federal lands. Prior to and during the test year, PSE had been accruing land use fees at the increased rental fees. Based on the ruling, PSE made a correcting entry to adjust expenses for lower land use fees. The correction included periods prior to the test year. The adjustment on line 12 is removing the portion of the correcting entry related to prior periods. This adjustment decreases operating expenses by $655,971for electric operations.

This adjustment decreases net operating income for electric operations in total by $3,359,172.

6.07 General Plant Depreciation

This restating adjustment removes depreciation that relates to a prior period adjustment to depreciation expense for a calculation error in the fixed asset system for general plant assets, FERC Accounts 391-398. Please refer to the Prefiled Direct Testimony of Michael J. Stranik, Exhibit No.___(MJS-1T), for the detailed discussion on this adjustment. This adjustment increases net operating income for electric operations by $688,453 and decreases rate base by $233,769.

6.08 Normalize Injury and Damages

This restating adjustment normalizes injuries and damages for the test year. Please refer to the Prefiled Direct Testimony of Michael J. Stranik, Exhibit No.___(MJS-1T), for the detailed discussion on this adjustment. This adjustment decreases net operating income by $725,618, for electric operations.

6.09 Bad Debts

Consistent with prior cases, this restating adjustment calculates the appropriate bad debt rate by using the average bad debt percentage for three of the last five years after removing the high and low years that apply to electric and natural gas operations. Since it takes four months to write-off a bill, the ratio of the write-off versus revenue is offset four months. For example, a write-off booked in December 2010 actually related to revenue that was recognized during the twelve months ending August 2010. Using this relationship between August revenues and December write-offs results in the calculation of an appropriate percentage of write-offs associated with revenues. The bad debt percentage for a given year is calculated by taking the actual write-offs for that year and dividing them by the net revenues for twelve months ending in August for each of the years. The net test year revenues are multiplied by the calculated average bad debt percentage to determine the amount of restated bad debt expense. This amount is compared to the actual test year level of bad debt expense to determine the effect on income. This bad debt percentage is also used in the conversion factor when determining the final revenue requirement.

This adjustment increases net operating income for electric operations by $1,638,181.

6.10 <u>Incentive Pay</u>

This restating adjustment uses a four-year average of incentive compensation paid to employees and is allocated between electric and natural gas operations. In his testimony, Mr. Hunt discusses why this expense is appropriate for ratemaking consideration and how the program is similar to the previously allowed incentive compensation programs. Officer incentive pay is excluded from the calculation in the current rate case as discussed by Ms. Harris in her prefiled direct testimony Exhibit No. ___(KJH-1T).

For this calculation, the Company has used the payouts which occurred during March of the years 2008 through 2011 for the calendar years 2007 through 2010 and allocated the four-year average to electric and natural gas using the labor benefit assessment distribution allocator. The incentive payment is allocated to O&M expense and other accounts based on where payroll was charged during the test year. This adjustment increases net operating income for electric operations by $482,220.

6.11 <u>Property Taxes</u>

This pro forma adjustment reflects the projected property tax rates to be paid based upon the test year property values. Please refer to the Prefiled Direct Testimony of Matthew R. Marcelia, Exhibit No. ___(MRM-1T), for an explanation of this adjustment.

Q. Are there any changes to the property tax calculation approved in the 2009 general rate case?

A. Yes, the calculation approved in the 2009 general rate case used property taxes associated with the 2007 property values and not the test year 2008 property values. Commission Staff proposed this change to the long-standing method of calculating property taxes that had been accepted by this Commission. Please refer to the Prefiled Direct Testimony of Matthew R. Marcelia, Exhibit No.___(MRM-1T), for an explanation of this adjustment and why the methodology as filed by the Company in this proceeding is the appropriate method to determine property taxes for the test year. In this adjustment, the property on which the tax is calculated is the property owned by PSE as of December 31, 2010. This adjustment decreases net operating income by $3,359,921.

Q. Please continue describing the restating and pro forma adjustments.

A. The next adjustment is:

6.12 <u>Excise Tax and Filing Fee</u>

This restating adjustment adjusts the test year to the actual expense for Washington State excise tax and the WUTC filing fee that should be recorded for these costs. This adjustment decreases net operating income for electric operations by $200,979.

6.13 <u>Director and Officer Insurance</u>

This restating adjustment removes the portion of Directors and Officers insurance that should be allocated to Company subsidiaries. Please refer to the Prefiled Direct Testimony of Michael J. Stranik, Exhibit No.___(MJS-1T), for the explanation of this adjustment. This adjustment increases net operating income for electric operations by $33,584.

6.14 Interest on Customer Deposits

This pro forma adjustment adds to operating expense the cost of interest for this item based on the most currently implemented interest rate. Please refer to the Prefiled Direct Testimony of Michael J. Stranik, Exhibit No.___(MJS-1T) for the explanation of this adjustment. This adjustment decreases net operating income for electric operations by $47,159.

6.15 Rate Case Expenses

Consistent with prior rate cases, the Company has used the history of expense levels for power cost only rate cases and general rate cases to determine a normalized level of expenditures by averaging the costs associated with the last two general rate cases as one calculation and the last two power cost only rate cases as another calculation. The average cost for a general rate case using this methodology is $1.964 million. This cost is allocated 50 percent to electric and 50 percent to natural gas, which results in a $982,000 average cost for each energy group. The average cost for a power cost only rate case is $329,000.

Each average cost is then normalized for recovery over a time period based on the frequency of filings experienced in the recent past. The average costs for a general rate case are normalized for recovery over two years and the average costs of a power cost only rate case are normalized over four years. These normalized amounts are then compared to the amount the Company had actually recorded in the test year for each type of rate case expense.

This adjustment increases net operating income for electric operations by $44,411.

6.16 Deferred Gain/Loss on Property Sales

This restating and pro forma adjustment provides the customer with the gains and losses from sales of utility real property since the last general rate case. Please refer to the Prefiled Direct Testimony of Michael J. Stranik, Exhibit No.___ (MJS-1T), for the detailed discussion of this adjustment. This adjustment decreases net operating income for electric operations by $1,028,316.

6.17 Property and Liability Insurance

This pro forma adjustment reflects the actual premium increases for property and liability insurance expense. These costs are allocated between electric and natural gas operations depending on the purpose of the insurance. Please refer to the Prefiled Direct Testimony of Michael J. Stranik, Exhibit No.___(MJS-1T), for the detailed discussion on this adjustment. This adjustment decreases net operating income for electric operations by $124,477.

6.18 Pension Plan

This restating adjustment calculates pension expense based on a four year average of cash contributions to the Company's qualified retirement fund and removes the Supplemental Executive Retirement Plan expense from test year expense.

Please refer to the Prefiled Direct Testimony of Michael J. Stranik, Exhibit No.___(MJS-1T), for the detailed discussion of this adjustment. This adjustment decreases net operating income for electric operations by $1,199,984.

6.19 Wage Increase

This pro forma adjustment reflects the impact of wage increases and payroll tax changes, as described in the Prefiled Direct Testimony of Thomas M. Hunt, Exhibit No. ___(TMH-1T). For represented (union) employees, the adjustment reflects the known annual wage increases that were granted in the recently approved contracts for the International Brotherhood of Electrical Workers ("IBEW") and United Association of Plumbers and Pipefitters ("UA") union employees. The contract for IBEW-represented employees runs from September 1, 2010 through March 31, 2014. The percentage of wage increases for IBEW union employees from the test period through the rate year includes 2 percent effective April 1, 2011; 2.25 percent effective April 1, 2012; and 2.5 percent effective April 1, 2013. The wage increase in 2013 is only in effect for one month of the rate year; therefore the adjustment reflects 1/12 of the 2013 increase. The compounded wage increase for IBEW during this time frame is 4.51 percent.

The percentage of wage increases for UA union employees from the test period through the rate year includes 1 percent effective in January 1, 2011; 3 percent effective January 1, 2012; and 3.75 percent effective January 1, 2013. The contract for UA represented employees runs from October 1, 2010 through September 30, 2013. The wage increase in 2013 is only in effect for four months in the rate year; therefore the adjustment reflects 4/12 of the 2013 increase. The compounded wage increase for UA during the time frame is 5.33 percent.

The average percentage of wage increase used in the wage adjustment for non-union employees includes only the known wage increase of 3.24 percent that was paid effective March 1, 2011. This increase has been weighted by prior year actual salary increases, as in prior general rate cases. This is done in order to account for "slippage," as it is sometimes called, that occurs when new non-union employees are hired at lower salary rates than the more senior employees they are replacing.

Q. Please explain how these management increases are weighted by prior increases in order to adjust for slippage.

A. Slippage is determined by measuring the difference between the average wage increase granted during each of a number of historical adjustment periods and the change between the average wage at the beginning and end of each of the same periods for the same class of employees. Projected wage increases for the same class of employees are then weighted, or reduced, by the slippage differential.

In order to perform the actual slippage calculation in this case, the Company first calculated the annualized payroll for all non-union employees for each of the last five years as of March 1, which is the effective date of annual non-union salary adjustments. From this, the Company determined the average annual salary per non-union employee and calculated the actual percent increase for the years 2007 to 2010, and compared this to the projected percent wage increase for non-union employees. Average salary change per non-union employees as of March 1st for the years 2007 through 2010 was 4.42%, 1.29%, 3.53% and a negative 0.24%, respectively, or 2.31% on average. This was compared to the average wage increase allowed for non-union employees during those same years of 3.02%, 3.41% and 3.34% and 0.00%, respectively, or 2.52% on average. The 2.31% average change in wages between the beginning and end of each adjustment year is 91.58% of the 2.52% average wage increase given at the beginning of each year. This percentage is applied to the wage increase for March 31, 2011 of 3.24% to yield an effective wage increase of 2.97% as a result of slippage.

Q. What payroll taxes are included in the adjustment?

A. The payroll taxes included in the adjustment are Social Security (Federal Insurance Contribution Act/FICA), Medicare, Federal Unemployment Tax (FUTA) and State Unemployment Tax (SUTA).

Q. How are the payroll taxes for the wage adjustment calculated?

A. The Medicare Tax applies the actual 1.45 percent tax rate to the wage increase. FICA, FUTA and SUTA tax calculations include wage limits where the payroll taxes are only calculated up to the wage limit of the employee. Accordingly, the payroll taxes on FICA, FUTA and SUTA in this adjustment are calculated by employee to test for the wage limits. The payroll tax wage limits and tax rates are as follows:

PAYROLL TAX	WAGE LIMITS	TAX RATE
FICA	$106,800	6.20%
FUTA	$7,000	0.60%
SUTA	$37,300	1.89%

Q. Were there any offsets included in the wage increase calculation?

A. Yes, the Company made two adjustment to the wage increase calculation: (1) in adjustment 6.06 Operating Expenses, the Company removed test year O&M labor of those employees that were laid off in 2010; and (2) wage increases on executive's salaries were not included as part of the wage increase calculation.

Q. What is the overall impact of this adjustment on net operating income?

A. This adjustment decreases net operating income for electric operations by $2,138,614.

Q. Please continue describing the restating and pro forma adjustments.

A. The next adjustment is:

6.20 <u>Investment Plan</u>

This pro forma adjustment adjusts the Company portion of investment plan expense to reflect the additional expense associated with the wage increases and is based on the current employee contribution rates. This adjustment decreases net operating income for electric operations by $107,798.

6.21 <u>Employee Insurance</u>

This pro forma adjustment adjusts the test year insurance expense to the expected average cost per participant for the rate year. The average cost negotiated in the UA employment agreement effective October 1, 2010 is $953 for 2011, which is unchanged from the preceding contract period. Test year average cost per participant based on average participant count was $953 for IBEW employees, $988 for UA employees and $998 for non-union employees. The higher average cost per participant for UA and Non-Union employees was due to participants choosing a higher cost mix of benefits, for instance employee plus family as opposed to employee only, than what was used to calculate the negotiated average. For a detailed discussion of the employee benefit program, please refer to the Prefiled Direct Testimony of Thomas M. Hunt, Exhibit No.____(TMH-01T).

The pro forma insurance expense is allocated to electric and natural gas based on the labor benefit assessment distribution allocator from Exhibit No. ___(JHS-3), page 3.05 and then to O&M based on payroll distribution.

The effect of this adjustment is to decrease net operating income by $81,749.

V. CALCULATION OF THE ELECTRIC REVENUE DEFICIENCY

A. Revenue Deficiency Based on the Pro Forma and Restated Test Period

Q. Would you please describe Exhibit No. ___(JHS-7)?

A. Exhibit No. ___(JHS-7) presents the calculation of the revenue deficiency based on the pro forma and restated test period. The individual pages in Exhibit No. ___(JHS-7) are:

7.01 General Rate Increase

This schedule shows the test period pro forma and restated rate base, line 1, and net operating income, line 6. Based on $4,904,756,946 invested in rate base, a 8.42% rate of return and $312,868,894 of net operating income, the Company would have an overall revenue deficiency of $161,275,557. After allocation to wholesale and special contract customers, the deficiency attributable to retail customers is $160,681,142.

7.02 Cost of Capital

This schedule reflects the proposed capital structure for the Company during the rate year and the associated costs for each capital category. The capital structure and costs are presented in the Prefiled Direct Testimony of Donald E. Gaines, Exhibit No. ___(DEG-1T). The rate of return is 8.42 percent and 7.29 percent net of tax.

7.03 Conversion Factor

The conversion factor is used to adjust the net operating income deficiency for revenue sensitive items and federal income tax to determine the total revenue deficiency. The revenue sensitive items are the Washington State utility tax, Washington Utilities and Transportation Commission annual filing fee, and bad debts. The conversion factor used in the revenue requirement calculation, taking into consideration the adjustments discussed earlier, is 0.620749 for electric operations.

Q. Is the Company requesting in this filing that any deferred Power Cost Adjustment expenses be included in rates in addition to the general rate increase?

A. No. The deferred costs do not exceed the trigger amount necessary to request an increase or refund of power costs, and it is not expected at this time that this threshold will be met during the course of this proceeding.

B. <u>Calculation of the Power Cost Baseline Rate for this Proceeding</u>

Q. Is the Company proposing a power cost baseline rate in this case consistent with the calculation of the power cost baseline rate in the 2009 general rate case?

A. Yes, the Company's proposed new power cost baseline rate has been calculated in the same manner as in the 2009 general rate case, plus the change for the LTSA major maintenance costs discussed earlier.

The proposed new power cost baseline rate is $65.257 per MWh before revenue sensitive items, compared to the current power cost baseline rate of $64.387 per MWh that was approved in the 2009 general rate case. This is shown on Exhibit No. ___(JHS-9).

Q. Would you please describe costs used to determine the new power cost baseline rate?

A. The PCA Mechanism makes a distinction between production related costs and all the other costs determined in a general rate case. In a general rate case, the Company uses a future rate year to determine certain power costs and then production adjusts those costs back to the test period. The proposed rate year used for these adjustments in this proceeding is May 2012 through April 2013. For this proceeding, PSE has used the test period ending December 2010.

In addition to providing the normal power cost restating and pro forma adjustments, PSE has provided pro forma adjustments to account for changes to its rate base and operating expenses associated with power production. These costs are included in the appropriate line items on Exhibit A-1.

Q. Please explain what Exhibit No. ___(JHS-9) presents.

A. Exhibit No. ___(JHS-9), page 1, is equivalent to Exhibit A-1 Power Cost Rate set forth in the original PCA Settlement, but has been updated to reflect the power cost changes proposed in this general rate case filing. The net of tax rate of return shown on line 7 of this first page, 7.29 percent, is the net of tax rate of return being requested by the Company in this proceeding. The test period power costs are allocated, in the same manner as in prior PCA calculations, between the PCA defined fixed and variable costs, which include the LTSA major maintenance costs discussed earlier; the total of these costs are then adjusted for revenue sensitive items. Following the same methodology set forth in Exhibit A-1 of the original PCA Mechanism filing, the Company has divided this result by the test year delivered load to calculate the new power cost baseline rate of $65.257 per MWh before revenue sensitive items.

Q. Please explain the remaining pages included in Exhibit No. ___(JHS-9).

A. The remaining pages of Exhibit No. ___(JHS-9) are equivalent to Exhibits A-2 through D set forth in the current PCA Mechanism, as updated to reflect the changes in power costs presented by the Company for this general rate case filing. In the upper left hand corner of each of these pages is the reference to the exhibit being replaced in the current PCA Mechanism.

Q. How does Exhibit A-1 impact the PCA Mechanism?

A. Exhibit A-1 is important for two reasons. First, it is the exhibit that calculates the power cost baseline rate, which is used to calculate changes in revenue deficiency in a PCORC. Second, it is the source of information used in calculating the over or under collection of power costs during a PCA period true up. Exhibit B of the PCA Mechanism uses the total of fixed costs allowed in a general rate case or PCORC filing to determine the amount of fixed costs allowed in a PCA period. These fixed costs, as presented on Exhibit A-1, do not vary without a general rate case filing or a PCORC filing. If the Company does not request that Exhibit A-1 be updated for the addition of a new resource, then the new resource's fixed costs cannot be considered as part of the true up for power costs.

Exhibit A-1 is also used on Exhibit B to provide the power cost baseline rate. This rate multiplied by the actual delivered load for a period is the amount of power costs that is included in customers' rates. The product of this calculation is compared against the sum of the fixed costs from Exhibit A-1 plus the actual allowable variable power costs during the true up period plus any adjustments of Exhibit B, to determine the over or under recovery of allowed power costs. The over or under recovery of costs is then compared to the sharing bands to determine if any deferral of power costs is needed.

VI. DEFERRED TAX RECEIVABLE TRACKER

Q. Would you please explain the Deferred Tax Receivable Tracker you mentioned earlier in your testimony?

A. Yes. As discussed earlier in my testimony, and in Mr. Marcelia's testimony, the Company had a net operating loss for both 2009 and 2010. Because the Company was not able to recover the tax benefit associated with accelerated tax depreciation from the U.S. Treasury, a tax receivable in Account 190, Accumulated Deferred Income Taxes, has been recorded. At the end of the test year the amount of this receivable was $55.2 million for electric and $44.0 million for natural gas. The average of the monthly averages balances were $23.2 million and $18.5 million for electric and natural gas respectively. As further explained by Mr. Marcelia, these receivable balances are required as an offset against the

Accumulated Deferred Tax Liability that is a credit against rate base. When the Company receives a credit from the U.S. Treasury for these tax benefits, the balances in these accounts will decrease and this will restore the full credit of the remaining deferred tax liability against rate base.

Q. When will the Company receive the credit from the Treasury for this tax receivable?

A. At the point in time when the Company has taxable income, it will be possible to carry these deductions forward to the taxable year and receive a credit against that year's taxes. Until that time, the test year tax receivables need to be included in rate base as an offset against the deferred tax liability as Mr. Marcelia discusses. In the future, any other assets pro formed into rate base, such as Lower Snake River, will also have a tax receivable associated with accelerated tax depreciation if the Company is still in a net operating loss position for tax purposes. This tax receivable must be offset against any deferred tax liability included in rates.

Q. Has the Company included the tax receivable as an offset in its Lower Snake River adjustment in this proceeding?

A. No. It is not possible to calculate the receivable at this time. Even though we expect to be in a net operating loss tax position for 2012, it is not known at this time how much of the accelerated tax depreciation will be used to offset taxable income. It is expected that there will be some taxable income that will be offset by this accelerated tax depreciation.

Q. What is the Company's proposal as to how this tax receivable will be included in rates?

A. The Company is requesting that the Commission allow the Company to remove the tax receivable recorded through 2010 from general rates and to create a tracker for both electric and natural gas that recovers this cost. For electric, this would reduce general rates by $2.729 million; and for natural gas, general rates would be reduced by $2.172 million. The trackers for electric and natural gas service would be increased by the respective amounts.

When the receivable for Lower Snake River is known the revenue impact would be filed with the Commission and the electric tax tracker would be adjusted by the appropriate amount.

Q. Would any other adjustments be made to the tax trackers?

A, No other increases other than the tax receivable discussed above would be made to the trackers prior to the next general rate case or power cost only rate case, however, decreases could occur. There would be no increases as the tracker address deferred taxes that have been included in rates as an offset against rate base. Additional accelerated tax depreciation for new plant other than Lower Snake River would not be included in rates until the plant is added to rate base and revenue recovery starts as the result of a subsequent general rate case or power cost only rate case. At that time any tax receivable associated with a net operating loss would have to be taken into consideration. Because Lower Snake River is a pro forma adjustment in this proceeding, and a deferred tax liability has been calculated and included in determining the revenue impact, a true up of the tax receivable needs to be done.

Decreases to the trackers could occur if the Company has enough taxable income in an interim year between general rate cases that the tax receivable could be utilized on the Company's return. If that were to occur then the receivable would go down and the trackers would decrease.

Q. What is the Company asking the Commission to approve?

A, The Company is requesting that the Commission approve the tax tracker as described above. With an approval of the trackers the Company will remove the impacts of the 2010 tax receivable from general rates and file electric and natural gas trackers that include the revenue impact of the tax receivable with its compliance filing for this proceeding. Exhibit No.___ (JHS-10) is suggested tariff language for such a tracker using electric as an example. Similar tariff language would be used for a natural gas tracker.

VII. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.