EXHIBIT NO. ___(JHS-1T)
DOCKET NO. UE-09___/UG-09___
2009 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-09____** **Docket No. UG-09____**

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

MAY 8, 2009

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF JOHN H. STORY

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PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF JOHN H. STORY

I. INTRODUCTION

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

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 operations for the test year used for this proceeding, plus changes to ratebase, working capital, conversion factor and the overall revenue requirement and the resultant revenue deficiency. I also provide a summary of the causes for the current revenue deficiency. I will present the updated exhibits for the Power Cost Adjustment ("PCA") Mechanism that reflect the changes to the Base Rate for the pro forma and restating adjustments to power costs. Finally, I discuss deferred accounting for the Mint Farm Generating Station ("Mint Farm") and the sale of renewable energy credits ("RECs").

Based upon the adjusted test period revenues of $2,002,420,403 for sales to customers, the total requested electric general rate case revenue deficiency is $148,443,904. Firm Resale customers are allocated $78,069 of this deficiency and Special Contract customers are allocated $217,835. Retail sales revenue deficiency is $148,148,000, which represents an average 7.40% increase. This increase does not reflect an additional production tax credit ("PTC") associated with the wind turbines being constructed at the Wild Horse Wind Project.

II. TEST YEAR FINANCIAL STATEMENTS AND RATEBASE

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

A. Exhibit No. ___(JHS-3) presents the actual electric financial statements for the test year before any pro-forma or restating adjustments. Page 3.01 of Exhibit No. ___(JHS-3) presents a comparison between the unadjusted electric income statement for 9/30/2007, the test year for Docket No. UE-072300 et al. (the "2007 general rate case" or "2007 GRC") and the unadjusted electric income statement for 12/31/2008, the test year for this general rate case filing. Page 3.02 of Exhibit No. ___(JHS-3) presents the combined end of period and average of the monthly averages (“AMA”) balance sheets for the same time periods, and page 3.03 of Exhibit No. ___(JHS-3) presents the ratebase calculation for the current test year prior to any pro forma and restating adjustments. Mr. Michael Stranik presents the equivalent schedules for natural gas operations in his Exhibit No. ___(MJS-3)

Q. Is the ratebase calculation done in the same manner as allowed in the last general rate case?

A. Yes.

Q. Would you please explain the working capital calculation?

A. This 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 by investment in plant 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 this adjustment calculates the total average invested capital that has been utilized during the test year. From the average invested capital, the electric operating investment, which is earning a return, or is excluded from earning a return, is deducted. A similar deduction is made for natural gas operating investment and the non-operating assets plus plant not in service. The result is 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 times the electric operating investment. An adjustment is made for determining the electric working capital ratio by deducting electric construction work in progress ("CWIP") from total average investments using the same methodology that has been approved in prior proceedings. The resulting operating working capital represents the investors' average investment which is required to provide utility service but which would otherwise not earn a return. The electric working capital calculation is shown in Exhibit No. ___(JHS-3), page 3.04, and adds $130,674,248 to electric ratebase.

Q. Please describe the final page 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 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, and net classified plant (excluding general plant).

Common operating costs are those costs that are incurred on behalf of both electricity and 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 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.

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 ratebase that have been proformed and restated for each of the regulatory periods, divided by the delivered load for that period. This calculation determines the major categories' unit cost for that particular period. The prior period that is used in this calculation is also adjusted for the restating and pro forma adjustments that were allowed in any interim regulatory filings between general rate cases, for example, a PCORC. There was no interim regulatory filing since the 2007 GRC, so the prior period amounts are the approved amounts from that proceeding.

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 growth and its associated revenue growth.

Exhibit No. ___(JHS-6) 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 2007 general rate case that increased electric revenues effective November 1, 2008. This exhibit shows the calculation of the difference between the unit costs between the two periods described above and the increase or decrease in cost since the last regulatory period taking into consideration revenue growth.

Based on this calculation, cost increases include the following:

(i) $13.7 million for power cost expenses related to the test period in this proceeding;

(ii) $13.7 million in customer and administrative/general expenses;

(iii) $7.8 million in transmission and distribution expenses;

(iv) Depreciation expense has increased $8.7 million:

(v) Other Operating Expense, Amortization and property losses has increased $30.1 million due to increased amortizations on 1) acquisition adjustments for Mint Farm and Whitehorn, 2) net interest due to the IRS, and 3) Mint Farm deferral; and

(vi) The change in ratebase increases the revenue requirement by $72.3 million, of which approximately $23.1 million is related to the requested change in rate of return.

Q. What are the major changes in ratebase since the last proceeding?

A. In the last general rate case filing the electric ratebase was approximately $3,303.6 million and the electric ratebase in this proceeding is at $3,771.1 million, which is an increase of $467.5 million. Transmission and Distribution plant, net of accumulated depreciation, amounts to $180.3 million of that difference. Production plant has also increased by $436.6 million, net of accumulated depreciation. These increases in ratebase are offset by the growth in deferred taxes and the increase in customer advances due to residential construction activity.

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, 2008 operating income statement and ratebase. The first page of Exhibit No. ___(JHS-4), Summary page, presents the unadjusted operating electric income statement and AMA ratebase for the Company as of December 31, 2008 (the test year) 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, and the impact on the operating income statement and ratebase is presented in the final column, which shows that the net operating income divided by the test period ratebase results in the requested rate of return. The remainder of Exhibit No. ___(JHS-4) is composed of two sections, described below.

Pages 4-A through 4-E 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-A is the unadjusted net operating income for the year ended December 31, 2008 and the unadjusted ratebase for the same period. Each column to the right of the first column represents a pro forma or restating adjustment to net operating income or ratebase. Each of these adjustments has a supporting schedule, which is referenced by the page number shown in each column title.

The second to the last column, shown on page 4-E 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 describe each adjustment, explain why it is necessary, and identify the effect on operating income or ratebase.

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.

4.01 Temperature Normalization

This adjustment, as shown in Exhibit No. ___(JHS-4), page 4.01, is restating test year delivered load and revenue to a level which 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.

Q. How was test year delivered load normalized?

A. The prefiled direct testimony of Ms. Lorin I. Molander, Exhibit No. ___(LIM-

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.

The test year was colder than normal requiring an adjustment to net operating income to bring revenues down to what would have occurred under normal conditions. The temperature load adjustment decreases actual GPI by 215,347 MWH, or 200,921 MWH when adjusted for line losses. After allocation to the different customer classes, this results in a decrease to net operating income of $12,235,767.

4.02 <u>General Revenues</u>

This is a pro forma and restating adjustment, shown in Exhibit No. ___(JHS-4), page 4.02, which adjusts the test year revenues to the revenues that would have been collected during the test year if the tariffs from the 2007 general rate case had been in effect during the entire test period. These adjusted test year revenues are included in line 3. The revenues from PSE's 2007 power cost only rate case ("PCORC ") Docket No. UE-070628 during the test period are removed as this tariff was set to zero and the revenues are now collected as part of the 2007 general rate case and are included in the adjustment on line 4.

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 4.04.

Pole attachment revenues are trued up for rate changes and contract changes during the test period on line 24, which increases revenues by $438,314. Other adjustments to revenues (on lines 6, 7, 12 and 19) relate to reclassifications and miscellaneous out-of-period price changes for all sales customers.

Delivered load in the test period has been adjusted for the load reduction associated with the conservation phase-in adjustment Mr. Jon A. Piliaris discusses in his prefiled direct testimony, Exhibit No. ___(JAP-1T). This adjustment removes 119,213,053 kilowatt hours ("kWh") from the test year and results in a reduction to revenues of $10,048,562, which is shown on line 13. This adjustment also impacts the production factor calculation which I will discuss later in my testimony.

Net operating income is increased by $80,396,404 as a result of these adjustments.

4.03 <u>Power Costs</u>

This schedule, shown on Exhibit No. ___(JHS-4), page 4.03, adjusts the test year to reflect the power costs that are projected to be incurred during the rate year. The calculation of rate year projected power cost is explained in Mr. David E. Mills' prefiled direct testimony, Exhibit No. ___(DEM-1CT), and the impact of the power cost changes between the 2007 general rate case and the rate year in the current proceeding are shown in Exhibit No. ___(DEM-7) and in more detail in Exhibit No. ___(DEM-8C). The hedging costs associated with the line of credit for electric hedging are also shown on this adjustment and add $297,532 to power costs. The line of credit costs represent the electric services portion of the fees associated with having the line of credit.

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

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

A. Yes. Historically, PSE has calculated rate year maintenance costs based upon actual test year costs plus the normalized rate year major maintenance costs. Normalized major maintenance costs for PSE's owned Frederickson 1, Goldendale and Sumas facilities reflected major maintenance contracts (Long-Term Service Agreements or Contract Service Agreements) over the contract's remaining life. Cost recoveries calculated up to the rate year were netted against these costs. The net costs were then divided by the expected run times for the machines over the contract life and the resulting hourly rate was applied to the rate year generation. Normalized major maintenance for PSE's own simple-cycle gas and oil-fired combustion turbines ("SCCTs") represented an average annual cost of the expected major maintenance over a ten year forecast period. This method recognized that major maintenance on these SCCTs, which are used to meet peak load demand, was based upon time rather than generation. For financial accounting purposes this calculation is defined as an accrue-in advance method.

Q. Is this how the Company has calculated major maintenance expense costs for the different turbines in this proceeding?

A. No. The Company is proposing to follow financial accounting guidelines for cost recovery of major maintenance. As explained above, the practice that the Company had been following for rate recovery is equivalent to an accrue-in-advance methodology, which is not allowed for financial reporting purposes. FASB Staff Position AUG AIR-1 ("the guidance") lists the following acceptable accounting methods for accounting for planned major maintenance on turbines; the direct expense method, the built-in overhaul method and the deferral method. The guidance specifically prohibits the use of the accrue-in-advance method for financial purposes.

The definitions for the acceptable accounting methods listed above are as follows:

Direct Expense Method: Costs are expensed as incurred since they are relatively constant from period to period.

Built-in Overhaul Method: Costs are segregated based on those that should be depreciated over the useful life and those that require overhaul at periodic intervals.

Deferral Method: Actual cost of each overhaul is capitalized and amortized to the next overhaul.

Turbine maintenance costs have been broken down into three categories. The first category contains costs associated with maintenance events which are less than $2 million in cost per occurrence. As these costs are fairly constant from year to year it is proposed that these costs will be handled under the Direct Expense Method. Please see the prefiled direct testimony of Mr. Louis E. Odom, Exhibit No. ___(LEO-1CT), page 25 for further discussion of this first category of turbine maintenance costs. The second category contains costs that will be prepaid under maintenance contracts but will be capitalized when the work is done. This category contains all prepaid capital costs, regardless of the amount spent on each capital event. The third category contains expenses for maintenance events over $2 million that are not capital in nature and would be expensed to production O&M. As this level of expenditure is not constant, the Company proposes to use the Deferral Method for major maintenance. For expenses in this third category, when the actual work is completed it is proposed that the expenses for these events be deferred to Account 186, Deferred Debits. The Company will then include these costs in its next electric rate proceeding that adjusts power costs. An explanation of the work that was done and a detail of the costs deferred will be provided for Commission acceptance. When the costs are accepted, it is proposed that these costs would be amortized over five years to other operating expense and the unamortized balance sheet amount would be included in ratebase as a power cost regulatory asset. Both the amortization to production O&M and the return on the regulatory asset included in production ratebase would be included in the PCA mechanism. At this time there are no deferred costs associated with major maintenance that would be included in this filing.

As discussed by Mr. Odom in his prefiled direct testimony, Exhibit No. ___(LEO-1T), the Company has reviewed its expected maintenance cost for all of the natural gas turbines and has used an annual average of the forecasted five year cost analysis to determine normalized maintenance costs, or direct expense costs for the rate year. The workpaper supporting the maintenance costs has been provided in the power cost workpapers in support of Mr. Mills' prefiled direct testimony, Exhibit No. ___(DEM-1CT).

As the Company had been collecting for some of these costs in current rates, a liability is being proformed into this case to return to the customers the amounts collected for major turbine maintenance that were not used. I discuss this adjustment later in my testimony.

Q. What is the total change to net operating income for all the power cost changes?

A. Net operating income is increased by $34,358,642 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-7), and discussed later in my testimony, adjusts the power 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 Baseline Rate is consistent with the Company's 2007 general rate case compliance filing. Exhibit No. ___(JHS-7) 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:

4.04 <u>Federal Income Taxes</u>

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 4.02 discussed earlier. The impact of this restating adjustment, shown on Exhibit No. ___(JHS-4), page 4.04, is to decrease net operating income by $20,234,048.

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

This pro forma adjustment, shown on Exhibit No. ___(JHS-4), page 4.05, uses a ratebase method for calculating the tax benefit of pro forma interest. The effect of this adjustment is to decrease net operating income by $714,135. The Company proposes a change to the calculation by removing CWIP from the calculation. Please refer to the prefiled direct testimony of Mr. Marcelia, Exhibit No. ___(MRM-1T), for a more in depth discussion of this adjustment and this change in methodology. A workpaper has been provided to all parties that shows the prior method of calculating this adjustment.

4.06 <u>Hopkins Ridge Wind Infill Project</u>

Q. What is the Hopkins Ridge Wind Infill Project?

A. The Hopkins Ridge Wind Infill Project is a 7.2 megawatt ("MW") expansion of the existing 149.4 MW Hopkins Ridge Wind Project located in Dayton, WA. The infill project installed an additional four 1.8 MW Vestas V80 turbines. This adjustment was included in the Company's last general rate case; however, as the project came on-line during the current test year, this adjustment is required to proform in a full year of the in-service capital costs associated with having this addition in ratebase plus a full year of the project's associated operating and maintenance expense.

Q. Please explain how the ratebase addition associated with this project was calculated for rate purposes.

A. The capital costs, less the accumulated depreciation and deferred taxes, projected through the March 2011 time period is the amount that PSE used to calculate the capital investment for the Hopkins Ridge Wind Infill Project. The elements of this calculation are described below.

Construction was completed in August 2008. Using the capital investment closed to plant, the average of the monthly averages plant balance was calculated for the rate period.

To calculate the depreciation expense, the depreciation rate of 4.24%, was used, which is the depreciation rate approved in the Company's 2007 general rate case. The depreciation expense was accrued monthly, and the resulting monthly-accumulated depreciation was then averaged in the same manner as the plant cost.

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), and this is the same calculation approved in prior rate case proceedings for pro forma adjustments to future plant balances.

For the Hopkins Ridge Wind Infill Project, the deferred tax calculation is based on five-year tax depreciation. The Hopkins Ridge Wind Infill Project was added to plant in the third quarter of 2008, so the mid quarter convention was used in calculating the tax depreciation and the deferred tax benefit for the first year of operation.

Depreciation expense shown on line 9 of this adjustment is described above, and the property insurance and property taxes are the estimated rate year costs for this new plant addition.

This pro forma adjustment increases ratebase by $4,704,806 and decrease net operating income by $214,972.

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

A. The next adjustment is:

4.07 <u>Wild Horse Expansion Project</u>

This restating adjustment presents the ratebase and operating expenses associated with the Wild Horse Expansion Project. The Wild Horse Expansion Project is a 44 MW expansion of the existing 228.6 MW Wild Horse Wind Generating Facility located in Kittitas County, WA. The expansion project will install an additional 22 Vestas V80, 2.0 MW, wind turbines. The plant balance of $102,551,661, shown on line 3 of this adjustment, is the adjusted rate year plant cost for the project. This project is expected to be completed in December 2009, and the extra wind capacity has been included in the Aurora run for the rate year.

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

A. To calculate the investment for the infill project, the estimated cost of construction through November 2009 was used. Using this capital investment, the average of the monthly averages plant balance was calculated for the rate period. To calculate the depreciation expense, the depreciation rate of 4.28% was used, which is the Wild Horse depreciation rate approved in the Company's 2007 general rate case. The depreciation expense was accrued monthly, and the resulting monthly-accumulated depreciation was then averaged in the same manner as the plant cost.

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 Wild Horse Expansion, the deferred tax calculation is based on five-year tax depreciation. The Company is not expecting to be required to incur the mid quarter convention in 2009; therefore, the half year convention was used in calculating the tax depreciation plus the deferred tax liability for the first year of operation.

The total of all the adjustments described above increases ratebase by $86,230,945.

Q. Please explain the other costs associated with the Wild Horse Expansion Project on Exhibit No. ___(JHS-4) at page 4.07.

A. The calculation of depreciation expense shown on line 9 is explained above. The wheeling and production costs associated with the Wild Horse Expansion Project have been moved from the power cost adjustment on page 4.03 so that the total cost of the project is shown on this adjustment. These costs are supported by the prefiled direct testimony of Mr. Mills, Exhibit No. ___(DEM-1CT) and his supporting exhibits and workpapers for rate year power costs. Property taxes and insurance are estimates for the rate year costs based on the costs for the plant.

The impact of these adjustments is to decrease net operating income by $4,434,431.

Q. Would you please explain the production tax credit?

A. The production tax credit is a subsidy provided by the U.S. Government for generating electricity from wind. The amount of the subsidy is currently 2.1 cents per kilowatt hour for wind generation and may be adjusted over time due to inflation. As of the date of this filing, this subsidy can be claimed for the first ten years for a new wind project put into service prior to December 31, 2012. The use of the credit is restricted in that it can only be used to reduce the Company's current taxes payable to either (a) 75% of the Company's tax payable before considering the credit or (b) the level of alternative minimum tax, whichever causes the higher tax liability. However, unused credits can be carried forward for up to twenty years.

Q. Do either the Hopkins Ridge Wind Infill Project or the Wild Horse Expansion Project adjustments include the PTCs associated with their

generation?

A. No. PTCs are passed through to customers on a separate tracker that is adjusted and filed in October of each year. This PTC tracker is forward-looking in that it includes the estimated PTCs that will be generated in the next year and is then trued up to what was actually generated in subsequent filings. The impacts of the Hopkins Ridge Expansion project were included in the 2008 PTC filing.

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

A. The next adjustment is:

4.08 <u>Mint Farm Energy Center</u>

The Mint Farm Energy Center is a modern, 311-MW (260 MW "nominal", plus 37 MW duct firing, plus 14 MW through steam augmentation) rated capacity natural gas-fired combined cycle combustion turbine plant. The generating facility is situated on approximately 11.42 acres of land located within the Mint Farm Industrial Park in Longview, Washington. The Mint Farm Energy Center was purchased December 5, 2008, as discussed by Mr. Roger Garratt in his prefiled direct testimony, Exhibit No. ___(RG-1HCT). On November 25, 2008 the Company informed the Commission that it would defer the costs associated with Mint Farm in accordance with RCW 80.80.060(5) and the proposed WAC 480-100-405 through 480-100-435 if the Commission determined Mint Farm was baseload plant that met the greenhouse gases emissions performance standards in RCW 80.80, or under an accounting petition if the Commission determined the plant was not a baseload plant subject to RCW 80.80. I discuss this deferral later under Adjustment 4.34.

This pro forma and restating adjustment includes the estimated cost of the Mint Farm Energy Center as of the rate year, April 2010 through March 2011, taking into consideration the original purchase price, and subsequent additions to bring the plant up to PSE's operating standard. *See* Exhibit No. ___(RG-1HCT).

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

A. The estimated acquisition price less the accumulated depreciation and deferred taxes through the March 2011 time period is the amount that PSE used to calculate the investment for the Mint Farm Energy Center. The elements of this calculation are described below.

For the rate year costs, PSE assumed that the capital costs were equal to plant costs as of January 2009 plus estimated capital additions through December 2009. The estimated capital additions are capital investments being made to Mint Farm to bring it up to Company operating standards. As there is an acquisition adjustment associated with this plant, the total acquisition cost is allocated between the plant balance and acquisition adjustment. The plant balance is equal to the original cost on the seller's books of $96,344,346 and the additional amount of $168,793 that was paid to purchase the property, which results in the $96,513,139 shown on line 3 of the adjustment. The total acquisition adjustment for additional amounts paid to purchase the property plus the subsequent upgrades to the property equals $161,337,964 and is presented on line 5. Using these amounts, the Company calculated the average of the monthly average ratebase for the rate period. The Company also calculated the accumulated depreciation and amortization by depreciating and amortizing the plant cost through March 2011 using a depreciation rate of 2.79871% on the original cost and an amortization rate of 2.94118% on the acquisition adjustment. These rates assume a 35 year service life, which is based on similar Company owned plants' depreciable lives as approved in the depreciation study accepted in the 2007 general rate case. The depreciation rates are developed by determining the amount of annual depreciation expense necessary to recover the net book value over the average remaining service life. This necessary annual depreciation expense is then converted into a rate that can be applied to the gross balance. Because the plant in service had accumulated depreciation at inception and the acquisition adjustment did not, this has resulted in the different rates for the plant versus the acquisition adjustment noted above. The deferred tax balance was also calculated through the rate year using the IRS Internal Revenue Code Regulations, Section 1.167(l)-1(h). The deferred tax calculation is based on twenty-year tax depreciation.

The resulting monthly accumulated depreciation, amortization and deferred taxes were then averaged for the rate year in the same manner as the plant cost. These adjustments increase ratebase by $223,509,079.

Q. Please describe the operating expense adjustments.

A. Rate year depreciation expense was described above. Property taxes and insurance premiums are based on estimated costs for the rate year based on the plant costs. The operating and fuel costs for Mint Farm have been moved from the Power Cost Adjustment, page 4.03, so that the total cost of the project is shown on this adjustment. These costs are supported by the prefiled direct testimony of Mr. Mills, Exhibit No. ___(DEM-1CT), and corresponding exhibits and workpapers thereto.

The impact of the operating expenses presented on this adjustment is to decrease net operating income by $54,228,064.

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

A. The next adjustment is:

4.09 <u>Sumas Cogeneration Station</u>

The Sumas Cogeneration Station is a 125 MW natural gas-fired combined cycle generating facility located on an approximately 6-acre site within the City of Sumas, Washington. This plant was in-service as of July 25, 2008 and was approved for recovery in rates in the Company's 2007 general rate case.

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

A. The acquisition price as of July 2008 less the projected accumulated depreciation and deferred taxes through the March 2011 time period is the amount that is being used to calculate the investment for the Sumas Cogeneration Station. The total ratebase addition includes the purchase price, capitalized transaction costs, due diligence and permits and capitalized property taxes that will be paid in 2009 but are related to the months in 2008 prior to the purchase. As this plant had previously been devoted to public use, there is also a negative acquisition adjustment associated with the accounting entries described above. In addition to these costs there are costs associated with capital improvements, such as computer equipment, plant security and facility improvements.

For determining the impact on ratebase, the Company used the total of the above costs as booked through February 2009 and depreciated these costs out through the rate year. PSE calculated the accumulated depreciation by depreciating this plant through March 2011 using a depreciation rate of 1.74%. This rate is based on a retirement date of July 2023, the date used by Property Accounting as the retirement date for this plant and is the same depreciation rate that was accepted in the 2007 general rate case.

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 Sumas Cogeneration Station, the deferred tax calculation is based on a combined cycle generating plant twenty-year tax depreciation.

The resulting plant investment, monthly-accumulated depreciation and deferred taxes were then averaged for the rate year. These pro forma adjustments increase ratebase by $7,282,195.

Q. Please describe the operating expense adjustments.

A. Depreciation expense is described above. Property insurance premiums and property taxes are estimates for the rate year. Operating expenses and fuel costs for the Sumas Cogeneration Station are included in the Power Cost Adjustment, approximately $20 million, and are supported by the prefiled direct testimony of Mr. Mills, Exhibit No. ___(DEM-1CT), and his supporting exhibits.

The impact of the operating expenses presented on this pro forma adjustment is to decrease net operating income by $738,416.

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

A. The next adjustment is:

4.10 <u>Whitehorn Generating Station</u>

This adjustment proforms in a full year of costs associated with the Whitehorn

Generating Station that was included in the Company’s 2007 general rate case. In February 2009, PSE acquired two GE MS7001E peaking units with a rated capacity of 75 MW each. Both of these units were previously leased and are part of the Whitehorn Generating Station. The units were installed in the early 1980’s and were originally acquired through a financing lease with Public Service Resources Corporation (“PSRC”). The facility is located in the northwest corner of Whatcom County, two miles from Birch Bay and adjacent to the BP Cherry Point Refinery.

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

A. The acquisition price less the accumulated depreciation and deferred taxes from the purchase date, February 2, 2009, through the March 2011 time period is the amount that PSE has used to calculate the investment for the Whitehorn Generating Station. As this plant had previously been devoted to public use there is a positive acquisition adjustment associated with the accounting entries recording this purchase. Accordingly, the total ratebase addition includes the seller’s original gross plant and accumulated depreciation as well as the purchase price and resulting acquisition adjustment.

For determining the impact on ratebase, PSE used the total of the above costs as being booked in February 2009 and depreciated these costs through the end of the rate year. PSE calculated the accumulated depreciation by depreciating this plant using a depreciation rate of 2.85%, which is based on a retirement date of July

2016, the date used by Property Accounting as the retirement date for this plant. For the amortization of the acquisition adjustment, the Company used a 13.48% rate, which is also based on recovering the costs by July 2016. Both of these rates were approved in the 2007 general rate case.

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 Whitehorn Generating Station, the deferred tax calculation is based on a fifteen year tax depreciation rate.

The resulting plant investment, monthly-accumulated depreciation and deferred taxes were then averaged for the rate year. These adjustments increase ratebase by $18,323,366.

Q. Please describe the operating expense adjustments.

A. Depreciation and amortization expense are described above. Property insurance premiums and property taxes are estimated for the rate year. Rate year operating expenses and fuel costs for Whitehorn of approximately $1.5 million are included in the Power Cost Adjustment page 4.03 and are supported by the prefiled direct testimony of Mr. Mills, Exhibit No. ___(DEM-1CT), and corresponding exhibits and workpapers thereto. The lease expense during the test year for this facility is also removed in Mr. Mills' adjustments for power cost.

The impact of the operating expenses presented on this pro forma adjustment is to decrease net operating income by $2,015,304.

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

A. The next adjustment is:

4.11 <u>Baker Hydroelectric Project Relicensing</u>

FERC issued a 50 year license for this facility in October 2008. This pro forma adjustment annualizes the FERC licensing costs associated with the Baker Hydroelectric Project relicensing that were included in the 2007 general rate case and adjusts the test year costs associated with the project to rate year levels.

For calculating the impact on ratebase, the actual balance in ratebase as of February 2009 was used. Using that balance, PSE calculated the amortization to the beginning of the rate year using the amortization rate of 2.22%, which was approved in the 2007 general rate case. An amortization rate of 2.00% based on the fifty-year federal permit term was used to calculate the amortization expense for the rate year. Accumulated amortization was determined by taking the average of the monthly averages of the accumulated amortization calculated through the rate year. Additional operating expenses associated with the project are discussed in the prefiled direct testimony of Mr. Mills, Exhibit No. ___(DEM-1CT), and corresponding exhibits and workpapers thereto.

This adjustment increases ratebase by $32,876,741 and decreases net operating income by $1,000,689.

4.12 Pass Through Revenues and Expenses

This is a restating adjustment which 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, the low income program, the residential exchange benefits provided by the Bonneville Power Administration, and green power. The associated expense that is recorded in the test year for these direct pass through tariffs are also removed in this adjustment. The portion of the green power program recorded in power costs has been removed in the power costs page 4.03. Additionally, the revenues associated with the PTC are removed in the Revenue and Expense adjustment, page 4.02 and the associated expense is removed in the FIT adjustment, page 4.04, as discussed above.

The net impact of this adjustment is to lower net income by $640,213.

4.13 Bad Debts

This restating adjustment calculates the appropriate bad debt rate by using the average bad debt percentage for three of the last five years of history after removing the high and low years. This is the same method approved by the Commission in PSE's 2004 and subsequent general rate case filings.

Each of the five years' bad debt expense rates are calculated on a twelve month period ending December 31 so that they are consistent with the test year in this case. The bad debt percentage for a given year is calculated by taking the actual write-offs for that year and dividing that by the net revenues for the twelve months ended August 31, 2008. The August twelve month revenues are used in this calculation as it normally takes four months after revenue is recognized to record the bad debt write-off. Using this relationship between August income and December write-offs makes sure the appropriate percentage for write-offs associated with revenues is being calculated.

The net test year revenues on line 7 is then multiplied by the three year average bad debt percentage, line 9, to determine the amount of bad debt expense. This amount is compared to the actual test year level of bad debt expense on line 12 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 is an increase to net operating income of $1,021,353.

4.14 <u>Miscellaneous Operating Expense and Ratebase</u>

This restating and pro forma adjustment, adjusts the test year for several different items.

(a) Adjustments to Operating Revenue

Restating and pro forma adjustment 4.14 adjusts the test year for the following operating revenue items.

1. Amortization of Summit Buyout Purchase Option – This pro forma adjustment is made to reflect the deferred accounting treatment for a corporate office lease modification that was approved in Docket No. UE-071876. The lease was modified by terminating and removing a purchase option and by extending the existing lease terms in consideration of a $20 million payment to the Company by Summit REIT, Inc. The proceeds net of transaction costs were approximately $18.9 million. In the 2007 general rate case, the Company was allowed to amortize the total deferred balance evenly over the remaining life of the building lease, which at the time was 12 years. This adjustment is offset by the adjustment shown on line 18 for contractual rent increases for the corporate headquarters. This adjustment increases the test year operating revenues for the amortization of the lease termination by $848,137.

(b) Adjustments to Operating Expense

2. Amortization of Deferred Taxes on Indirect Overheads Regulatory Asset (WUTC Docket No. UE-051527) – In prior years the Company had taken a deduction for certain general overhead costs associated with

construction, which created a deferred tax balance. The IRS then changed the method of deduction for these costs and required any utility that had previously deducted these items to reverse the deductions over the 2005 and 2006 tax years. In Docket No. UE-051527, the Company was authorized to set up a regulatory asset account to track the carrying costs associated with the tax payments based on the turn-around of the deductions associated with these overheads. Because the balance in the regulatory asset will be fully amortized by the rate year, this restating adjustment removes $2,048,627 of amortization of the regulatory asset from the test year.

3. <u>Amortization of Interest associated with Deferral of Unrecovered Residential Exchange Benefits Credited to Customers (WUTC Docket No. UE-071024)</u> – The United States Court of Appeals for the Ninth Circuit (the "Ninth Circuit") on May 3, 2007, in *Golden Northwest Aluminum v. Bonneville Power Administration*, No. 03-73426 ("*Golden Northwest*"), and *Portland General Electric Company v. Bonneville Power Administration*, No. 01-70003 *("PGE")*, concluded that certain Bonneville Power Administration ("BPA") actions in entering residential exchange settlements with the region's investor-owned utilities were not in accordance with law. On May 21, 2007, BPA notified the region's investor-owned utilities that it would immediately suspend payments under the challenged BPA agreements pending final decisions by the

Ninth Circuit in the outstanding Ninth Circuit challenges. On May 24, 2007, PSE filed a petition seeking an accounting order requesting deferred accounting treatment for residential and farm energy exchange benefit amounts credited to customers under Schedule 194 – Residential and Farm Energy Exchange Benefits that have not been reimbursed by BPA. Due to timing differences between pass-through of Schedule 194 credits and receipt of payments from BPA and because of suspension of such payments from BPA, PSE credited to customers approximately $32 million more as of May 31, 2007, which was paid by BPA in April 2008. In the 2007 general rate case, the remaining deferred carrying charges were approved for amortization over two years.

This pro forma adjustment, which increases expense by $237,009, amortizes the estimated deferral balance of the carrying costs as of March 2010 over two years.

4. Cost of Wire Zone Vegetation Management Program – As was discussed in the 2007 general rate case, the Company will experience incremental costs associated with new North American Electric Reliability Corporation ("NERC") standards for creating a predictable and low-growing environment of vegetation under and adjacent to rights-of-way under transmission lines rated 200kV and above. This pro forma adjustment brings the test year costs to the $2.3 million average annual

amount that was allowed for this program in the 2007 general rate case

5. <u>Increase in Service Contract Baseline Charges</u> – Similar to an adjustment made in the 2007 general rate case, baseline charges on service contracts are expected to increase. This pro forma adjustment, which increases transmission expense by $23,515 and distribution expense by $874,539, represents the expected percentage increase over test year costs. These amounts may be trued-up for changes to contract price increases during the course of these proceedings as warranted.

6. <u>Company Store</u> – Costs associated with the Company store were moved below the line in the Company's 2007 general rate case. This restating adjustment increases operating expense by $2,376 to remove some test year revenue amounts that should have been booked below the line.

7. <u>Summit Building Fourth Floor Contractual Rent Increase</u> – PSE has entered into a lease agreement for additional space in the Summit Building. This additional space is incremental and has been entered into in order to alleviate overcrowding of existing space. This restating and pro forma adjustment, shown on line 17, increases operating expense by $312,584 to adjust the test year rent for the additional fourth floor space by the contractual annual rent increases between August 2008 and March 2011.

8. Summit Building Contractual Rent Increases –This pro forma and restating adjustment shown on line 18 adjusts the test year rent expense for the Company's headquarters by the contractual annual rent increases between August 2008 and March 2011. This increase to lease expense is offset by the adjustment shown on line 3. This adjustment increases operating expenses by $629,936. The net impact before taxes for adjustments 1 and 8 is an increase to operating revenue of $218,201.

9. PSE has removed the costs for the dedicated parking spaces at the SeaTac airport and area hotels as well as the costs of athletic events that were charged above the line. This restating adjustment reduces operating expense by $26,643.

The total impact of all of the above adjustments is to increase net operating income by $994,791.

4.15 Property Taxes

This pro forma adjustment reflects the estimated property tax levy rates to be paid in 2009 based upon 2008 values. This adjustment is done in the same manner as in prior general rate cases. The levy rates are the estimated values for 2009 and will be adjusted to actual during the course of this proceeding.

The effect of this adjustment is to decrease net operating income by $1,603,694.

4.16 Excise Tax and Filing Fee

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.

The effect of this adjustment is to increase net operating income by $264,096.

4.17 Director and Officer Insurance

This restating adjustment removes the portion of Directors and Officers insurance that should be allocated to Company subsidiaries. This adjustment also reflects the current premium for the Directors and Officers insurance as it relates to the Company Directors after the merger. The cost of a carry over insurance policy for the Directors prior to the merger has been charged to Puget Energy and is not included in this proceeding. The amount of insurance included in operating expense is adjusted for the estimated increase in premiums for the most recent policy period. This adjusted amount is then further adjusted by dividing non-utility assets by total PSE assets and applying that percentage to the insurance cost to remove this portion of the insurance cost from operating expense. This remaining insurance expense is then compared to what was actually booked during the test year.

The effect of this adjustment is to increase net operating income by $205,413.

4.18 Montana Electric Energy Tax

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 as reflected in the power cost adjustment.

The effect of this adjustment is to increase net operating income by $92,531.

4.19 Interest on Customer Deposits

This pro forma adjustment to operating income is the expense impact associated with using customer deposits as a reduction to ratebase. This pro forma adjustment adds to operating expense the cost of interest for this item based on the most currently implemented interest rate which is 0.42%. Pursuant to WAC 480-100-113(9), the interest rate paid on customer deposits is determined annually based on the interest rate for a one year Treasury Constant Maturity as of the fifteenth day of January of that year. This presentation is consistent with decisions in prior general rate cases, and reduces net operating income by $61,479.

4.20 SFAS 133

This restating adjustment removes the effect of SFAS 133, which represents mark to market gains or losses recognized for derivative transactions. This accounting pronouncement is not considered for rate making purposes.

The effect of this adjustment is to increase net operating income by $4,899,699.

4.21 Rate Case Expenses

Consistent with prior rate cases, the Company has used the history of expense levels for PCORC 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 PCORC cases as another calculation.

The average cost for a general rate case using this methodology is $2.279 million. This cost is allocated 50% to electric and 50% to natural gas, which results in a $1.139 million dollar average cost for each energy group. The average cost for a PCORC case is $329 thousand.

These average costs are then normalized for recovery over two years and are then compared to the amount the Company had actually recorded in the test year for rate case expense, and the result increases net operating income by $380,361.

4.22 Deferred Gain/Loss on Property Sales

The purpose of this restating and pro forma adjustment is to provide the customer with the net gains or losses from sales of utility real property since the last general rate case. The gains and losses are allocated to gas and electric based on the use of the property. The amount of the net gain is amortized over a three-year period, with the deferred amount being included in working capital. This adjustment is done in compliance with the settlement agreement for property sales from Docket UE-89-2688-T.

This decreases net operating income by $497,986.

4.23 Property and Liability Insurance

This pro forma adjustment reflects actual and estimated premium increases for property and liability insurance expense. These costs are allocated between electric and natural gas depending on the purpose of the insurance. This adjustment will be updated to actual premiums during the course of the proceeding.

The effect of this adjustment is to decrease net operating income by $680,687.

4.24 Pension Plan

This restating adjustment adjusts the test year to reflect cash contributions to the Company's qualified retirement fund. During 2008 the Company made a cash contribution to the pension plan of $24.5 million. In 2009 the Company made a cash contribution of $6 million and is expected to make further contributions of $12.4 million by December 2009. In previous general rate cases the Commission has used the average of four years of contributions to determine the amount that is to be included in operating expense. This adjustment includes the average of the four years ending September 2009. Amounts included for the twelve months ending September 2009 include estimates which will be trued up to actual during the course of this proceeding.

The pension contribution was allocated to O&M based on wage distributions and then allocated between electric and natural gas based on the labor benefit assessment distribution allocator from Exhibit No. ___(JHS-3), page 3.05.

This adjustment also restates the expense associated with the Supplemental Executive Retirement Plan ("SERP") to an average of the four years expense ending September 2009. Like the qualified retirement plan, the SERP uses estimated expenses through September 2009. The SERP is allocated in the same manner as the pension adjustment.

The effect of this adjustment is to decrease net operating income by $2,741,878.

4.25 <u>Wage Increase</u>

This pro forma adjustment reflects the impact of wage increases and payroll tax changes, as described in the prefiled direct testimony of Mr. Thomas M. Hunt, Exhibit No. ___(TMH-1T). For represented (union) employees, the adjustment annualizes the wage increases granted in 2009, 2010, and 2011. The percentage of wage increase for International Brotherhood of Electrical Workers ("IBEW") union employees from the test year through the rate year contractual increases are: 3.25% effective April 1, 2008; 3.25% effective April 1, 2009; 3.00% effective January 1, 2010; and the estimated increase of 3.00% effective January 1, 2011. The percentage of wage increase for United Association of Plumbers and Pipefitters ("UA") union employees from the test year through the rate year are: 3.00% effective October 1, 2008; 3.00% effective October 1, 2009; and the estimated increase of 3.00% effective October 1, 2010. The contract for IBEW runs through March 31, 2010 and the UA contract runs through September 30, 2010. Annual wage increase estimates were based on the last increase prior to the end of the contract. The percentage of wage increase for non-union employees from the test year through the rate year is 3.5% effective March 1 of each year 2008 through 2011. These increases have 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 management employees are hired at lower salary rates than the more senior employees they are replacing.

Q. Are there any changes to the wage increase calculation?

A. Officer salaries were not included as part of the overall wage increase calculation since the wages for this group of employees are being kept at 2008 levels.

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 management employees for each of the last five years as of March 1st which is the effective date of annual management salary adjustments. From this, the Company determined the average annual salary per management employee and calculated the actual percent increase for management employees for years 2005 to 2008, and compared this to the projected percent wage increase for management employees. Average salary change per management as of March 1st for the years 2005 through 2008, was 1.87%, 2.95%, 4.42% and 1.29%, respectively, or 2.73% on average. This was compared to the average wage increase allowed for management employees during those same years of 3.00%, 3.00%, 3.50% and 3.50%, respectively, or 3.41% on average. The 2.73% average change between the beginning and end of each adjustment year is 79.93% of the 3.41% average increase at the beginning of each year. This percentage is applied to the expected compound wage increase of 8.06% from the end of the test year through the rate year ending March 31, 2011, to yield a 6.44% wage adjustment for management employees after considering slippage. The total pro forma adjustment reflecting the impact of wage increases and payroll tax changes for both management (non-union) and represented (union) employees, as discussed above, decreases net operating income by $3,511,487.

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

A. The next adjustment is:

4.26 Investment Plan

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. As with the wage increase, the investment plan does not include any added expenses associated with officers' contributions. Please see the prefiled direct testimony of Mr. Hunt, Exhibit No. ___(TMH-1T) for a further discussion of the Company's decision to freeze officers' pay and not to seek recovery of officers' incentive pay expenses in this case.

Net operating income is decreased by $163,422 as the result of this adjustment.

4.27 Employee Insurance

This pro forma adjustment updates the test year insurance payments to the estimated amount for the rate year. For IBEW employees, the estimated cost is based on the average Company contribution amount of $843 per eligible employee per month for the months of November and December 2008 and $910 per eligible employee per month for the months of January through December 2009. For January 2010 through March 2011, an estimated cost of $983 per eligible employee was used. The estimate was based on a historical trend of cost increases over the past 5 years. For UA employees, the estimated cost is based on the average Company contribution amount of $842 per eligible employee per month for the months of November and December 2008 and $910 per eligible employee per month for the months of January through December 2009. For January 2010 through March 2011 the cost of $983, explained above, was used. The amounts through 2009 are the result of negotiations between PSE and the IBEW union and PSE and the UA union. The average rate applied to UA employees was also applied to salaried employees.

These costs are 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 $1,007,959.

4.28 <u>Incentive Pay</u>

This restating adjustment uses a four-year average of incentive compensation made to employees. 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.

Q. Are there any changes to the incentive pay calculation?

A. Yes, in general the calculation is similar except that officer incentive pay is excluded from the calculation in the current rate case. For this calculation, the Company has used the years 2005 through 2008 and allocated the four-year average to electric and natural gas based 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 O&M amount is then compared to actual incentive pay expenses during the test year and results in an increase in net operating income of $1,137,979.

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

A. The next adjustment is:

4.29 Merger Savings

Mr. Michael Stranik explains the merger savings in his testimony Exhibit No. ___(MJS-1T)

The effect of this restating adjustment is to remove costs that are not expected to be incurred in the rate year. This adjustment increases net operating income by $568,233.

4.30 Storm Damage

This pro forma adjustment reflects adjustment of the test year expense level of storm damage expense, $9,958,953, 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, $8,082,388, is used to determine the annual normalized expense allowed for ratemaking purposes and is consistent with prior general rate case filings.

The Company is also requesting that the Commission maintain the level of IEEE defined storm expense at $8 million for deferral purposes. This is the level of IEEE storm expense that would have to be incurred prior to the Company requesting deferral of IEEE related storm costs.

As in prior general rate cases, the second part of the Storm Damage adjustment amortizes the costs related to catastrophic storms that have been deferred. The deferred costs associated with catastrophic storms (except for the December 13, 2006 wind storm), which total $33.5 million, are amortized over four years. This is the same deferral period used by the Company in the 2007 general rate case for these types of catastrophic storm deferrals. The remaining portion of the December 13, 2006 wind storm deferral will be $68.3 million at the start of the rate year. This storm cost is being amortized over 103 months, which is the number of months remaining at the beginning of the rate year from the original amortization period of ten years that began November 1, 2008, as approved in the

Company's 2007 general rate case.

The effect of this adjustment is to decrease net operating income by $6,176,024.

4.31 Regulatory Assets

This pro forma adjustment adjusts the production related regulatory assets, net of deferred federal income taxes, to their projected rate year average of the monthly averages balances. This adjustment calculates the regulatory assets and liabilities associated with production plant based on their projected rate year balances as agreed to in the PCA Settlement from the 2001 general rate case. On line 33 of this adjustment the Tenaska regulatory asset amortization is shown separately because this part of the amortization is considered flow through for tax purposes.

In the original proceeding associated with the buy down of the Tenaska fuel prices, Docket UE-971619, the principal buy down amount of $215 million was treated as a flow through item for rate recovery. Because the IRS would only allow a straight-line amortization of the $215 million over 15 years, the customer receives the tax benefit associated with this tax amortization and not the book amortization actually recorded for the $215 million. In the Federal Income Tax Adjustment (Page 4.04), the test year amortization, $23.5 million, is removed and the tax amortization, $14.3 million, is treated as a tax deduction. In this adjustment the increase in amortization between the rate year amortization, $32.3 million, and the test year amortization, $23.5 million, is treated as non-tax deductible.

The estimated proceeds of the sale of the White River water rights are also shown on this adjustment as a credit against the White River regulatory assets. The White River assets and liabilities will be offset against each other when the sale of the rest of the White River properties has been completed, as directed by the Commission in Docket No. UE-032043. The remaining balance of the White River assets will then be allocated to rates in a future proceeding. Please see the prefiled direct testimony of Mr. Paul K. Wetherbee, Exhibit No. ___(PKW-1T), for a more in-depth discussion of White River.

Besides the White River proceeds discussed above, the new regulatory assets and liabilities since the prior general rate case are:

1. Colstrip Settlement – UE-080900 – Lines 12 and 28 – this restating adjustment removes a $10.7 million settlement payment charged to production O&M during the test year and replaces it with a regulatory asset as requested in the accounting petition filed May 22, 2008, Docket No. UE-080900. This accounting petition has not come before the Commission as of the filing date for this proceeding. In this adjustment, interest is accrued on the regulatory asset from August 2008, which is the date of the payment through the beginning of the rate year. The resulting balance is then amortized over sixty months as requested in the petition. The average of the monthly averages as of the rate year for this regulatory

asset (net of deferred FIT), which totals $7,142,281, increases ratebase. Annual amortization expense of $2,487,877 is based on the five-year amortization period requested in the accounting petition. This results in a reduction of operating expense of $7,999,283, which is included in production O&M. See the prefiled direct testimony of Mr. Michael L. Jones, Exhibit No.___(MLJ-1T) and Exhibit No.___(MLJ-4) for a more detailed discussion of the Colstrip settlement.

2. Westcoast Pipeline Capacity Payment UE-082013 – Lines 13 and 29 – this adjustment relates to a deferred credit for a $3.5 million payment from FB Energy Canada Corp. ("FB Energy") for PSE's assumption of FB Energy's contractual benefits and obligations related to additional natural gas transportation capacity on the Westcoast Energy Inc ("Westcoast") pipeline. PSE will take over the transportation capacity on November 1, 2009. The amount of the reduction to ratebase of $1,347,150 was determined by amortizing the deferred credit commencing November 1, 2009 over the life of the capacity contract of nine years and then comparing the rate year average of the monthly averages balance net of deferred federal income tax to the test year average of the monthly averages balance. Adjusting for the annual amortization benefit based on the 9 year contract period decreases operating expense by $392,150. This adjustment is made to fuel expense to offset the cost of the capacity charge as was requested in an accounting petition in Docket No. UE-082013. See

the prefiled direct testimony of Mr. R. Clay Riding, Exhibit No. ___(RCR-1CT) for a more detailed discussion of the Westcoast pipeline capacity. This adjustment is done in the same manner as requested in the accounting petition filed November 6, 2008 in Docket No. UE-082013. This accounting petition has not come before the Commission as of the filing for this proceeding.

3. Over Recovery of Major Maintenance – Lines 14 and 30 – As discussed above under Adjustment 4.03 Power Costs, PSE is proposing to recover the costs of major maintenance in a different manner than has been authorized in prior proceedings. This pro forma adjustment adds a deferred credit to ratebase for the estimated amount of over collection of major maintenance costs from July 2002 until the beginning of the rate year as calculated under the old maintenance recovery method. This amount was determined by comparing actual major maintenance expenditures to the amount set in rates for equivalent types of costs. The amount of the original deferred credit as of the beginning of the rate year is estimated to be $5.7 million and will be trued up during the course of this proceeding. The adjustment assumes return of the deferred credit through amortization to other operating expense over three years. The result of this adjustment is to decrease ratebase for the rate year average of the monthly averages balance of the deferred credit net of accumulated amortization in the amount of $4,765,665. Including the annual

amortization benefit decreases other operating expense by $1,906,266.

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

The effect of all of these adjustments is to decrease net operating income by $5,037,666 and decrease ratebase by $105,246,429.

4.32 <u>Depreciation Study</u>

This restating adjustment calculates the impact of implementing the depreciation study over the test year as approved in Docket No. UE-072300, the Company's last general rate case. The new depreciation rates went into effect November 1, 2008, and this adjustment recalculates the depreciation expense as if the rates were in effect for the entire test year. The new depreciation rates were applied against the depreciable balance from January to December 2008 and compared to the actual test year amounts to determine the adjustment for the test period.

Lines 8 through 10 and Lines 15 through 17 of this adjustment demonstrate the impact of the Statement of Financial Accounting Standard No. 143, Accounting for Asset Retirement Obligations recorded in accounts 403.1 and 411.1. Because salvage is considered in the approved depreciation rates there is no effect on net operating income for this accounting pronouncement.

Since a change in book deprecation has no effect on tax depreciation, there is no adjustment to current taxes. In addition, no corresponding change was made to deferred taxes so as to not violate normalization principles.

The impact of the depreciation expense adjustment is to increase net operating income by $9,109,591 and to increase ratebase by $4,554,795.

4.33 <u>Fredonia Power Plant</u>

Mr. Garratt discusses the history of the Fredonia plants in his prefiled direct testimony, Exhibit No. ___(RG-1HCT). As explained in the testimony of Mr. Garratt, the turbines were installed in 2001 at the Fredonia Generating Station and leased by PSE from GE Capital Commercial, Inc. On November 14, 2008 the current lessor, GE Capital Commercial Inc., submitted a letter to PSE that provided PSE with sixty days' notice of the lessor's election to terminate the lease. As further explained by Mr. Garratt, PSE has elected to purchase these turbines.

For purposes of proforming these turbines into operating expense and ratebase, the price that was used is the starting estimated seller's plant balance of $69,921,452, plus estimated closing costs of $200,000 and estimated seller's accumulated depreciation at the time of purchase of $22,674,456, for a net balance of $47,246,996. The plant was then depreciated out through the rate year using a depreciation rate of 2.30620%, which is based on the remaining thirty-five year life of this asset that was obtained from like type plant included in the depreciation study adopted in the 2007 GRC.

The 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 Fredonia, the deferred tax calculation is based on a fifteen year tax depreciation rate.

The resulting plant investment, monthly-accumulated depreciation and deferred taxes were then averaged for the rate year. These adjustments increase ratebase by $41,603,405.

Q. Please describe the operating expense adjustments.

A. Depreciation is described above. Property insurance premiums and property taxes are estimated for the rate year. Rate year operating expenses and fuel costs for Fredonia of approximately $2.3 million are included in the Power Cost Adjustment page 4.03 and are supported by the prefiled direct testimony of Mr. Mills, Exhibit No. ___(DEM-1CT), and corresponding exhibits and workpapers thereto. The lease expense during the test year for this facility is also removed in Mr. Mills' adjustments for power cost.

The impact of the operating expenses presented on this pro forma adjustment is to decrease net operating income by $1,042,927.

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

A. The next adjustment is:

4.34 <u>Amortization of Mint Farm Deferred Cost</u>

As I explained earlier in my testimony, the Company filed a request with the Commission on November 25, 2008 to determine that Mint Farm complied with the greenhouse gas emission standards under RCW 80.80. This filing became Docket No. UE-082128.

The deferred costs in this pro forma adjustment are the actual and estimated costs associated with Mint Farm from the date of purchase until the beginning of the rate period calculated using the deferral methodology proposed by the Company in the above Docket. This methodology is discussed later in my testimony.

For purposes of this adjustment, the Company has assumed that there will be no variable costs in the deferral as they will be offset by the credit for market power or the credit for over recovery of power costs in the PCA true-up. This component of the deferral will be trued up in a subsequent rate proceeding based on actual deferrals associated with the variable costs.

To determine the impact of this adjustment on operating income and ratebase, the actual deferred amounts through March 2009 and the estimated deferral of monthly fixed costs plus interest booked using the Company's net of tax rate of return was calculated through March 2010. This amount was then amortized over three years. The resulting amortization of $20,223,046 shown on line 2 of the adjustment is the impact of this calculation on operating expense before applying the production adjustment factor.

The ratebase portion of the adjustment is the average of the monthly average of the deferred costs during the rate year adjusted by the average of the monthly averages of the accumulated amortization expense described above and the deferred taxes associated with this deferral. These amounts were used to adjust the average of the monthly averages of the deferred amounts recorded in December of the test year. As a result of this adjustment, ratebase is increased $32,790,782 and operating income decreased $13,649,989, before applying the production adjustment factor.

4.35 <u>Fleet Vehicles</u>

PSE received a letter, dated November 14, 2008, from GE Capital requesting the termination of the master operating lease agreement for fleet vehicles that PSE has used since 1988. Under the terms of the lease agreement, PSE can either sell the assets to a third party or buy them for the unamortized value no later than one year from the termination date. The termination date, which is January 14, 2009, is defined as sixty days from the date of the letter. PSE has notified GE Capital that the fleet vehicles would be purchased sometime prior to the lease termination date at their unamortized value.

The ratebase for this pro forma adjustment is calculated by using the estimated unamortized value of the vehicles as of January 1, 2010. Deducted from this purchase price, plus sales tax, are the estimated accumulated depreciation and deferred taxes on an average basis through the end of the rate year. Depreciation rates for the vehicles are based on the average service lives that were approved in the Company's depreciation study in Docket No. UE-072300.

To determine operating expenses, lease payments occurring in the test year were removed and the estimated book depreciation expense as discussed above was added. The result of the adjustment is an increase in the ratebase of $7,448,028 and an increase in net operating income of $1,272,207.

4.36 <u>Net Interest due to IRS for Simple Service Cost Method ("SSCM")</u>

This pro forma adjustment is the result of the final settlement for deductions taken for capitalized overheads that were subsequently disallowed by the IRS. A settlement was reached in which net interest payments were due to the IRS. This adjustment is done in the same manner as requested in the accounting petition filed November 6, 2008 and is Docket No. UE-082012. This accounting petition has not come before the Commission as of the filing date for this proceeding. Please refer to Mr. Marcelia's prefiled direct testimony, Exhibit

No. ___(MRM-1T) for a more in depth discussion of these costs. This adjustment decreases ratebase by $1,323,561 and decreases net operating income by $1,471,578.

4.37 Production Adjustment

This pro forma adjustment decreases production related ratebase and certain production expenses by the production factor that was used for calculating power costs. This adjustment is applied to power cost 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 power costs. The production factor is based on the ratio of the test period normalized delivered load to the rate year delivered load, which is 97.259%. The complement of this amount, or 2.741%, is the production factor that is used in the adjustment itself. Delivered load in the test period has been adjusted for the load reduction associated with the conservation adjustment discussed in the prefiled direct testimony of Mr. Piliaris, Exhibit No. ___(JAP-1T). This adjustment removes 119,213,053 kWh for conservation phase in from the test year, which increases the production factor from 2.207% to 2.741%. The impact of including this conservation phase in adjustment in the production factor on operating expenses is to decrease the revenue requirement deficiency by $8.3 million. Also included in the production factor is the 200,921 MWh decrease to test year load for the weather normalization adjustment discussed in Adjustment 4.01. The application of this adjustment is consistent with how the production expenses have been calculated in prior general rate cases and PCORCs.

Net operating income is increased by $4,657,230 and ratebase is decreased by $43,893,528 as the result of this adjustment.

This adjustment is the last Company adjustment for pro forma and restating adjustments to the electric service test year.

V CALCULATION OF THE ELECTRIC REVENUE DEFICIENCY

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

Q. Would you please explain what is presented in Exhibit No. ___(JHS-5)?

A. Exhibit No. ___(JHS-5) presents the calculation of the revenue deficiency based on the pro forma and restated test period. The pages in Exhibit No. ___(JHS-5) are:

5.01 General Rate Increase

This schedule shows the test period pro forma and restated ratebase, line 1, and net operating income, line 6. Based on $3,771,145,344 invested in ratebase, an 8.56% rate of return and $230,587,485 of net operating income, the Company would have an overall revenue deficiency of $148,443,904. After allocation to wholesale and special contract customers, the deficiency attributable to retail customers is $148,148,000

5.02 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 Mr. Donald E. Gaines, Exhibit No. ___(DEG-1T). The rate of return is 8.56% and 7.38% net of tax.

5.03 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 0.621262.

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 2007 general rate case?

A. Yes, the Company's proposed new Power Cost Baseline Rate has been calculated in the same manner as in the 2007 general rate case. This is shown on Exhibit No. ___(JHS-7). The proposed new Power Cost Baseline Rate is $66.911 per MWh before revenue sensitive items, compared to the current Power Cost Baseline Rate of $62.841 per MWh that was approved in the 2007 general rate case.

Q. Would you please describe the adjustments in this case 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 proforms those costs back to the test year. The proposed rate year used for these adjustments in this proceeding is April 2010 through March 2011. For this proceeding, PSE has used the test year ending December 2008.

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 ratebase and operating expenses associated with the purchase of the new resources and purchase power agreements discussed earlier. These costs are included in the appropriate line items on Exhibit A-1.

Q. Please explain what Exhibit No. ___(JHS-7) presents.

A. Exhibit No. ___(JHS-7), 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, 7.38%, 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, and the total of these costs are then adjusted for revenue sensitive items. Following the same methodology set forth in Exhibit A-1 of the current PCA Mechanism, the Company has divided this result by the test year delivered load to calculate the new Power Cost Baseline Rate of $66.911 per MWh before revenue sensitive items.

Q. Please explain the remaining pages included in Exhibit No. ___(JHS-7).

A. The remaining pages of Exhibit No. ___(JHS-7) 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 Rate used to calculate changes in revenue requirement 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. Exhibit B, page 21 of 30, in Exhibit No. ___(JHS-8)[1] 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 as shown on lines 5 and 6. These 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 line 31 to provide the baseline power cost rate. This rate times the actual delivered load for a period is the amount of power

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[1]Exhibit No. ___(JHS-8) contains the settlement terms for the Power Cost Adjustment Mechanism. It is Exhibit A to the Settlement Stipulation in Docket Nos. UE-011570 and UG-011571, and has not been altered from its original form to reflect subsequent changes to the PCORC approved in the Company's 2007 general rate case.

costs that are 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 period plus any adjustments as illustrated on lines 21 through 24 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. MINT FARM ACCOUNTING PETITION

Q. Please provide a brief background description of the Company's request for deferral of the costs related to Mint Farm.

A. On November 25, 2008, the Company filed a petition in Docket UE-082128 seeking a determination that Mint Farm, a newly acquired gas plant, complied with the greenhouse gases emissions performance standard in RCW 80.80. In its petition, the Company notified the Commission of its intent to defer the costs of Mint Farm as provided in RCW 80.80.060(6) and WAC 480-100-435(2)(a). Alternatively, PSE asked the Commission to issue an accounting order authorizing deferral of Mint Farm costs, if the Commission determined that Mint Farm did not fall under RCW 80.80. On April 2, 2009, the Company, Commission Staff, Public Counsel, and the Industrial Customers of Northwest

Utilities entered into a settlement agreement whereby the parties agreed to the entry of an accounting order by the Commission, while all other issues raised in the petition would be considered in this general rate proceeding. The other parties to the proceeding reserved their rights to challenge the prudence and recovery of costs related to Mint Farm, the deferral methodology used, compliance with RCW 80.80, and all other issues that were raised in PSE's petition and prefiled testimony. The Commission issued a final order approving and adopting the settlement agreement on April 17, 2009.

As a result of the settlement, my testimony provides additional detail regarding the appropriateness of the Company's proposed deferral methodology.

Q. Would you please describe the deferral methodology that the Company used for recording the costs associated with Mint Farm?

A. Yes. The deferral of costs includes both the fixed and variable costs associated with Mint Farm as those costs are defined under the Company's PCA Mechanism. The fixed cost component of the deferral includes nonfuel operation and maintenance expense, depreciation, insurance, taxes and cost of capital invested in ratebase associated with Mint Farm. Until Commission approval is received, the deferred fixed costs are being booked in account 186, Miscellaneous Deferred Debits, and an offsetting credit is being booked to the appropriate FERC income statement account. Upon Commission approval of the accounting deferral associated with these costs, the costs will be booked as a regulatory asset in account 182.3, Other Regulatory Assets.

The Company started booking this deferral commencing with the plant acquisition date of December 5, 2008 and proposes to end the deferral process with the effective date of new rates going into effect at the time of a Commission's order in this rate proceeding.

Q. How has the Company determined the fixed costs to defer for Mint Farm?

A. The Company is using the PCA definition of fixed costs to determine the amount to be deferred. PSE is deferring the actual depreciation and acquisition adjustment amortization that is being recorded plus the actual non-fuel operating and maintenance costs. To determine the capital costs associated with the plant, the average investment for the December 2008 through November 2009 was calculated. The Company's net of tax rate of return was applied to this investment and then 1/12th of this amount, adjusted for income taxes, was allocated to December 2008. The amount deferred to account 186 was 26/31 of this December calculated amount to reflect the December 5, 2008 purchase date.

Q. How is the Company determining the variable power costs associated with Mint Farm?

A. As with the fixed cost component of the deferral, the Company is using the PCA definition of variable costs to determine the actual costs to be deferred for Mint Farm. PSE's PCA Mechanism definition of variable power costs includes fuel and transportation costs. However, even though the PCA treats transportation costs as a variable cost, when a resource such as Mint Farm is added to the Company's portfolio, the transportation costs are actually a fixed cost because they are required to be paid whether the plant generates power or not. This can cause the variable cost per MWh to be quite high when the plant runs at low volume.

Q. Does the PCA restrict the recovery of fixed and variable costs for new resources prior to the resource being included in rates?

A. Yes. Exhibit G limits recovery of new resources to the variable costs that do not exceed the Baseline Power Cost Rate, as determined in the Company's most recent rate case. The Baseline Power Cost Rate is the total cost of all the fixed and variable costs allowed for recovery in the most recent rate case divided by the delivered load used to set rates. Because Exhibit G does not even address fixed costs, these costs would not be considered for recovery under the PCA mechanism prior to being included in rates.

Q. Does Exhibit G prohibit the Company from deferring variable costs?

A. No, Exhibit G does not preclude the Company from petitioning the Commission to allow the deferral of variable costs associated with a new resource, nor does it prohibit the Company from accounting for and deferring for later consideration by the costs incurred in connection with the acquisition of Mint Farm as allowed under RCW 80.80.060(6).

Q. Why has the Company requested that Exhibit G under the PCA Mechanism not be applied to Mint Farm?

A. The request to suspend Exhibit G for the Mint Farm deferral is to clarify that it is all the variable costs associated with the plant that are being deferred and not just the costs after application of Exhibit G. Under the proposed deferral mechanism, there would be no variable costs in the income statement, and the total variable costs would be reviewed as part of the overall costs included in the deferral.

Q. What costs are being recovered in the Company's current rates that will not be incurred due to Mint Farm being added to PSE's portfolio?

A. There are costs for market power in current rates; however, the revenues built into rates to cover such costs will not cover the costs related to Mint Farm. When a new resource is added to the portfolio, it is front-end loaded in that the costs associated with the new plant are higher in the first years due to the amount of ratebase that is being added. In addition, the cost of operating a new gas resource can be higher than the baseline rate that is built into rates.

Q. Why does it matter that the cost of operating a new gas resource can be higher than the baseline rate?

A. In the PCA true-up, the Company can only include PCA variable costs up to the current baseline rate; any variable costs in excess of the baseline rate are ignored for PCA true-up purposes. This causes a mismatch—the actual market cost of power is reduced by the amount of power that no longer needs to be purchased, but the variable costs associated with the new gas resource are excluded if they are greater than the baseline rate.

Q. Does the Company's proposed deferral include an offset for market costs built into rates?

A. Yes. Mint Farm would have reduced the forecast market power costs built into rates if the plant had been available when setting current rates. Now that the plant is in the portfolio, actual market purchases will be lower by the amount of power being generated by Mint Farm.

PSE proposes to use the estimated cost of these foregone market purchases to replace the actual PCA defined variable costs for the actual run times of Mint

Farm. The price of the market power that will be used is the price that was included in PSE's 2007 general rate case rebuttal filing, dated July 3, 2008.

The offset would be calculated using the estimated price for purchased power costs included in current rates, multiplied by the actual generation from Mint Farm over the deferral period. This calculated amount would be reflected as a credit to the 186 deferral account and a charge to Account 555, Purchased Power. The charge to Account 555 will be included in the monthly PCA true-up calculation as a power cost.

This approach for deferring the variable costs, plus recognizing the offsetting credit for market purchases avoided, is based on just the opposite logic used when new resources are acquired and put into rates. When a new resource is put into rates the baseline rate is increased by the PCA variable costs and fixed costs (return on plant, fixed O&M, fuel, gas transportation and wheeling) for the new resource and reduced by avoided market purchases or increased market power sales. The proposed deferred accounting removes the costs from the income statement that are associated with Mint Farm and puts back the allowed estimated purchase power costs. This procedure provides the customer an offset to the deferred variable costs in the amount of the market power purchases built into current rates that will be replaced by Mint Farm during the deferral period and restates the income statement so that Mint Farm is removed from power costs.

Q. Is the Company proposing to make any other calculations that would be applied to the Mint Farm deferral?

A. Yes. PSE proposes to apply a credit to any variable costs deferred, net of the market power credit explained above, if the Company over-collects power costs under the PCA true-up mechanism. This credit provides a benefit to customers that would not otherwise be available. The Company also proposes to book interest on the deferral at the Company's net of tax rate of return.

Q. Please explain how the deferral for over-collection of power costs will be calculated.

A. In addition to the credit associated with market power, the Company also proposes that the deferral of net variable costs, explained above, be offset by any over-recovery of power costs calculated under the PCA true-up mechanism. This credit will be determined prior to the implementation of the first $20 million band for over-recovery being allocated to the Company. This credit is calculated by tracking the total over-and under-recovery of power costs from the date of acquisition until Mint Farm is included in rates, and if that balance shows an over-recovery of power costs, that amount would be credited to the 186 deferral account up to the amount of deferred net variable costs associated with Mint Farm. The offsetting charge would be recognized in a FERC 407 account. If there is still an over collection of power costs in excess of the total net deferred variable costs, this over-collection would then be subject to the normal PCA sharing bands starting with the first $20 million band for over-recovery being allocated to the Company.

Q. Would you please explain the interest accrual on the deferred amounts that is proposed by the Company?

A. Yes. PSE proposes to accrue interest on such deferred amounts in account 186 at PSE's authorized net of tax rate of return for the period, seven percent (7%), pursuant to the Partial Settlement Re: Electric and Natural Gas Revenue Requirements and Order 12 in the Company's most recent general rate case, Docket UE-072300 *et al*. This interest commences with the initial recognition of deferred costs and ends with the effective date of new rates going into effect as a result of the Commission's order in this rate proceeding. This recovery of interest cost is required because the Company has obtained the funds from debt and equity investors to cover the expenditures that have been deferred. Because the recovery of the deferred costs will be in the future, the interest deferral makes the Company whole for the cost of the funds used to buy and operate the plant prior to its being included in rates. The net of tax rate of return is used so that the customer receives the tax benefit of the interest deduction included in the rate of return.

Q. Is the Company proposing an amortization schedule for the costs that are deferred?

A. Yes. In the Company's pro forma adjustment, page 4.34, PSE proposes that such deferred amounts, plus accrued interest, should be amortized over three years, which is the time period over which deferred costs related to PSE's Goldendale plant are being amortized, or over an appropriate time to be determined in this rate proceeding.

VII. RENEWAL ENERGY CREDIT (REC) REVENUES

Q. Will the Company update the revenue deficiency for the sale of RECs to California utilities if those transactions are completed?

A. It will depend on the final disposition of an accounting petition that is currently pending with the Commission. This accounting petition is Docket No. UE-070725, which the Company filed to gain Commission approval as to the allocation of proceeds from the sale of RECs. The Company plans to update that accounting petition with a proposal as to how the proceeds from REC sales should be allocated, taking into consideration the sale of RECs in California. If the results of that filing impact the revenue deficiency requested in this proceeding, an update for that impact will be provided.

VIII. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.