EXHIBIT NO. ___(AS-1HCT)
DOCKET NO. UE-13____
2013 PSE PCORC
WITNESS: ALIZA SEELIG

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-13______**

PREFILED DIRECT TESTIMONY (HIGHLY CONFIDENTIAL) OF ALIZA SEELIG ON BEHALF OF PUGET SOUND ENERGY, INC.

REDACTED VERSION

APRIL 25, 2013

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (HIGHLY CONFIDENTIAL) OF ALIZA SEELIG

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

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

A. My name is Aliza Seelig. My business address is 10885 N.E. Fourth Street Bellevue, WA 98004. I am employed by Puget Sound Energy, Inc. ("PSE") as a Consulting Energy Resource Planning and Acquisition Analyst.

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(AS-2).

Q. What are your duties as Consulting Energy Resource Planning and Acquisition Analyst?

A. My present responsibilities include review of, and participation in, analysis of individual power resources and portfolios of power resources for PSE's resource acquisition processes. Additionally, I coordinated with the integrated resource planning, load forecasting, and portfolio hedging teams at PSE to ensure that PSE's 2011 Request for Proposals for All Generation Sources (the "2011 RFP") process and transmission renewals analyses included the most consistent, up-to-date models and assumptions available for the decision process.

Q. What is the nature of your prefiled direct testimony in this proceeding?

A. This prefiled direct testimony describes the quantitative analysis process, the quantitative models and metrics, analysis scenarios, and key input assumptions used in the 2011 RFP. The quantitative analysis plays an integral role in the acquisition process by creating a basis to determine the lowest reasonable cost resources that meet the need for resources. However, the RFP decision to acquire a resource is not based on quantitative analysis alone. PSE performs thorough due diligence while incorporating its commercial expertise to recommend the lowest cost and risk resources to meet customers' needs.

My testimony will conclude with the results of the quantitative analysis used in assessing the prudence of Bonneville Power Administration ("BPA") transmission contracts that are used to meet PSE's capacity need. Please see the prefiled direct testimony of Mr. Tom A. DeBoer, Exhibit No. ___(TAD-1T), for a discussion of the prudence analysis for PSE's BPA transmission contracts. The transmission contracts were evaluated using the same models as described for the 2011 RFP process. The input assumptions, scenarios, and model versions vary based on the vintage of the analysis.

II. OVERVIEW OF THE QUANTITATIVE ANALYSIS PROCESS

Q. Please provide an overview of PSE's process for quantitative analysis for the 2011 RFP.

A. The quantitative analysis for the 2011 RFP is a three-step process:

> Step 1: Identify capacity, energy, and renewable needs and resources.
>
> Step 2: Create optimal, integrated portfolios for each scenario.
>
> Step 3: Evaluate costs and risks.

Q. Please describe the first step, in which PSE identifies capacity, energy, and renewable needs and resources.

A. In Step 1, PSE updates the calculation of capacity, energy, and renewable need to reflect the most current PSE load forecast and resources available. PSE also screens the RFP offers in the Portfolio Screening Model I (referred to in this testimony as the "<u>Screening Model</u>", but also referred to in other materials as "<u>PSM I</u>") to help identify a candidate short list on which to conduct further due diligence.

Q. Please describe the second step, in which PSE creates optimal, integrated portfolios for each scenario.

A. In Step 2, PSE uses its Portfolio Screening Model III (referred to in this testimony as the "Optimization Model", but also referred to in other materials as "PSM III") that integrates dispatch from the AURORAxmp model (the "AURORA Dispatch Model") to create optimal, integrated portfolios for multiple scenarios. In this process, input assumptions and resource needs are reviewed to ensure that the most current data informs the decision process.

Q. Please describe the third step, in which PSE evaluates costs and risks.

A. Finally, in Step 3 PSE uses the combination of stochastic modeling, the AURORA Dispatch Model, and the Optimization Model to identify the costs and risks of portfolios.

III. QUANTITATIVE ANALYSIS MODELS

A. The AURORA Dispatch Model

Q. Please describe the AURORA Dispatch Model.

A. The AURORA Dispatch Model is a fundamentals-based production cost model that incorporates factors such as the performance characteristics of supply resources, regional demand for power, and transmission availability to estimate the market price of power used to serve PSE's customer load.

The AURORA Dispatch Model also has the capability to simulate the addition of new generation resources and the economic retirement of existing units through its long-term optimization studies. This optimization process simulates what happens in a competitive marketplace and produces a set of future resources that have the most value in the marketplace.

B. The Stochastic Model

Q. Please describe the stochastic modeling process.

A. The stochastic modeling process allows PSE to understand the risks to portfolio revenue requirement associated with individual portfolios by creating 250 Monte Carlo draws simulating the Mid-Columbia hub ("Mid-C") power prices, Sumas gas prices, PSE load, hydropower output and wind generation output. The AURORA Dispatch Model simulates PSE's portfolio dispatch, and market purchases and sales based on the 250 draws.

The simulations take into account PSE's F2012 load forecast, the 2011 RFP Phase II range of power and gas prices, and the historical variability of natural gas prices, power prices, hydro generation, and wind generation. Please see Section V, "Key Assumptions", below for a discussion of these variables.

C. PSM I – The Screening Model

Q. Please describe the Screening Model.

A. The Screening Model is a Microsoft Excel-based hourly dispatch simulation model developed by PSE to evaluate incremental cost and risk for a wide variety of resource alternatives and portfolio strategies. PSE used the Screening Model to perform the analysis during its initial resource screening (Phase I of the 2011 RFP) and as part of its final evaluation of the most promising resources (Phase II of the 2011 RFP). The Screening Model uses a simplified dispatch logic that results in a generation unit dispatching if the variable cost of operation during an hour is less than market price. This facilitates screening of a large number of resource alternatives, which can then be taken into the Optimization Model[1], where the more complex unit commitment logic will be applied, which includes factors such as heat rate curves and minimum run times, among other inputs.

Q. What does the Screening Model calculate?

A. The Screening Model calculates the incremental portfolio costs of resources required to serve load, including the following:

(i) the variable operating costs (including fuel and emissions) for PSE's existing fleet;

(ii) the fixed and variable operating costs (including fuel and emissions) for new resources;

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[1] The Optimization Model is explained in Section III.D., below.

(iii) the fixed depreciation and capital cost of investments in new resources;

(iv) the market purchases or sales in hours when resources are deficient or surplus to PSE's energy need; and

(v) end effects with replacement resources.

Q. How is the Screening Model used?

A. The Screening Model is a modeling tool that can be used to:

- evaluate and compare results quickly for a wide range of resource alternatives;
- calculate variable costs for all resources, including existing and new resources, as well as fixed costs for new resources; and
- address other topics, such as end effects for resource alternatives that have varying lives.

Q. What are the primary input assumptions to the Screening Model?

A. The primary input assumptions to the Screening Model are:

- PSE's existing portfolio;
- projected gas and power prices;
- costs of generic resources;
- financial assumptions such as cost of capital and escalation rates; and
- a generic resource mix (from the Optimization Model).

Q. Please describe in general terms how the Screening Model works.

A. The Screening Model calculates project economics for individual RFP offers compared to the cost of a "generic" resource, which allows the quantitative team to evaluate offers relative to generics and other offers. In this way, the Screening Model is an effective tool for screening proposals because it helps PSE identify the most attractive resources for further analysis.

In the model, PSE's existing and contracted resources are used to meet PSE's future needs for capacity resources while its renewable resources are used to meet its renewable portfolio standard ("RPS") obligations. When there is a deficit in one of these two categories of need, the Screening Model "builds" generic resources to fill in the gaps. Generic resources represent PSE's most up-to-date assumptions about typical resources of varying technology types. These generic resources are then used to evaluate the merits of the RFP bids. Bids that are more attractive than generic resources have a positive portfolio benefit, while those that are less attractive have a negative portfolio benefit.

Generic resources are displaced in the model with an individual project, such as an RFP project, to measure its impact on PSE's overall portfolio cost.

Q. What are the primary outputs of the Screening Model?

A. The Screening Model identifies PSE's long-term revenue requirements for the incremental generic portfolio and compares the cost of the generic portfolio to a portfolio that contains the resource being evaluated, displacing an equivalent amount of generic resource. The Screening Model calculates five metrics used by PSE to assess the economic competitiveness of individual proposals:

(i) **Portfolio Benefit ($):** Portfolio Benefit is the difference between the net present value of the portfolio revenue requirement with the proposed project in the portfolio replacing an equivalent amount of generic resource, and the net present value of the portfolio revenue requirement of the all generic portfolio. Portfolio benefits are useful for comparing projects with the same winter capacity value or the same contribution to meeting PSE's renewable energy target. Higher portfolio benefits are better.

(ii) **Levelized Cost ($/MWh):** Levelized Cost is the net present value of the proposed project's revenue requirement divided by the net present value of the proposed project's generation. Levelized costs are useful for comparing projects that have the same or similar operating characteristics. Lower levelized costs are better.

(iii) **Portfolio Benefit Ratio**: Portfolio benefit ratio is the portfolio benefit divided by the net present value of the proposed project's revenue requirement. Portfolio benefit ratios are useful for comparing projects that have the same or similar operating characteristics. Higher portfolio benefit ratios are better.

(iv) **Levelized net cost per unit of contribution to need ($/kW or $/REC):** Levelized net cost per unit of contribution to need is the difference between the net present value of the project revenue requirement and the net present value of the market revenue of the project's generation divided by the net present value of the project's capacity contribution. If PSE is considering a renewable project, then the numerator is divided by the net present value of the project's contribution to PSE's renewable energy target. Levelized net costs per unit of contribution to need are useful for comparing across technologies and size. Lower levelized net costs per unit of contribution to need are better.

(v) **Levelized portfolio benefit per unit of contribution to need ($PB/kW or $PB/REC):** Levelized portfolio benefit per unit of contribution to need is a project's portfolio benefit divided by the present value of the project's capacity contribution. If PSE is considering a renewable project, then the numerator is divided by the net present value of the project's contribution to PSE's renewable energy target. Levelized portfolio benefits per unit of contribution to need are useful for comparing across technologies and size. Higher levelized portfolio benefits per unit of contribution to need are better.

Together, the five metrics provide relative rankings for the projects PSE evaluates, and each metric provides a slightly different perspective on the economic benefits associated with each proposal.

D. PSM III – The Optimization Model

Q. Please describe the Optimization Model.

A. The Optimization Model is a Microsoft Excel-based capacity expansion model that PSE developed to evaluate incremental costs and risks of a wide variety of resource alternatives and portfolio strategies. The Optimization Model combines the economic dispatch of resources from the Aurora Dispatch Model, with PSE's revenue requirement model, a stochastic model, and a portfolio optimization model, using an Excel-based add-in Frontline Systems Risk Solver Platform. Please see pages Exhibit No. ___(RG-3) at pages 351-55 for a description of the Optimization Model.

Q. What is the output of the Optimization Model?

A. The Optimization Model identifies PSE's long-term revenue requirement for incremental portfolios under multiple scenarios and the risk of each portfolio. The Optimization Model calculates the incremental portfolio costs, including the following, of selected portfolios:

(i) the variable operating cost (including fuel and emissions) for PSE's existing fleet;

(ii) the fixed and variable operating cost (including fuel and emissions) for new resources;

(iii) the fixed depreciation and capital cost of investments in new resources;

(iv) the book cost and offsetting market benefit remaining at the end of the 20-year model horizon; and

(v) the market purchases or sales in hours when resource dispatched outputs are deficient or surplus to meet PSE's energy need.

Q. What are the primary input assumptions to the Optimization Model?

A. The primary input assumptions to the Optimization Model are:

- PSE's peak and energy demand forecasts;
- PSE's existing and generic resource capacities;
- expected dispatched energy (MWh), variable cost ($000) and revenue ($000) from the AURORA Dispatch Model for existing contracts and existing and generic resources;
- capital and fixed-cost assumptions of generic resources;

- financial assumptions such as cost of capital and escalation rates;
- capacity contributions and planning margin constraints; and
- renewable generation contributions and renewable portfolio targets.

Q. How does the Optimization Model generally work?

A. The Optimization Model produces an optimal mix of resources that minimizes the present value of revenue requirements subject to planning margin and renewable portfolio standard constraints. The Optimization Model is solved using Frontline System's Risk Solver Premium software, which provides various linear, quadratic and nonlinear programming solver engines in the Microsoft Excel environment. It also provides a simulation tool to calculate the expected costs and risk metrics for any given portfolio.

Q. What risk metrics does PSE use to evaluate risk identified in the simulations in the Optimization Model?

A. The metrics used by PSE to evaluate risk identified in the simulations in the Optimization Model are Tail Var 90, Cost at Risk, and volatility:

(i) **Tail Var 90 ("TVar90") ($):** TVar90 is a risk measure to analyze bad outcomes, calculated as the mean of the worst 10% of possible outcomes. Lower TVar90 is better.

(ii) **Cost at Risk ($):** Cost at Risk is the TVar90 less the expected cost and measures the distribution between the expected cost and the high cost outcomes. Lower Cost at Risk is better.

(iii) **Volatility (%):** Volatility is a measure of year-to-year variability in costs. Volatility is an indicator of portfolios that would result in more or less stable rates over time. Volatility is estimated as the mean standard deviation of percentage changes in year-to year costs across the 1,000 Monte Carlo simulations. Lower Volatility is better.

E. Model Updates Since the 2011 IRP

Q. Did PSE make any changes to the Screening and Optimization Models for evaluation in the 2011 RFP?

A. Yes. PSE made two key changes to the Screening and Optimization Models for evaluation in the 2011 RFP. They include a change in logic for end effects and Renewable Energy Credit ("REC") banking.

Q. What changes did PSE make with respect to the logic for end effects?

A. For the 2011 RFP, PSE updated the end effects calculations that were used in the Screening Model and the Optimization Model. Although the existing calculation was a reasonable approach to calculating end effects, PSE made two adjustments to the end effects calculation for the 2011 RFP:

(i) extend the revenue requirement calculation for the life of the plant; and

(ii) include replacement costs on an equivalent life basis for plants that retire to put all proposals on equal footing in terms of service level.

Q. Please describe PSE's changes to extend the revenue requirement calculation for the life of the plant.

A. Previously, PSE calculated end effects based on a combination of the book value and operating cash flow. The operating cash flow (market value) is the market revenue from the output of the plant less operating expenses and current taxes for the remaining book life of the plant. If the operating cash flow were positive, the end effect value would be book value less operating cash flow. If the operating cash flow were negative, the end effect value would be the book value.

To reflect the ongoing costs of the plant, PSE extended the revenue requirement over the remaining life of the plant. PSE based the extension of the revenue requirement for end effects on the operational characteristics of the twentieth year in the AURORA Dispatch Model. The revenue requirement calculation takes into account the return on rate base, operating expenses, book depreciation and market value of the output from the plant. The operating expenses and market revenues are escalated at standard escalation rate.

Q. Please describe PSE's changes to include replacement costs on an equivalent life basis for plants that retire to put all proposals on equal footing in terms of service level.

A. Previously in the Screening Model and the Optimization Model, PSE replaced resources that retire during the first twenty years of the evaluation with generic resources in order to meet capacity and RPS constraints. When a resource was retired after this twenty-year time period, however, PSE did not replace the plant with an equivalent plant. To account for the differences in lives of projects, PSE modified the models to include a replacement cost at the end of the project life in the post twenty-year period. By adding replacement costs in this period on a levelized cost basis, the models create equivalent lives for all the resource additions.

Q. What changes did PSE make with respect to REC banking?

A. PSE implemented a REC banking methodology in the Screening and the Optimization Models to account for RECs produced in excess of compliance targets. PSE implemented REC banking for existing resources but not for "generic" or resources proposed in the 2011 RFP because the Optimization Model would not find robust solutions with the inclusion of that logic. Existing renewable resources are not subject to this same constraint because they are part of PSE's existing portfolio and are not a decision variable considered in the optimization.

Q. What assumptions did PSE make for purposes of REC banking?

A. PSE made several assumptions for purposes of REC banking in the models:

- REC production is estimated based on long-term expected generation—actual decisions to sell or bank consider REC generation variability;
- RECs produced from apprentice labor multiplier credits are not bifurcated from underlying RECs;

- non-REC eligible generation such as hydro efficiency upgrades are not banked; and
- RECs not used for compliance in the year they are created, or banked for future year's use are sold at voluntary market price.

For purposes of quantitative analysis, PSE also assumed that PSE would sell at a voluntary market price those RECs not used for compliance in the year they were produced or banked for future years' usage.

IV. SCENARIOS

Q. How did PSE test portfolio costs and risks for a variety of possible future conditions?

A. PSE developed scenarios for the 2011 RFP to test portfolio costs and risks in a wide variety of possible future conditions and isolated the effects of an individual variable. Scenarios are "pictures" of the future that reflect a set of integrated assumptions that could occur together. This enables PSE to test how portfolio costs and risks respond to changes in economic conditions, environmental legislation, natural gas prices, and energy policy. PSE developed the following five scenarios for the 2011 RFP:

- Base;
- Low Growth;
- High Prices;
- Base + CO_2; and

- Base with New Gas Price (added in late April 2012).

Q. Did PSE consider any other scenarios for the evaluation of the Ferndale Generating Station?

A. Yes. PSE also included the Draft 2013 Integrated Resource Plan ("Draft 2013 IRP") Base[2] gas and power prices in its analysis of the Ferndale Generating Station.

A. Base Case Scenario

Q. Please generally describe the Base Case scenario.

A. The Base Case scenario reflects falling natural gas prices, electricity prices, and the abandoned federal legislative efforts for an economy-wide cap-and-trade program that have occurred since completion of the 2011 IRP.

Q. What resource cost assumptions does the Base Case scenario reflect?

A. The estimated cost of generic resources for the Base Case scenario are consistent with the 2011 IRP, applying a 2.5% annual inflation rate. In general, cost assumptions represent the "all-in" cost to deliver a resource to customers, which includes plant, siting, and financing costs. PSE's activity during the past five years in the resource acquisition market and in developing resources informs its cost assumptions. Also, PSE's discussions with developers, vendors of key

[2] The draft PSE 2013 IRP refers to the PSE 2013 IRP draft presented to the IRP Advisory Group on September 6, 2012.

project components, and firms that provide engineering, procurement, and construction services lead PSE to believe the estimates are appropriate and reasonable.

Q. What heat rate assumptions does the Base Case scenario reflect for new plants?

A. Improvements on the heat rate assumptions for new plants are based on estimates by the Energy Information Administration in the Annual Energy Outlook Base Case scenario. PSE expects new equipment heat rates to improve slightly over time, as they have in the past.

Q. What regional demand growth assumptions does the Base Case scenario reflect?

A. PSE bases regional demand growth on the forecast published in the Sixth Power Plan by the Northwest Power and Conservation Council.

Q. What PSE-specific demand growth assumptions does the Base Case scenario reflect?

A. PSE-specific demand growth incorporates assumptions about regional demand growth but also includes many factors specific to the service territory. PSE relied on the F2011 load forecast for the 2011 RFP Phase I analysis and the F2012 load forecast for the 2011 RFP Phase II analysis.

Q. What natural gas price assumptions does the Base Case scenario reflect?

A. Gas price forecasts are a combination of forward marks in the near term and Wood Mackenzie forecasts for the longer term. In particular, PSE used two Base Case scenarios for natural gas prices.

(i) 2011 RFP **Phase I – Screening:** For the 2012 through 2015 period, PSE used the three-month average of forward marks for the period ending April 12, 2011. Beyond 2015, PSE used long-run, fundamentals-based gas price forecasts published by Wood Mackenzie in April 2011.

(ii) 2011 RFP **Phase II – Optimization and Risk:** For the 2012 through 2015 period, PSE used the three-month average of forward marks for the period ending November 7, 2011. Beyond 2015, PSE used long-run, fundamentals-based gas price forecasts published by Wood Mackenzie in October 2011.

Q. What production tax credits, investment tax credits, and treasury grant assumptions does the Base Case scenario reflect?

A. The Base Case scenario did not include any extensions of the production tax credits, investment tax credits, and treasury grants.

Q. What renewable portfolio standards assumptions does the Base Case scenario reflect?

A. Renewable portfolio standards currently exist in 29 states and the District of Columbia, including most of the western United States and British Columbia. The Base Case scenario assumed no changes in existing laws.

Q. What build constraint assumptions does the Base Case scenario reflect?

A. PSE added constraints and retirements on coal technologies to the AURORA Dispatch Model in order to reflect current legislation and rulemakings.

B. Low Growth Scenario

Q. Please generally describe the Low Growth scenario.

A. The Low Growth scenario models weaker long-term economic growth than the Base Case. Specifically, the Low Growth scenario models the following:

- Lower demand for energy in the region and in PSE's service territory;
- Lower natural gas prices due to lower energy demand; and
- Lower cost of energy resources because demand for power plants is depressed by lower economic growth.

C. High Prices Scenario

Q. Please generally describe the High Prices scenario.

A. The High Prices scenario models more robust long-term economic growth than the Base Case. Specifically, the High Prices scenario models the following:

- Higher demand for energy in the region; and
- Higher natural gas prices that reflect the increased demand.

D. Base + CO_2 Scenario

Q. Please generally describe the Base + CO_2 scenario.

A. The Base + CO_2 scenario tests portfolio decisions in a world with moderate CO_2 costs. Specifically, the Base + CO_2 scenario models power and gas prices that reflect higher CO_2 costs than the Base Case.

E. Base with New Gas Price Scenario

Q. Please generally describe the Base with New Gas Price scenario.

A. The Base with New Gas Price scenario is the same as the Base Case scenario but updates natural gas prices from April 2012. PSE slowed the RFP process to incorporate this lower gas price into the decision process.

V. KEY ASSUMPTIONS

Q. What key input assumptions does PSE include in the quantitative analysis?

A. The range of forecasts evaluated by PSE in the quantitative analysis reflects estimates and assumptions for the following key areas: (i) power prices; (ii) natural gas prices; (iii) demand forecasts; (iv) generic resources; and (v) CO_2 costs. Please see Exhibit No. ___(AS-3) and Exhibit No. ___(MM-3HC) at 23 for a table of the scenario assumptions.

A. Power Prices

Q. What projected power prices did PSE use in conducting quantitative analyses for the 2011 RFP?

A. PSE developed projected power prices for each of the five scenarios discussed above. Please see Exhibit No. ___(AS-4) and Exhibit No. ___(MM-3HC) at 98 and 99 for the power prices used by PSE for each of the scenarios.

Q. Were the projected power prices used by PSE in the 2011 RFP higher or lower than the projected power prices used by PSE in the 2011 IRP?

A. The projected power prices used by PSE in the 2011 RFP were lower than the projected power prices used by PSE in the 2011 IRP. Please see Exhibit No. ___(AS-5) and Exhibit No. ___(MM-3HC) at 100 for a comparison of the 2011 RFP levelized power prices to the 2011 IRP levelized power prices. PSE based the 2011 IRP projected power prices on the October 2010 release of gas prices, and the general trend in gas prices is declining. Due to the high correlation between power and gas prices, a downward trend of natural gas prices causes downward pressure on the power prices.

Q. Does PSE expect that power prices will remain stable?

A. No, not necessarily. Power prices tend to be volatile and are not as stable as shown in forecasts. Please see Exhibit No. ___(AS-6) and Exhibit No. ___(MM-3HC) at 101 for a comparison of historical Mid-C power prices (2000-2011) compared to the forecasts starting with the 2005 Least Cost Plan to the current 2011 RFP. PSE runs a range of scenarios along with stochastic simulations to capture the uncertainty inherent in the volatile and unpredictable nature of power prices.

The stochastic modeling process allows PSE to understand the risks to portfolio revenue requirement associated with individual portfolios by creating 250 Monte Carlo draws simulating Mid-C power price, Sumas gas price, PSE load, hydropower and wind generation. The AURORA Dispatch Model simulated PSE's portfolio dispatch, and market purchases and sales based on the 250 draws. The simulations took into account PSE's F2012 Load forecast, the 2011 RFP Phase II range of power and gas prices, and the historical variability of natural gas prices, power prices, hydro generation, and wind generation.

Please see Exhibit No. ___(AS-7) and Exhibit No. ___(MM-3HC) at 103 for the annual Mid-C power price distribution for the 2011 RFP. Please see Exhibit No. ___(AS-8) and Exhibit No. ___(MM-3HC) at 104 for a comparison of the simulated annual price distributions to historical price distributions between 2000 and 2010.

B. Natural Gas Prices

Q. What projected natural gas prices did PSE use in conducting quantitative analyses for the 2011 RFP?

A. For resource planning and acquisition analyses, PSE used a combination of a three-month average of the forward price marks for natural gas and the Wood Mackenzie Long-Term View forecasts for natural gas. The forward price marks are typically available for about five years ahead (through 2015 as of July 2010 and through 2016 in April 2012). The Wood Mackenzie Long-Term View is a twenty-year forecast. The inputs used in the forecasts are:

(i) **2011 IRP Base:** Forward marks as of July 30, 2010, and the Wood Mackenzie Long-Term View forecast published in April 2010.

(ii) **2011 RFP Phase I Base:** Forward marks as of April 12, 2011, and the Wood Mackenzie Long-Term View forecast published in April 2011.

(iii) **2011 RFP Phase II Base:** Forward marks as of November 7, 2011, and the Wood Mackenzie Long-Term View forecast published in October 2011.

(iv) **2011 RFP Phase II with New Gas:** Forward marks as of April 19, 2012, and the Wood Mackenzie Long-Term View forecast published in April 2012.

Q. Were the projected natural gas prices used by PSE in the 2011 RFP higher or lower than the projected natural gas prices used by PSE in the 2011 IRP?

A. Projected natural gas prices have declined since PSE developed the projected natural gas prices for the 2011 IRP in July 2010. For example, the levelized projected natural gas price of $8.08/MMBtu from the 2011 IRP has declined to a levelized projected natural gas price of $5.43/MMBtu from the 2011 RFP Phase II. Please see Exhibit No. ___(AS-9C) and Exhibit No. ___(MM-3HC) at 85 and 86 for the natural gas prices for the Sumas Hub used by PSE for each of the scenarios.

Q. What is generally causing the trend in declining natural gas prices?

A. In general, the declining natural gas prices are due to the continued and increasingly efficient development of shale gas resources and stagnant growth in demand. As gas producers have gained more experience in drilling and developing shale gas resources, the cost of production has declined. This is especially noticeable in the short-term prices. The relatively slow economic recovery in the U.S. and uncertainty in world-wide growth prospects have also tended to reduce prices. Specifically for Sumas, slowing demand for Western Canadian Sedimentary Basin gas in eastern markets due to penetration of Marcellus and Utica shale gas into eastern Canada and northeast U.S. markets, along with delays in Alberta Oil Sands demand, has created a relative surplus of supply in western Canada.

Additionally, over the shorter term, the relatively warm 2011-12 winter in North America reduced gas demand, which tended to reduce prices during the heating season. Consequently, the diversion of surplus gas to storage has tended to reduce prices for the summer and coming winter.

Q. Did PSE develop high and low projected natural gas price forecasts?

A. Yes. PSE developed high and low natural gas price forecasts using the base, high and low price forecasts from the 2011 IRP. Starting with the 2011 IRP forecasts, PSE calculated the respective percentage differences between the base forecast and the high and low price forecasts on a monthly basis. PSE based these monthly percentages on rolling eight-year average prices. PSE used the rolling average prices to smooth out the price effects of the proposed Alaska Gas Pipeline. PSE then multiplied these percentages by the 2011 RFP screening Base Case price forecast to get the low and the high price forecasts. Please see Exhibit No. ___(AS-10C) and Exhibit No. ___(MM-3HC) at 87 for a comparison of 2011 RFP natural gas price scenarios compared to the 2011 IRP natural gas price scenario. Please see Exhibit No. ___(AS-11HC) and Exhibit No. ___(MM-3HC) at 88 for a comparison of historical Sumas natural gas prices (2000-2011) compared to the forecasts starting with the 2005 Least Cost Plan to the current 2011 RFP.

As discussed above, the stochastic modeling process allows PSE to understand the risks to portfolio revenue requirement associated with individual portfolios by creating 250 Monte Carlo draws simulating Mid-C power price, Sumas gas price, PSE load, hydropower and wind generation.

Please see Exhibit No. ___(AS-12C) and Exhibit No. ___(MM-3HC) at 102 for the annual Sumas natural gas price distribution for the 2011 RFP. Please see

Exhibit No. ___(AS-13) and Exhibit No. ___(MM-3HC) at 103 for a comparison of the Sumas simulated monthly price distributions to historical price distributions between 2000 and 2010.

C. Demand Forecasts

Q. Please describe the demand forecast that PSE developed for the 2011 RFP.

A. The demand forecast PSE developed for the 2011 RFP is an estimate of energy sales, customer counts, and peak demand over a 20-year period. Significant inputs include information about regional and national economic growth, demographic changes, weather, prices, seasonality, and other customer usage and behavior factors. PSE also includes known large load additions or removal.

PSE used two different demand forecasts for portfolio analysis in the 2011 RFP:

(i) **F2011 Base load forecast** – PSE relied upon the F2011 Base load forecast for Phase I of the 2011 RFP and included such load forecast in the Screening Model.

(ii) **F2012 Base, Low, and High load forecasts –** PSE relied upon F2012 Base, Low, and High load forecasts for 2011 Phase II of the 2011 RFP. PSE delayed the RFP process in order to incorporate the F2012 load forecast in its final recommendations.

Q. Please describe the various F2012 load forecasts developed by PSE.

A. PSE based the F2012 Base load forecast on the February 2012 Moody's Analytics U.S. Macroeconomic Forecast (the "February 2012 Outlook") and developed the

F2012 High and Low load forecasts to develop distributions of load for risk analysis.

The February 2012 Outlook showed a delayed, but continued, recovery with real gross domestic product growth reaching near four percent by 2014. The unemployment rate also declined every year in the near-term, in lockstep with increasing total employment, which started to grow at a healthy pace by 2014. With manufacturing gaining strength and businesses beginning to hire more, there are some positive signs for an impending economic recovery. Risks to the economic outlook still exist. Economic problems in Europe, foreclosures preventing price stabilization in the U.S. housing market, job cuts by local governments, along with uncertain government action over the extension of programs such as payroll tax cuts and unemployment insurance programs, were all downside risks to the outlook at the time.

Q. How does the F2012 Base load forecast compare with the F2011 Load Forecast and the 2011 IRP Alternate Cyclical Low scenario?

A. The current regional economic forecast suggests worse results than the economic forecast underlying the F2011 Load Forecast but performs better than the economic forecast underlying the 2011 IRP Alternate Cyclical Low scenario. In most areas of the economy, the F2012 Base load forecast falls between the F2011 and the IRP Alternate Cyclical Low scenario, with housing recovery trending closer to the IRP Alternate Cyclical Low scenario through 2012. Housing recovery does come closer to the F2011 forecast levels through 2016 before slowing to near the Alternate Cyclical Low for the remainder of the forecast. Additionally, the F2012 load forecast reflects the loss of Jefferson County loads in April 2013.

Please see Exhibit No. ___(AS-14) and Exhibit No. ___(MM-3HC) at 91 for a comparison of how the load forecasts have changed since the F2010 load forecast used in the 2011 IRP.

Q. Did PSE also rely on a regional load forecast?

A. Yes. PSE used a forecast of regional load to develop power prices. In particular, PSE used the Northwest Power and Conservation Council's regional forecast from the Sixth Power Plan. Please see Exhibit No. ___(AS-15) and Exhibit No. ___(MM-3HC) at 92 for a depiction of the Northwest Power and Conservation Council's regional forecast, as well as high and low variations.

D. Generic Resources

Q. What assumptions did PSE make with respect to generic resources?

A. The generic resource assumptions used by PSE in Phase I of the 2011 RFP were the same as those assumptions used in the 2011 IRP, with the costs updated to 2012 dollars. Please see Exhibit No. ___(AS-16) and Exhibit No. ___(MM-3HC) at 104 for the generic resource assumptions for Phase I of the 2011 RFP.

PSE made three small updates to the generic resource assumptions in Phase II of the 2011 RFP. First, PSE updated the start date for generic resources from 2014 to 2015 to reflect the time it would take to construct a new plant. Second, PSE moved the start date for generic transmission additions to 2023. Finally, PSE updated the winter capacity value for the generic peakers to reflect PSE's 23 degree Fahrenheit design peak temperature instead of average January temperature. Please see Exhibit No. ___(AS-17) and Exhibit No. ___(MM-3HC) at 105 for the generic resource assumptions for Phase II of the 2011 RFP.

E. CO_2 Prices

Q. How did PSE evaluate CO_2 cost risk?

A. PSE used a single scenario—the Base + CO_2 scenario—to examine the impact of CO_2 costs on the selection of resources. PSE did not include CO_2 costs in the Base Case scenario because the current legislative climate suggests comprehensive carbon legislation is not likely in the near future. Please see Exhibit No. ___(AS-18C) for the CO_2 cost risk included in the Base + CO_2 scenario.

Q. How did PSE develop the CO_2 prices included in Exhibit No. ___(AS-18C)?

A. PSE developed the projected CO_2 prices in Exhibit No. ___(AS-18C) and Exhibit No. ___(MM-3HC) at 94 based on the projected CO_2 prices modeled and published by the U.S. Environmental Protection Agency in its analysis of the Kerry-Lieberman "American Power Act" cap-and-trade program. In this environment, gas prices and power prices reflect CO_2 costs. PSE included moderate CO_2 cost in the Base + CO_2 scenario.

Q. How did PSE document these assumptions?

A. PSE presented assumptions to PSE's Energy Management Committee, WUTC staff, and PSE's Board of Directors. The complete RFP documentation including the information presented in this prefiled direct testimony is included in the Seventh Exhibit to the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-8HC).

VI. TRANSMISSION ANALYSIS

Q. Did PSE use its quantitative models to evaluate transmission contracts?

A. Yes. PSE used its quantitative models to evaluate the following transmission contract renewals with BPA:

- the 23 megawatt ("MW") firm Cross-Cascades transmission capacity renewal;
- the Pacific Gas & Electric Seasonal Energy Exchange Agreement ("PG&E Exchange") firm transmission renewal and acquisition;
- the 400 MW Mid-C firm transmission renewal; and
- the 35 & 115 MW Mid-C firm transmission renewals.

Provided in Table 1 below is a summary of the BPA transmission contract renewals that were evaluated using quantitative modeling and the key underlying assumptions.

Table 1. Quantitative Analysis of BPA 2012 & 2013 Transmission Renewals

Resource	Renewal Deadline	Start Date	MW Capacity	Evaluation/ Decision	RFP/ IRP
Cross-Cascades	12/30/10	3/1/11	23	December 2011 & January 2012	2010/ 2009 & 2011 Draft
PG&E Exchange - Renewal	7/31/13	8/1/14	300	February 2013	2011/ Draft 2013
PG&E Exchange - New	7/31/13	8/1/14	300	February 2013	2011/ Draft 2013
Mid-C	8/31/12	11/1/12	400	August 2012	2011/ 2011
Mid-C	2/28/13	3/1/14	35	February 2013	2011/ Draft 2013
Mid-C	7/31/13	10/1/13	115	February 2013 & July 2013	2011/ Draft 2013

A. 23 MW Firm Cross-Cascades Transmission Capacity Renewal

Q. When did PSE evaluate the 23 MW firm Cross-Cascades transmission capacity renewal?

A. PSE evaluated the 23 MW firm Cross-Cascades transmission capacity renewal in December 2010 as PSE was completing PSE's 2010 Request for Proposals ("2010 RFP") and negotiating with entities on the 2010 RFP short list. At that time, PSE forecasted a capacity need of 646 MW in 2012, growing to more than 1,000 MW by 2017.

Q. Does the 23 MW firm Cross-Cascades transmission capacity renewal meet this capacity need?

A. Yes. The 23 MW firm Cross-Cascades transmission capacity renewal meets PSE's capacity need when redirected to the Mid-Columbia ("Mid-C") hub. Please see Mr. DeBoer's prefiled direct testimony, Exhibit No. ___(TAD-1T), for a description of the redirect process and how PSE uses the 23 MW firm Cross-Cascades transmission capacity renewal to meet PSE's capacity need.

Q. How did PSE evaluate the 23 MW firm Cross-Cascades transmission capacity renewal?

A. PSE compared the 23 MW firm Cross-Cascades transmission capacity renewal to the 2010 RFP short-list resources and other resources analyzed by PSE after identifying the short-list. The analysis relied upon the Portfolio Screening Model that was used in the final decision to enter into the 100 MW Klamath Peaker purchased power agreement ("Klamath Peaker PPA") with Iberdrola Renewables, LLC in March 2011.[3] In conducting its quantitative analysis, PSE evaluated the 23 MW firm Cross-Cascades transmission capacity renewal only as a five year renewal and did not consider potential rollover rights.

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[3] The fifty month contract with Iberdrola Renewables for 100MW of winter capacity and energy (November through March) associated with the Klamath Peakers for the term January 1, 2012 through February 29, 2016 (the "Klamath Peaker PPA").

Q. How did the cost of the 23 MW firm Cross-Cascades transmission capacity renewal compare to other capacity resource options?

A. Compared to the other resource alternatives from the 2010 RFP and revised bids at the time of the decision, the 23 MW firm Cross-Cascades transmission capacity renewal and redirect of the rights was the least-cost resource to meet PSE's near-term capacity need on a portfolio benefit ratio basis as shown in Table 2 below.

Table 2. 2010 RFP Resource Alternatives

2010 RFP Resources				
Resource	**Nameplate Capacity**	**Levelized $/MW**	**Benefit Ratio**	**Portfolio Benefit $000**
23 MW Mid-C Transmission Contract	23	N/A	2.743	$4,674
Klamath Peaker PPA	100	N/A	2.504	$24,167
[redacted]	[redacted]	[redacted]	0.925	$116,022
PSE Self Build	213	N/A	0.263	$50,660
[redacted]	[redacted]	[redacted]	0.207	$30,152
[redacted]	[redacted]	[redacted]	0.171	$35,065
[redacted]	[redacted]	[redacted]	0.029	$56,536

Q. How did the Klamath Peaker PPA and the 23 MW firm Cross-Cascades transmission capacity renewal compare on a capacity cost basis?

A. The dollar per kilowatt capacity cost (also described as the net cost metric) of the 23 MW firm Cross-Cascades transmission capacity renewal was lower than the dollar per kilowatt capacity cost of the Klamath Peaker PPA. The net cost is the difference in the project revenue requirement and the market revenue (value) of the project generation. Table 3 shows the average per kilowatt-year capacity cost of the transmission contract to be less than the Klamath Peaker PPA for the years where capacity need is met by both contracts.

Table 3. Annual Capacity Cost Comparison using PSE's 2010 RFP

$/KW-year (Net Cost)	2012	2013	2014	2015
23 MW Mid-C Transmission Contract	[redacted]	[redacted]	[redacted]	[redacted]
Klamath Peaker PPA	[redacted]	[redacted]	[redacted]	[redacted]

B. PG&E Exchange Firm Transmission Renewal and Acquisition

Q. When did PSE evaluate the PG&E Exchange?

A. PSE evaluated the PG&E Exchange and its associated BPA transmission costs in early 2013—at the same time that PSE evaluated the 35 MW and 115 MW Mid-C firm transmission renewals discussed below.

Q. Is there a need for the PG&E Exchange?

A. Yes. The Draft 2013 IRP considers the 300 MW PG&E Exchange an existing contract in perpetuity. If PSE or PG&E were to terminate the PG&E Exchange with the required five-year notice, PSE's capacity need would increase by 300 MW after expiration of the notification period.

Q. How did PSE quantitatively evaluate the PG&E Exchange?

A. PSE used the Draft 2013 IRP optimization model to evaluate the PG&E Exchange. This is the same model used by PSE to evaluate the 35 MW and 115 MW Mid-C firm transmission renewals discussed below.

Q. How does the increase in the transmission costs impact the economics of the PG&E Exchange?

A. As explained in the Prefiled Direct Testimony of Mr. Tom DeBoer, Exhibit No. ___(TAD-1T), there is an increase in the transmission costs associated with the PG&E Exchange beginning August 1, 2014. Table 4 below shows the annual capacity cost of the PG&E Exchange in comparison to the 2011 RFP resources. As shown in Table 3, the cost of the PG&E Exchange, including its increased costs from the second transmission wheel, is cost-effective as compared to the 2011 RFP resources.

Table 3. Annual Capacity Cost Comparison- 2011 RFP[4]

Annual Capacity Cost ($/kW-yr)[1]	2014	2015	2016	2017	2018	2019	2020	2021
35 and 115 MW (costs are the same for each contract)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PG&E Exchange (1 wheel tx, not an option)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PG&E Exchange (2 wheels tx)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Coal Transition PPA[2]	NA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ferndale Ownership	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted][3]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Generic Peaker- 2017	NA	NA	NA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
(1) Capacity cost is the same as the net cost metric; results presented are based on Draft 2013 IRP Base scenario only when the contract is included for the entire year
(2) Equity return of $2.92/MWh based on PSE's request in Docket UE-121373.
(3) Assumes PSE would [redacted].

4 Table 3 only compares capacity cost when the resource is available for the entire year.

Q. What did the results of the optimization analysis show for the PG&E Exchange?

A. The optimization model showed selection of the PG&E Exchange in the Draft 2013 IRP base case. Additional testing showed that a 20 year continuation of the PG&E Exchange, would result in an approximately $264 million portfolio benefit compared to termination of the agreement in 2019.

C. Other Mid-C Firm Transmission Contract Renewals and Acquisitions

1. 400 MW Mid-C Firm Transmission Renewal

Q. When did PSE evaluate the 400 MW Mid-C firm transmission renewal?

A. In August 2012, PSE analyzed the 400 MW Mid-C firm transmission renewal using the Optimization Model and in a manner consistent with the quantitative analyses undertaken by PSE in the 2011 RFP analysis.

Q. Did PSE have a need for the 400 MW Mid-C firm transmission renewal?

A. Yes. The 2011 IRP and 2011 RFP resource need assumed all Mid-C transmission held by PSE would be renewed and that the Mid-C market has enough winter regional surplus to support both PSE's current and additional Mid-C transmission. As explained in Exhibit No. ___(MM-3HC), PSE's 2011 RFP projected a resource need of 129 MW in 2012 and 681 MW in 2016. If PSE did not renew its Mid-C transmission, the need would increase by 400 MW to 529 MW in 2012 and 1,081 MW in 2016. Please see the Prefiled Direct Testimony of Mr. Michael

Mullally, Exhibit No. ___(MM-1HCT) for a detailed explanation of the RFP need.

Q. Did PSE quantitatively analyze the 400 MW Mid-C firm transmission renewal and compare such analyses to the 2011 RFP alternatives?

A. Yes. PSE analyzed the 400 MW Mid-C firm transmission renewal and compared such analyses to alternatives in the 2011 RFP version of the Optimization Model.

Q. Is the 400 MW Mid-C firm transmission renewal a lowest cost resource?

A. Yes. Today, Mid-C transmission, when coupled with power purchased at the Mid-C, is one of the lowest cost resources in PSE's power portfolio because many of PSE's owned resources require a BPA wheel and result in costs above market priced power. As shown in Table 4 below, the average per kilowatt-year ("kW-year") capacity cost of the Mid-C transmission is lower than the most favorable 2011 RFP resources.

Table 4. Annual Capacity Cost Comparison- 2011 RFP[5]

$/KW-year (Net Cost)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
400 MW Mid-C Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Coal Transition PPA	NA	NA	NA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ferndale Ownership	NA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Generic Peaker-2017	NA	NA	NA	NA	NA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. What were the results of the analyses?

A. The analyses confirmed that Mid-C transmission is the lowest cost resource alternative compared to 2011 RFP resource options. PSE's analyses considered 100 MW renewals for both a single five-year renewal and renewal of four consecutive five year renewals to equal 20 years. PSE found a portfolio benefit of $276 million for a five-year renewal and a $417 million benefit, assuming rollover rights were executed to create a 20-year term. These portfolios also selected the acquisition of Ferndale Generating Station and the Coal Transition PPA resources in addition to the 400 MW of Mid-C transmission renewals. Additionally, the 2011 RFP scenario analyses selected no less than 400 MW of Mid-C transmission renewals. Please see the Second Exhibit to the Prefiled Direct Testimony of Mr. Tom DeBoer, Exhibit No. ___(TAD-3HC) for a copy of the August 16, 2012 presentation to the Energy Management Committee

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5 Table 4 only compares capacity cost when the resource is available for the entire year.

("EMC"), which included the analyses results for the 400 MW BPA Mid-C transmission contract.

2. 35 & 115 MW Mid-C Firm Transmission Renewal

Q. Has PSE continued to evaluate its Mid-C transmission renewals and the amount of Mid-C transmission that it can rely upon in the future?

A. Yes. PSE continues to evaluate each transmission renewal and the amount of Mid-C transmission that it can rely upon. The most recent analysis in early 2013 considered 35 MW and 115 MW of Mid-C firm transmission renewals occurring in 2013.

Q. Does PSE's Draft 2013 IRP[6] continue to show a need for resources?

A. PSE's Draft 2013 IRP need from January 2013 projected a capacity surplus of 123 MW in 2014 and a capacity need of 22 MW in 2017.

Table 5. PSE Draft 2013 IRP Need (MW)[7]

Total Surplus/(Need) Base	2014	2015	2016	2017	2018	2019
2013 IRP	123	136	95	(22)	(71)	(114)
2013 IRP w/out 35 MW	88	101	60	(57)	(106)	(149)
2013 IRP w/out 115 MW	8	21	(20)	(137)	(186)	(229)
2013 IRP w/out 150 MW (35 + 115)	(27)	(14)	(55)	(172)	(221)	(264)

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6 The draft PSE 2013 IRP refers to PSE 2013 IRP draft presented to the IRP Advisory Group on January 22, 2013.

7 The amounts in Table 5 include all power to be delivered under the Coal Transition PPA. At the time of the analysis, the Commission had not rendered its final decision on PSE's reconsideration request with respect to the Coal Transition PPA in Docket UE-121373. The Coal Transition PPA contributes 180 MW of capacity in 2014, 280 MW of capacity in 2015 and 380 MW of capacity in 2017-2024, and 300 MW in 2025.

Q. How did PSE evaluate the 35 MW and 115 MW Mid-C firm transmission renewals?

A. PSE used the then-current 2013 IRP Optimization Model to evaluate the 35 MW and 115 MW Mid-C firm transmission renewals. The optimization analysis presented to the EMC on February 21, 2013, showed a least cost portfolio that (i) renewed the 115 MW Mid-C transmission contract; (ii) released the 35 MW Mid-C transmission contract; and (iii) requested new Mid-C transmission from BPA beginning in 2019. Please see the Fourth Exhibit to the Prefiled Direct Testimony of Mr. Tom DeBoer, Exhibit No. ___(TAD-5HC)

Q. Did the quantitative analyses consider PSE's likely ability to secure Cross-Cascades transmission in 2019?

A. No. The quantitative analyses did not consider PSE's likely ability to secure Cross-Cascades transmission in 2019. Additionally, the quantitative analyses did not consider PSE's ability to renew only a portion of the Mid-C transmission contract.

Q. How do Mid-C transmission renewals compare to the 2011 RFP resources?

A. In the 2013 analyses of Mid-C transmission renewals, PSE used BPA's proposed 2014 transmission rates published in the Federal Register on November 8, 2012. Even with BPA's proposed rate increases effective October 1, 2013, Mid-C transmission to Mid-C market remains a least cost resource.

Q. What was the decision on these two Mid-C transmission renewals?

A. As explained in the Prefiled Direct Testimony of Mr. Tom DeBoer, Exhibit No. ___(TAD-1T), PSE opted to renew only the 35 MW transmission contract and defer the decision for the 115 MW transmission contract until the renewal deadline of June 30, 2013. From a quantitative perspective, the extra time will allow PSE to complete its 2013 IRP analyses and incorporate any changes that may occur between the Draft 2013 IRP and models and the final 2013 IRP and models. PSE will file its 2013 IRP by May 31, 2013.

VII. CONCLUSION

Q. Does that conclude your prefiled direct testimony?

A. Yes, it does.