**EXHIBIT NO. ___(PKW-1CT)**
**DOCKET NOS. UE-17____/UG-17____**
**2017 PSE GENERAL RATE CASE**
**WITNESS: PAUL K. WETHERBEE**

**BEFORE THE**
**WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

| | |
|---|---|
| **WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,**<br><br>**Complainant,**<br><br>**v.**<br><br>**PUGET SOUND ENERGY,**<br><br>**Respondent.** | **DOCKET NO. UE-17____**<br>**DOCKET NO. UG-17____** |

# PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF PAUL K. WETHERBEE ON BEHALF OF PUGET SOUND ENERGY

**REDACTED VERSION**

**JANUARY 13, 2017**

**PUGET SOUND ENERGY**

**PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF PAUL K. WETHERBEE**

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**PUGET SOUND ENERGY**

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## I. INTRODUCTION

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

A. My name is Paul K. Wetherbee. My business address is 10885 NE Fourth Street, P.O. Box 97034, Bellevue, WA 98009-9734. I am the Director, Energy Supply Merchant for Puget Sound Energy ("PSE").

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

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

**Q. What are your duties as Director, Energy Supply Merchant at PSE?**

A. As Director, Energy Supply Merchant, my responsibilities include the following:

(i) managing the dispatch of PSE's portfolio of generation assets, related transmission, and associated environmental attributes;

(ii) directing the Front Office power and gas trading operations and the hedging program functions; and

(iii) oversight of the long-term gas transport capacity position.

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

A. This prefiled direct testimony addresses the following issues relevant to power costs for this proceeding's rate year—January 1, 2018 through December 31, 2018 (the "rate year"):

(i) PSE's power portfolio risks;[1]

(ii) PSE's structures and policies to manage these risks, including, but not limited to, hedging strategies;

(iii) the impact of the BPA's upcoming rate proceeding and renewal of and additions to PSE's transmission contracts with BPA;

(iv) the impact of PSE's new gas-for-power transportation contracts which provide access to natural gas resources for its natural gas-fired generation facilities;

(v) PSE's involvement in the CAISO Energy Imbalance Market ("EIM") and the treatment of PSE's costs associated with the EIM in power costs in this proceeding;

(vi) the impact of Washington's Clean Air Rule ("CAR") on PSE's energy supply operations;

s(vii) PSE's projected rate year power costs for this proceeding, including changes in resources available to PSE to meet customer demand;

(viii) a comparison of PSE's projected rate year power costs for this proceeding to those currently in rates; and

(ix) a status of the White River surplus properties.

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[1] The electric "portfolio" consists of resources available to PSE to serve its customers. The electric portfolio includes generation facilities, purchased power, gas transportation, gas storage and transmission capacity.

**Q. What is the basis for the power cost rates that are in place today?**

A. In September 2016, in Docket UE-161135, PSE filed with the Commission a limited update to its power costs (**“**2016 Power Cost Update**”**). These new power costs projections were based on the final power costs in the 2014 power cost only rate case **(“**PCORC**”)**, which was the last proceeding in which the Commission completed a full review of PSE**’**s power costs. In this limited update, input assumptions related to the Centralia Coal Transition purchase power agreement, forward gas prices, and hedged volumes were updated, and power costs were re-estimated given these changes. The rates from this update were allowed to go into effect by operation of law effective December 1, 2016.

Because the 2016 Power Cost Update included only limited changes to the 2014 PCORC, this testimony describes PSE’s analysis in this proceeding relative to the analysis in the 2014 PCORC. Comparisons to current rates relate to the 2016 Power Cost Update.

**Q. How do the proposed costs compare with costs currently in rates?**

A. PSE**’**s power cost projections for the rate year are higher than the amount set in rates effective December 1, 2016 as a result of the 2016 Power Cost Update by $31.2 million, or 4.4 percent. A primary reason for the increase in projected power costs from those currently set in rates is the impact of compliance with the Clean Air Rule (**“**CAR**”**). Other causes of increases to power costs include updates to existing contracts, higher load, and transmission rate increases. These increases to power costs are partially offset by lower costs related to expiration of certain contracts. The proposed power costs are $7.1 million below the amount approved in the 2014 PCORC.

## II. VOLATILITY AND RISK IN PSE'S ELECTRIC RESOURCE PORTFOLIO

**Q. What is the nature of PSE's load and resources to serve that load?**

A. PSE's electric load is primarily driven by residential and commercial customers, with a portion coming from industrial customers. Forecasted load for the 2018 rate year is 2,657 average megawatts ("aMW") with a peak demand of 4,990 MW. The difference between average energy and peak demand illustrates the seasonal nature of PSE's load. PSE owns a mix of thermal, wind and hydroelectric resources to serve its load. These resources alone are not sufficient to meet customer demand in all hours of the year. Therefore PSE relies on contracts with non-utility generators and market purchases to meet its load. PSE holds transmission capacity that enables it to buy and sell power on the market, primarily at the Mid-C trading hub.

**Q. Why is energy risk management a concern to PSE?**

A. PSE's controlled resources are not sufficient to meet PSE's load obligation at all times, and under certain market conditions it is more economical to buy power on the market and wheel it to the load center than to run PSE's generating units. PSE engages in market transactions to supplement its owned resources and provide reliable electric service every hour of every day at a reasonable cost to customers.

PSE's power resource portfolio is subject to significant volatility and risk that ultimately have a substantial impact on energy costs.

**Q. What drives volatility and risk in the power portfolio?**

A. PSE's power supply portfolio contains a diverse mix of resources with widely differing operating and cost characteristics. Although there are many complex variables embedded in the portfolio, the major drivers of power cost volatility are:

(i) streamflow variation affecting the supply of hydroelectric generation;

(ii) weather and economic uncertainty affecting power usage;

(iii) variations in market conditions resulting in changes to wholesale gas and electric prices;

(iv) risk of forced generation outages;

(v) variability of wind generation; and

(vi) transmission and transportation constraints.

All of these have an impact on load and resources, which PSE may balance with wholesale market purchases and sales.

**Q. Please describe the volatility related to variations in streamflow affecting hydroelectric supply.**

A. There are four main variations in streamflow that affect hydroelectric supply:

(i) below average runoffs;

(ii) average runoffs;

(iii) above average runoffs; and

(iv) the timing or shape of the runoff.

During an average streamflow year, 20 percent of PSE's electric load is met by hydroelectric resources. During poor streamflow conditions, PSE may need to purchase supplemental power or run gas-fired generating units more than it otherwise would in order to serve its customer load, both of which are more costly than hydro resources. During favorable streamflow conditions, PSE may need to purchase less or sell surplus power in the wholesale power markets to balance its supply portfolio which can greatly affect PSE's power costs. The regional market price of power is heavily influenced by hydro conditions each year. Typically, market power prices tend to be higher during a "dry" (or below average runoff) year and lower during a "wet" (or above average runoff) year. In all of the runoff conditions, the timing or shape of the runoff also influences the market price of power.

**Q. Please describe the volatility that is related to load and temperature uncertainty.**

A. The level of PSE's electric retail load is correlated with temperature. The correlation of load and temperature is especially apparent considering how PSE's load increases as temperatures decline during the winter heating season. In light of the significant electric heating load in PSE's service territory, PSE's costs related to load and temperature uncertainty can be significant.

Although still a winter peaking utility, PSE also experiences summer peaking demand. This is due in part to increasing use of electric air conditioning and presents another example of electric load volatility attributable to temperature.

**Q. Please describe the risks related to market price volatility.**

A. The previously discussed volume-related risks directly affect PSE's exposure to market prices. As resource generation and load demand change, PSE may be subject to significant price-related risk associated with the expected volume of purchases and sales of power in the wholesale markets and the need to purchase or sell natural gas in connection with the operation of its gas-fueled generating units.

**Q. Please describe the volatility related to forced outages.**

A. As shown in Table 1 below, for the rate year, PSE will rely on approximately 2,581 megawatts ("MW") of thermal generating units to help meet its customer loads.

**Table 1. PSE's Thermal Generation Units**

| | |
|---|---|
| Colstrip Generating Station | 658 MW |
| Goldendale Generating Station | 300 MW |
| Mint Farm Generating Station | 314 MW |
| Ferndale Generating Station | 271 MW |
| Frederickson Generating Station | 134 MW |
| Encogen Generating Station | 166 MW |
| Sumas Generating Station | 123 MW |
| Simple Cycle Combustion Turbines | 615 MW |
| **Total MW** | **2,581 MW** |

The capacities shown in Table 1 represent the current operational capacities at International Standard Organization conditions. These units include:

(i) 658 MW of large, base-load coal generation with low variable fuel costs;

(ii) 1,308 MW of gas-fired, combined-cycle combustion turbines with moderate heat rates; and

(iii) 615 MW of relatively less-efficient, simple-cycle gas and oil-fired combustion turbine generation.

Equipment failure, fire, electrical disturbances, transmission outages or other such events typically cause forced outages. Forced outages at any of these units can expose PSE to significant price volatility in its power supply portfolio.

**Q. Please explain the variability of wind generation.**

A. PSE's power portfolio benefits from 823 MW of wind generation. Wind resources, however, have significant variability as evidenced by comparing short-term wind generation forecasts to actual generation. PSE must manage this short-term generation variability by:

(1) purchasing wind integration services from BPA;

(2) reshaping contracted Mid-C hydro generation; and

(3) utilizing other generating assets within its system to accommodate the variable output of the wind facilities.

Such reshaping takes place on a day-ahead and real-time basis and affects PSE's power costs as PSE must adjust other resources' generation levels on a day-ahead and real-time basis to accommodate forecast and actual fluctuations in wind generation. Table 2 below provides a summary of PSE's expected rate year wind generation and capacity.

**Table 2. PSE's Wind Generation Capacity**

| Resource | Capacity (MW) | # Turbines | Rate Year Generation (MWhs) | Capacity Factor |
|---|---|---|---|---|
| Hopkins Ridge | 157 | 87 | [redacted] | [redacted] |
| Wild Horse | 229 | 127 | [redacted] | [redacted] |
| Wild Horse Expansion | 44 | 22 | [redacted] | [redacted] |
| LSR Phase 1 | 343 | 149 | [redacted] | [redacted] |
| Klondike III PPA | 50 | N/A | [redacted] | [redacted] |
| **Total** | **823** | **385** | **2,074,320** | **N/A** |

**Q. What risks are related to transmission and transportation constraints?**

A. PSE is exposed to transmission and natural gas transportation risks, such as pipeline outages, curtailments of transmission due to de-ratings,[2] and forced outages. For example, if power cannot be wheeled[3] from the Mid-C trading hub to PSE's system, PSE would be forced to meet load by dispatching other resources or making market purchases from unconstrained points that may be higher cost.

**Q. Are PSE's power costs subject to other risks?**

A. Yes. Examples of other risks to PSE's power costs include, but are not limited to counterparty credit risk and execution risk. Counterparty credit risk refers to the risk of default by PSE's counterparties on contractual obligations. Execution risk refers to the ability to execute wholesale market transactions and includes, for

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[2] De-rating refers to a decrease in the rated electric capability of an electric transmission line.

[3] Wheeling refers to the use of the transmission facilities of one power system to transmit power of and for another system. This term is often used colloquially to mean transmission.

example, counterparty credit requirements, PSE's credit standing, and contractual requirements.

## III. PSE'S MANAGEMENT OF POWER COST RISK

**Q. How does PSE manage the volatility of power costs?**

A. PSE has had organizational structures, policies and overarching strategies in place for many years to provide oversight and control of PSE's energy portfolio management activities, many of which must be undertaken on an hourly and daily basis by PSE's experienced energy traders. PSE also uses modeling tools that assist in projecting whether its power and gas portfolios will be surplus or deficit in future periods. PSE uses these tools to develop and implement hedging strategies to reduce the supply and cost risks associated with the power portfolio volatility.

**Q. Please summarize PSE's efforts with respect to developing and implementing hedging strategies for its electric portfolio.**

A. PSE manages its electric portfolio within a dynamic and complex environment by relying on:

- internal organizations and trained staff dedicated to managing portfolio risks;
- executive and Board of Director-level oversight of staff's portfolio management activities;
- specific procedures and policies governing energy portfolio management activities;

- production cost modeling techniques that develop a 250 scenario probabilistic view of PSE's wholesale electric portfolio and its underlying risks;
- use of programmatic hedging strategies that specify a range of monthly volumes to be hedged, depending upon market fundamentals and energy portfolio management staff's expertise;
- revision of strategies to incorporate up-to-date fundamental views of energy commodity markets;
- a $350 million unsecured revolving credit agreement to support PSE's energy hedging activities; and
- a counterparty credit risk system.

**Q. Has PSE revised its hedging program since the 2014 PCORC?**

A. No. PSE's hedging program is unchanged since PSE's 2014 PCORC.

**Q. What are the hedges included in rate year power costs?**

A. The rate year power costs include gas-for-power and power contracts that were transacted as of September 23, 2016, for delivery during the rate year (calendar year 2018).

Table 3 below provides a summary of the fixed-price rate year power portfolio hedges included in rate year power costs.

**Table 3. PSE's 2017 GRC Rate Year**
**Short-Term Fixed Price Power Portfolio Hedges**
**at September 23, 2016**

| | **MWh Volume** | **Rate Year Cost** | **Avg. $/MWh** |
|---|---|---|---|
| On-Peak Power Purchases | [redacted] | [redacted] | [redacted] |
| Off-Peak Power Purchases | [redacted] | [redacted] | [redacted] |
| Total Power Purchases | [redacted] | [redacted] | [redacted] |
| On-Peak Power Sales | [redacted] | [redacted] | [redacted] |
| Off-Peak Power Sales | [redacted] | [redacted] | [redacted] |
| Total Power Sales | [redacted] | [redacted] | [redacted] |
| Net Power Fixed | [redacted] | [redacted] | [redacted] |

| | **Dth Volume** | **Rate Year Cost** | **Avg $/Dth** |
|---|---|---|---|
| Net Financial Gas for Power | [redacted] | [redacted] | [redacted] |

As discussed below, to determine rate year power costs, the fixed-price gas-for-power contracts are marked to market in the "Costs not in AURORA" calculation, and the fixed-price power contracts are included within the AURORA model.[4] In addition, PSE has entered into physical power and gas-for-power contracts for the rate year, which are priced at plus or minus index. The premiums and/or discounts for index contracts are also included in the "Costs not in AURORA" calculation.

[4] The AURORA model is discussed in Section IX. A of this prefiled direct testimony.

**Q. Please expand on the types of hedges included in rate year power costs.**

A. PSE hedges power or gas-for-power to fix the price of the commodity. PSE utilizes either fixed-for-float swaps[5] to financially hedge power and natural gas-for-power or fixed price physical power and gas for power. The mechanics of a financial fixed-for-float swap, in combination with a physical index purchase, result in a price position identical to purchasing fixed price physical supply.

PSE is able to transact with counterparties through standard agreements for financial swaps and fixed price physical power. PSE's market counterparties may only be able to sell physically, financially, or, in some cases, both. Therefore, liquidity is enhanced by transacting both physically and financially.

## IV. BPA'S 2018-2019 RATE CASE

**Q. Are BPA transmission rates expected to change before or during the rate year?**

A. Yes. BPA is in the process of a combined power and transmission rate proceeding to set new rates for BPA's fiscal years 2018-2019 (October 1, 2017, through September 30, 2019) (the "BPA 2018 Rate Case").

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[5] Fixed-for-float swaps fix the price of a commodity relative to the market "index" price of a commodity and settlement is done financially. For example, PSE may enter into a fixed-for-float Mid-C power contract for a future month at a fixed price of $32.00 per MWh for all hours of the day ("flat"). When the future month occurs, the contract is settled by comparing the fixed $32.00 per MWh to the market price of, say $35.00 per MWh. In this example, the counterparty would pay PSE the difference between the fixed price and the market price, or $3.00 per MWh. For a 31-day month with 744 hours, this would be a payment of $2,232 for a 1 MWh contract.

**Q. Is PSE participating in the BPA 2018 Rate Case?**

A. Yes. PSE is an intervener in the BPA 2018 Rate Case to advocate for PSE customers' interests to ensure any rate changes are supported by the facts presented. Consistent with past practice, PSE will likely work with other parties to sponsor joint testimony recommending ways to reduce the rate increases.

**Q. How does PSE propose to include BPA's planned transmission rate changes in rate year power costs?**

A. PSE has included projected BPA transmission rate increases and decreases as published on November 10, 2016 in the Federal Register, effective October 1, 2017, in the pro forma transmission costs included in the rate year power cost forecast. BPA may update its projected rate changes in the 2018 BPA Rate Case during the course of this proceeding, and PSE will update rate year power costs to reflect any such changes.

## V. TRANSMISSION CONTRACT RENEWALS

**Q. Please provide an overview of the transmission contracts renewed or acquired for the rate year.**

A. PSE uses transmission to wheel power from both its owned and contracted resources to PSE's system to serve load. In addition to relying on its own transmission, PSE also relies extensively on BPA transmission contracts to transmit generated or purchased power to PSE's system so that PSE may meet customer demand and ensure power is provided continuously during a peak demand event. A large portion of the BPA transmission is used to wheel short-term market purchases at the Mid-C hub to meet PSE's capacity need as explained in PSE's 2015 Integrated Resource Plan (the "2015 IRP").[6] These transmission contracts are an integral part of PSE's electric resource portfolio and are necessary to provide capacity and energy. PSE has renewed five BPA transmission contracts to be used to access short-term market purchases at the Mid-C hub.

Additionally, PSE has renewed three contracts to allow for continued delivery from an existing plant or a power purchase agreement or to meet a generating resource's station service load requirement. PSE also renewed one contract for short-term purchases in Montana. PSE entered into one new BPA transmission contract on a conditional firm basis to complement a generation capacity increase at an existing facility, Mint Farm Generating Station ("Mint Farm"), and has requested to change the status of that Mint Farm transmission contract from conditional firm to firm. PSE has also requested to enter into two new BPA transmission contracts to complement a generation capacity increase at another existing PSE facility, Goldendale Generating Station ("Goldendale").

**Q. Has PSE prepared a summary of transmission renewals and additions for the rate year?**

A. Yes. Table 4 shows BPA transmission contracts that have expired or will expire before the end of the rate year, as well as new transmission contracts with BPA.

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[6] *See* Puget Sound Energy, Inc., 2015 Integrated Resource Plan, Chapter 6 (Electric Analysis) (November 30, 2015), available at http://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx.

**Table 4. BPA Transmission Contract Renewals & Additions**

**Mid-C Transmission Renewals**

| Resource | Renewal Deadline | Start Date | Megawatt Capacity |
|---|---|---|---|
| Vantage | 2/28/15 | 3/1/16 | 23 |
| Rocky Reach | 10/31/16 | 11/1/17 | 100 |
| Rock Reach | 10/31/16 | 11/1/17 | 100 |
| Midway | 10/31/16 | 11/1/17 | 100 |
| Vantage | 10/31/16 | 11/1/17 | 100 |
| **Total** | | | **423** |

**Transmission Renewed or Added for Resources and Station Service**

| Resource | Renewal Deadline | Start Date | Megawatt Capacity |
|---|---|---|---|
| Coal Transition PPA | 9/30/15 | 10/1/16 | 100 |
| Mint Farm | 11/30/14 | 12/1/15 | 12 |
| Mint Farm Station Service | 5/31/15 | 6/1/16 | 8 |
| Montana Purchases | 9/30/15 | 10/1/16 | 94 |
| **Total** | | | **214** |

**New Transmission Requests in BPA's Queue**

| Resource | Requested Start Date | Megawatt Capacity |
|---|---|---|
| Mint Farm Conditional Firm[7] | 5/1/17 | 15 |
| Goldendale | 5/1/16 | 18 |
| Goldendale | 11/1/17 | 20 |
| **Total** | | **53** |

7 PSE has received the 15 MW of transmission for Mint Farm on a conditional firm basis and has requested that it be made firm.

## A. Transmission Contract Renewals

### 1. Mid-C Transmission Renewals

**Q. How does PSE determine the appropriateness of renewing firm Mid-C transmission?**

A. As Mid-C transmission contracts become eligible for renewal, PSE evaluates the costs and risks of Mid-C resources using a similar approach and the same tools it uses to evaluate generation assets for acquisition. PSE compares the cost of transmission contracts to other resource alternatives to fill in resource need based on models developed in the IRP.

**Q. When does PSE evaluate the Mid-C transmission renewals?**

A. PSE evaluates the costs and benefits of renewing its Mid-C transmission contracts one year and two months prior to their expiration date. Renewing the current transmission contract one year prior to expiration enables PSE to execute right of first refusal. The two additional months are required for PSE to meet its internal review process. The analysis is presented to the Energy Management Committee ("EMC") twice. The first presentation is to explain the analysis and request for decision. The second, or final, presentation is a decisional presentation at which the EMC members vote to decide if the transmission contract purchase or renewal should be made.

PSE will continue to evaluate Mid-C transmission contracts and will have the opportunity to make adjustments to its total Mid-C transmission capacity available to meet customers' peak capacity need as other Mid-C transmission contracts come up for renewal. At that time, PSE will have the option to reduce its Mid-C transmission capacity if new information results in a different conclusion than analysis of previous renewals.

**Q. Please describe PSE's 23 MW Vantage transmission contract with BPA.**

A. The 23 MW Vantage contract was originally associated with the Spokane Municipal Waste Power Purchase Agreement, which expired in December 2011. When this Power Purchase Agreement was approaching expiration PSE decided to utilize its position within BPA's queue and redirect the 23 MW of transmission to the Mid-C instead of terminating the transmission contract at its expiration date. At the time of that redirect, BPA suggested that PSE's ability to obtain Mid-C transmission in the future was very limited and uncertain. In January 2015, PSE completed an analysis and decided it would be cost-effective to permanently redirect the 23 MW contract from Spokane to the Mid-C and renew the contract for another five year term. On February 19, 2015, the EMC approved the request to renew the 23 MW Mid-C firm transmission contract with BPA.

**Q. Please summarize PSE's approach to the analysis related to renewing the 23 MW Mid-C firm transmission contract.**

A. PSE compared (i) the incremental portfolio cost of generation resources assuming renewal of the 23 MW transmission contract with (ii) the incremental portfolio cost of generation resources assuming expiration of the contract. PSE used this comparison to determine whether there was an economic benefit to renewing the transmission contract. PSE's incremental portfolio cost of generation includes variable costs of PSE's existing generation assets, all capital and operating and maintenance costs associated with new units necessary to meet peak capacity and Renewable Portfolio Standard ("RPS") requirements over 20 years, and end effects of new resources. End effects include residual costs of new resources beyond the 20-year window through the useful life of the assets plus the replacement costs for those assets.

**Q. How does PSE calculate the portfolio costs?**

A. PSE calculates the portfolio costs on a net present value basis using the Portfolio Screening Model III ("PSM III"). PSM III is an optimization model PSE uses to minimize the net present value of portfolio costs while meeting both its peak capacity and RPS requirements. PSE also uses PSM III to develop its IRP and to evaluate bids for generation resources provided by outside parties in response to Requests for Proposals. The PSM III model contains data from the most recent IRP and ongoing IRP work. For the 23 MW Vantage contract the starting point was an update to the 2013 IRP with capital costs for alternative resources from the 2015 IRP. The model includes data on PSE-owned resources and forecasted load, financial data, forecasted dispatch from the AURORA production cost model, and costs of alternative resources such as natural gas-fired combined cycle units, peaking units and wind resources.

**Q. Please describe the AURORA dispatch model.**

A. AURORA is a fundamentals-based production cost model that simulates hourly economic dispatch of generation resources within the Western Electricity

Coordinating Council region of the United States. PSE uses energy, cost, revenue and price data related to PSE assets and potential new assets from the AURORA model in its PSM III model.

**Q. Are the transmission costs assumed in the analysis of the 23 MW Vantage contract renewal consistent with those included in the rate year power costs?**

A. PSE started with the BPA tariff rates effective at the time of the analysis, and assumed a growth rate of 6.1 percent every two years. The growth rate was based on preliminary information provided by BPA in a BP-16 rate case workshop in August 2014. The analysis was performed before BPA issued the BP-16 Final Record of Decision in July 2015 and therefore did not incorporate actual increases effective October 2015. As discussed in Section IV, “BPA’s 2018-2019 Rate Case,” the actual increases that took effect October 2015 are incorporated into the estimated projected power costs for the rate year.

**Q. What were the results of the analysis?**

A. The analysis showed that renewing the 23 MW Mid-C transmission contract resulted in a lower portfolio cost as compared to allowing the transmission contract to expire in February 2016. The net present value of the incremental portfolio cost with and without the renewal is presented in Table 5.

**Table 5. Net Present Value of Portfolio Costs with and without 23 MW Vantage Renewal**

| Option | Incremental Portfolio Cost ($000) | Portfolio Benefit to Renewal ($000) |
|---|---|---|
| Renewal | $10,324,354 | $14,288 |
| No Renewal | $10,338,642 | |

**Q. Why is there a portfolio benefit to the transmission contract renewal?**

A. The transmission contract with BPA allows PSE to delay building some generation capacity during the planning horizon, which results in a lower net present value of portfolio costs.

**Q. Is this finding consistent with previous analysis of the 23 MW transmission contract?**

A. Yes. PSE evaluated the cost-effectiveness of renewing this transmission contract in 2010 and presented that analysis in its 2013 PCORC in Docket UE-130617. The current analysis confirms this earlier conclusion that renewal of the contract was prudent.

**Q. Could PSE renew only a portion of the 23 MW Mid-C firm transmission contracts?**

A. Yes. PSE had the option to renew all or any portion of the 23 MW Mid-C firm transmission contract. However, if PSE relinquishes any transmission capacity there is a risk, given the current state of available Mid-C capacity, of not being able to reacquire needed Mid-C transmission in the future.

**Q. What are some of the risks associated with acquiring new Mid-C firm transmission in the future?**

A. New Mid-C firm transmission is requested through BPA's transmission queue and requires participation in a future Transmission Service Request Study and Expansion Process ("TSEP"), formerly known as Network Open Season. The BPA Network Open Season that concluded in May of 2014 showed that current

Transmission Service Requests requesting service from the Mid-C will impact a constrained transmission path. New Mid-C firm transmission requests require capacity on multiple constrained BPA flowgates. The most prominent BPA flowgate affecting a new Mid-C firm transmission request is the Cross-Cascades North flowgate. The Cross-Cascades North flowgate is highly constrained, with no available winter month capacity through 2025, as posted on the BPA website. At the time of the decision to renew PSE's 23 MW Mid-C transmission contract in February 2015, BPA's transmission queue indicated there was no available transmission capacity on the Cross-Cascades North flowgate through 2024. As of December 20, 2016, there was approximately 1,500 MW of transmission demand in the BPA pending queue in excess of capacity on the Cross-Cascades North flowgate in 2025.[8]

**Q. Please describe PSE's four 100 MW Mid-C transmission contracts with BPA.**

A. PSE has four existing Mid-C transmission contracts, each having 100 MW, that would expire in October 2017. PSE has renewed these four contracts for the minimum term of five years to retain renewal rights and to allow flexibility to reevaluate transmission needs in the future. Current information from BPA suggests PSE's ability to obtain Mid-C transmission in the future is limited and uncertain, hence if PSE does not renew these contracts, it might be difficult to get back the transmission capacity in the future. Renewing these four contracts is

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[8] According to the ATC Less Pending Queued Request Inventory that is publically posted on the BPA website.

appreciably less expensive than building an equivalent natural gas peaker plant to replace lost peak capacity.

**Q. Please summarize PSE's approach to the analysis related to renewing the four 100 MW Mid-C firm transmission contracts.**

A. PSE analyzed these contracts using the same approach it used to evaluate the 23 MW Vantage contract but with an updated version of PSM III from the 2015 IRP. PSE compared (i) the incremental portfolio cost of generation resources assuming renewal of all four 100 MW transmission contracts with (ii) the incremental portfolio cost of generation resources assuming expiration of the contracts. PSE used this comparison to determine whether there was an economic benefit to renewing the transmission contracts.

**Q. What were the results of the analysis?**

A. The analysis showed that renewing the 400 MW Mid-C transmission contracts resulted in a lower portfolio cost as compared to allowing the transmission contracts to expire in October 2017. The net present values of the incremental portfolio costs with and without the renewal are presented in Table 6.

**Table 6. Net Present Value of Portfolio Costs with and without 400 MW Renewal**

| Option | Incremental Portfolio Cost ($000) | Portfolio Benefit to Renewal ($000) |
|---|---|---|
| Renewal | $7,777,077 | – |
| No Renewal | $8,019,874 | $242,797 |

### 2. Existing Generation Resource/Load Transmission Renewals

**Q. Did PSE renew any BPA transmission contracts used to wheel power from existing resources?**

A. Yes. PSE renewed four transmission contracts to allow continued delivery of power from existing market resources. The four contracts are listed in Table 7 and described below.

**Table 7. BPA Existing Generation Transmission Renewals**

| Resource | Renewal Deadline | Start Date | End Date | Megawatt Capacity |
|---|---|---|---|---|
| Coal Transition PPA | 9/30/15 | 10/1/16 | 9/30/21 | 100 |
| Mint Farm | 11/30/14 | 12/1/15 | 11/30/20 | 12 |
| Mint Farm Station Service | 5/31/15 | 6/1/16 | 5/31/21 | 8 |
| Montana Purchases | 9/30/15 | 10/1/16 | 9/30/21 | 94 |
| **Total Transmission Renewed for Resources and Load** | | | | **214** |

#### a. Transmission Contract (100 MW) Serving the Coal Transition PPA

**Q. Please describe the 100 MW contract serving the Coal Transition PPA.**

A. The Coal Transition PPA is an existing agreement that extends through 2025; the facility is interconnected to BPA's transmission system. Power from the facility is wheeled to PSE's system in part using a 100 MW transmission contract with BPA which would have expired September 30, 2016. PSE renewed the contract for five years (until September 20, 2021) to allow continued delivery of power from the facility.

### b. Two Transmission Contracts (12 MW and 8 MW) Serving Mint Farm

**Q. Please describe the 12 MW and 8 MW contracts associated with Mint Farm.**

A. PSE owns and operates Mint Farm. Power from the facility is wheeled, in part, to PSE's system using a 12 MW transmission contract which would have expired November 30, 2015. PSE renewed the contract for five years (until November 30, 2020) to allow continued delivery of power from the facility. Power is wheeled to the facility to provide station service using an 8 MW transmission contract which would have expired June 1, 2016. PSE renewed the contract until May 31, 2021 to allow continued delivery of power to the facility.

### c. Transmission Contract (94 MW) Associated with Purchases from Garrison, Montana

**Q. Please describe the 94 MW contract associated with purchases from Garrison, Montana.**

A. The 94 MW transmission contract provides transmission from Garrison, Montana to the PSE system. It had an expiration date of September 30, 2016. PSE used this transmission to wheel power from a two year short-term 75 MW physical index power purchase transacted for the winter months November 2013 through February 2014 and November 2014 through February 2015. This transmission capacity also provides an alternative path, receiving at Garrison 230 kV substation, to wheel power from PSE's generation assets in Montana in the event of outages or derates on the 500 kV transmission system. It also provides access to short-term power purchases at the Garrison hub at prices that are generally below Mid-C prices.

**Q. When did PSE evaluate the 94 MW transmission contract?**

A. PSE evaluated the contract in September 2015.

**Q. Please summarize PSE's approach to evaluating the 94 MW contract.**

A. Because this transmission contract supported a specific physical index power purchase, PSE evaluated it in conjunction with the assumed replacement of the winter peaking physical index power purchase that had expired in February 2015.[9] Three portfolios were developed. The first included the transmission/physical index power purchase combination, the second excluded it, and the third included a 75 MW peaker built in 2016 instead of the transmission/ physical index power purchase combination.

**Q. What assumptions did PSE make in evaluating the 94 MW contract?**

A. PSM III had been updated for the 2015 IRP, so the transmission renewal analysis was based on the version of PSM III used in the draft 2015 IRP Base Scenario as it stood at the time. Optimal demand side resources chosen in the draft 2015 IRP were included in the portfolio. The transmission contract was assumed to be renewed throughout the 20-year planning horizon. It was priced based on BPA tariff rates in effect at the time of the analysis with escalation of 6.1 percent every

[9] The assumed short-term replacement contract was a 75 MW winter only (November through February) power purchase contract that would begin in November 2015.

two years. The terms of the expired physical index power purchase were assumed throughout the 20-year planning horizon. Specifically, the power was priced at [redacted] and the contract was for winter months November through February.

**Q. What were the results of the analysis?**

A. The portfolio analysis shows a portfolio benefit associated with the 94 MW transmission renewal. Comparison of the portfolios with and without the transmission renewals indicates that the addition of peaking capacity in the years beyond 2026 can be delayed if the contract is renewed. In addition, the portfolio that included the transmission renewal was able to meet capacity need with a lower cost portfolio consisting of a combination of three peakers and one combined cycle plant as opposed to the portfolio without the renewal, which contained two peakers and two combined cycle plants to meet capacity need. Replacing a combined cycle build with a peaker build results in a lower capital cost. The effect of these differences was a $27 million portfolio benefit to renewal.

Comparison of the portfolio containing the transmission renewal to the portfolio with an equivalent amount of peaking capacity indicates a nearly $99 million portfolio savings when the transmission renewal is executed.

Results of the portfolio analysis are presented in Table 8.

**Table 8. Net Present Value of Portfolio Costs with and without 94 MW Renewal**

| Option | Incremental Portfolio Cost ($000) | Portfolio Benefit to Renewal ($000) |
|---|---|---|
| Renewal with Physical Index Power Purchase | $9,783,440 | – |
| No Renewal | $9,810,719 | $27,279 |
| Partial Peaker | $9,882,387 | $98,947 |

**Q. Did PSE replace the Physical Index Power Purchase for power at Garrison?**

A. Yes. PSE procured a winter only 75 MW physical index power purchase for three winters under PSE's portfolio hedging program. It started in November 2015 and will expire in February 2018.

**Q. Was the transmission contract for power at Garrison, Montana approved by PSE's EMC?**

A. Yes. The EMC approved the renewal of the 94 MW transmission contract from Garrison on September 17, 2015.

**Q. Were the transmission contracts renewed for Mint Farm and the Coal Transition PPA also approved by PSE's EMC?**

A. No, these contract renewals were not submitted to the EMC because EMC approval was not necessary. If a transmission contract supports an underlying resource and the new contract term is within the operating life of the existing facility, PSE policy does not require EMC approval of the contract renewal.

**Q. Are all of the resources for which transmission was renewed included in the rate year power cost forecast?**

A. Yes. PSE's rate year power resources include the Coal Transition PPA, Mint Farm, and the 75 MW winter only physical index power purchase.

### 3. Summary of Transmission Contract Renewals

**Q. Was PSE's renewal of BPA transmission capacity a valuable and reasonable business decision?**

A. Yes. As noted above, PSE relies on existing BPA transmission contracts from Mid-C to PSE's system to meet its capacity need in that PSE may use this transmission to wheel short-term market power from Mid-C to PSE's load. In this regard, these types of transmission contracts are akin to a resource for PSE and provide needed capacity. Additionally, firm transmission is required for PSE's generation resources and contracts in order to ensure reliable delivery to PSE's system to serve load. In all cases, PSE performed a full and detailed justification for the prudence of the costs of renewing and acquiring these BPA transmission contracts.

**Q. What does PSE request from the Commission regarding PSE's renewal of transmission contracts?**

A. PSE respectfully requests the Commission deem these contracts and expenses to be prudently incurred and allow PSE to fully recover these costs in rates.

Specifically, PSE requests the Commission approve the rate year transmission costs presented in Table 9.

**Table 9. PSE Rate Year BPA Transmission Contracts Renewal Costs**

| Resource | Rate Year Power Cost ($000) |
|---|---|
| Mid-C 423 MW | $9,147 |
| Coal Transition PPA 100 MW | $2,162 |
| Mint Farm 12 MW | $259 |
| Mint Farm Station Service 8 MW | $173 |
| Garrison 94 MW | $2,033 |
| **Total** | **$13,774** |

## B. New and Potential New Transmission for Existing Generation Facilities

**Q. Does PSE plan to acquire new BPA transmission contracts to wheel power from existing resources?**

A. Yes. PSE plans to enter into three new transmission contracts to allow for additional delivery of power from existing resources. The three contracts are listed in Table 10 and described below.

**Table 10. BPA New Generation Transmission Contracts**

| Resource | Requested Start Date | End Date | Megawatt Capacity |
|---|---|---|---|
| Goldendale | 11/1/17 | 11/1/22 | 20 |
| Mint Farm | 5/1/17 | 5/1/22 | 15 |
| Goldendale | 5/1/16 | 5/1/21 | 18 |
| **Total New Transmission for Resources** | | | **53** |

### **1. Transmission Contract (20 MW) Associated with Goldendale**

**Q. Please describe the 20 MW contract associated with Goldendale.**

A. In October of 2014 PSE decided to acquire an additional 20 MW of transmission capacity from BPA in order to accommodate the duct firing capabilities of the Goldendale generation facility. The previous transmission rights, totaling 277 MW, were acquired from the previous owner and did not cover the entire capacity potential of the Goldendale generation facility when the facility is duct firing.

**Q. When did PSE evaluate the 20 MW transmission contract?**

A. PSE evaluated the contract in September 2014.

**Q. Please summarize PSE's approach to evaluating the 20 MW contract.**

A. Because this transmission contract supported an existing PSE owned generation facility, PSE evaluated it by comparing the cost of the transmission contract with the cost of a 25 MW winter peak call option.

**Q. What were the results of the analysis?**

A. This analysis showed that the additional transmission capacity would cost less than the winter peak call option. The additional transmission would allow PSE to operate its facility at its full potential.

**Q. Was the transmission contract for the 20 MW at Goldendale approved by PSE's EMC?**

A. Yes. The EMC approved acquiring the additional 20 MW of transmission for Goldendale on October 16, 2014.

### 2. Transmission Contracts (15 MW and 18 MW) Associated with Mint Farm and Goldendale, Respectively

**Q. Please describe the 15 MW and 18 MW contracts PSE is attempting to acquire for additional capacity at the Mint Farm and Goldendale generation facilities.**

A. PSE reviewed its contractual services agreements for both Mint Farm and Goldendale in October of 2015. From this review PSE discussed with General Electric contractual services agreement benefits that could be realized if PSE were to renegotiate the contract. From this negotiation, PSE decided to implement generator programming upgrades that would yield additional capacity from Mint Farm and Goldendale. PSE has requested an additional 15 MW of transmission capacity for Mint Farm and 18 MW for Goldendale from BPA, consistent with current interconnection agreements for both facilities.

**Q. Were the transmission contracts for the 15 MW and 18 MW at Mint Farm and Goldendale, respectively, approved by PSE's EMC?**

A. Yes. The EMC approved acquiring the 15 MW and 18 MW transmission contracts for Mint Farm and Goldendale, respectively, on October 15, 2015.

**Q. What is the current status of the requested transmission contracts for the 15 MW and 18 MW at Mint Farm and Goldendale, respectively?**

A. PSE received approval from BPA for the 15 MW for Mint Farm on a conditional firm basis. PSE entered into the contract for conditional firm service, and re-entered BPA's queue to have this capacity changed to firm service. PSE is still waiting to hear from BPA with respect to the 18 MW at Goldendale.

**Q. Are all of the resources for which new transmission will potentially be acquired included in the rate year power cost forecast?**

A. Yes. PSE's rate year power resources include the Mint Farm and the two Goldendale transmission contracts. However, PSE is currently waiting in BPA's queue to be offered firm transmission service. PSE will update power costs during the course of this proceeding, and the update will reflect the transmission approved and signed by BPA for the Mint Farm facility and the Goldendale facility should it differ from the 15, 18 and 20 MW contracts PSE requested.

### 3. Summary of the Potential New Transmission Contracts for Existing Generation Facilities

**Q. Is the benefit from the additional generation and transmission capacity at Goldendale and Mint Farm included in the rate year power cost forecast?**

A. Yes. The rate year power cost forecast includes the upgraded capacity of 38 MW and 15 MW to the Goldendale and Mint Farm facilities, respectively, and lowered heat rates for both plants.

**Q. Was PSE's initiation of acquiring the additional BPA transmission capacity a valuable and reasonable business decision?**

A. Yes. As noted above, PSE relies on existing BPA transmission contracts from Mid-C to PSE's system to meet its capacity need in that PSE may use this transmission to wheel short-term market power from Mid-C to PSE's load. In this regard, these types of transmission contracts are akin to a resource for PSE and provide needed capacity. Additionally, firm transmission is required for PSE's generation resources and contracts in order to ensure reliable delivery to PSE's system to serve load. In all cases, PSE performed a full and detailed justification for the reasonableness of the costs of renewing and acquiring these BPA transmission contracts.

**Q. What does PSE request from the Commission regarding PSE's potential new transmission contracts for existing generation facilities?**

A. PSE respectfully requests the Commission deem these contracts and expenses to be prudently incurred and allow PSE to fully recover these costs in rates. Specifically, PSE requests the Commission approve the rate year transmission costs presented in Table 11.

**Table 11. PSE Rate Year BPA Transmission New Contracts Costs**

| Resource | Rate Year Power Cost ($000) |
|---|---|
| Mint Farm 15 MW | $325 |
| Goldendale 18 MW | $389 |
| Goldendale 20 MW | $432 |
| **Total** | **$1,146** |

## VI. NATURAL GAS RESOURCES

### A. Overview of Gas Transportation

**Q. Please describe the gas resources held by PSE for power generation.**

A. PSE maintains a diverse portfolio of firm pipeline capacity and firm storage capacity to provide reliable fuel supply to the generation fleet. The capacity currently held will meet (i) 100% of PSE's combined-cycle combustion turbine requirements on a year-round basis, (ii) approximately one-half of the winter-time requirements of its simple-cycle combustion turbine requirements, and (iii) approximately one-third of the summer-time requirements of its simple-cycle combustion turbine requirements.

PSE also holds firm transportation capacity upstream of the two major pipeline interconnects at Sumas, Washington, and Stanfield, Oregon, to ensure the availability of supply at those points and to diversify the pricing of the supply. Such upstream capacity is equivalent to approximately 50% of PSE's requirements at those points. For generating facilities situated on the distribution system of Cascade Natural Gas Company ("Cascade Natural Gas"), PSE has reserved the necessary firm distribution service to ensure reliable deliveries of fuel acquired upstream.

PSE has contracted for firm storage service to provide reliability, flexibility, and, in conjunction with special firm storage redelivery service, incremental supply to the generation fleet in the winter months. The storage service provides necessary reliability and flexibility to start or stop generation as needed during the gas day by providing an immediate supply of fuel or a place to store the gas and avoid a pipeline imbalance. The storage also serves as an integral part of the portfolio to allow incremental deliveries in winter months because it is coupled with winter-only pipeline capacity at significantly reduced cost. PSE's storage service capacity can also serve as an alternate supply source to avoid extreme pricing deviations at either of the major supply points.

Table 12 below details the firm natural gas resources held by PSE to serve its generation fleet.

**Table 12. Natural Gas Resources for PSE Gas-Fired Generators**

**Firm Pipeline Service Capacity**

| Pipeline | Path | Capacity (Dth/d) | Annual[1] Demand Cost ($000) |
|---|---|---|---|
| Northwest Pipeline | Sumas to Plants | 108,957 | 11,818 |
| Northwest Pipeline | Stanfield or Plymouth to Plants | 78,928 | 11,812 |
| Northwest Pipeline | Plymouth or Stanfield to Plants | 15,000 | 557 |
| Total Northwest Pipeline Annual | | 202,885[2] | 24,187 |
| Northwest Pipeline-Winter Only | Jackson Prairie to Plants | 34,197[2] | 1,270 |
| Total Northwest Pipeline Winter | | 237,082 | 25,457 |
| Cascade Natural Gas | Sumas to Whitehorn | 24,000[2] | 11 |
| Cascade Natural Gas | Sumas to Ferndale | 52,000[2] | 984 |
| Cascade Natural Gas | Northwest Pipeline to Encogen | 37,000 | 197 |
| Cascade Natural Gas | Northwest Pipeline to Fredonia | 94,000 | 1,527 |
| Cascade Natural Gas | Northwest Pipeline to Mint Farm | 52,000 | 833 |
| Northwest Pipeline | Goldendale Lateral | 52,000 | 129 |
| Puget Sound Energy | Sumas Pipeline | 26,000[2] | – |
| Westcoast Energy | Station 2 to Sumas | 86,143 | 7,145 |

(1) Expected cost for the rate year: January 2018 through December 2018
(2) Capacity included in Total Capacity to plants
(3) Withdrawal capacity is subject to recall

**Table 12. Natural Gas Resources for PSE Gas-Fired Generators (continued)**

**Firm Pipeline Service Capacity**

| Pipeline | Path | Capacity (Dth/d) | Annual[1] Demand Cost ($000) |
|---|---|---|---|
| NGTL | NIT to A/BC | 41,420 | 1,879 |
| Foothills Pipeline | A/BC to Kingsgate | 40,946 | 978 |
| Gas Transmission NW | Kingsgate to Stanfield | 40,567 | 2,292 |
| Total Capacity to Plants | Annual | 304,885 | |
| | Winter | 339,082 | |
| Total Pipeline Demand Charge | | | 41,450 |

**Firm Storage Service**

| Project | Withdrawal Capacity (Dth/d) | Storage Capacity (Dth) | Annual[1] Demand Cost ($000) |
|---|---|---|---|
| Northwest Pipeline Plymouth LNG | 70,500 | 241,700 | 958 |
| Northwest Pipeline Jackson Prairie | 6,704 | 140,622 | 67 |
| Jackson Prairie Storage Project (interbook) | 50,000[3] | 500,000 | 980 |
| Total Storage Service | 127,204 | 882,322 | |
| Total Storage Demand Charge | | | 2,005 |
| Total Gas Resource Demand Charge | | | 43,455 |

(1) Expected cost for the rate year: January 2018 through December 2018

(2) Capacity included in Total Capacity to plants

(3) Withdrawal capacity is subject to recall

## B. New and Renewed Resources

**Q. Please describe changes to the gas pipeline resources that have taken place since the 2014 PCORC.**

A. PSE has acquired resources since rates were set in the 2014 PCORC. In general, they were related to supply at Stanfield, Plymouth Liquefied Natural Gas ("Plymouth LNG"), and Sumas.

**Q. Please explain the resources related to supply at Stanfield.**

A. PSE's generation portfolio currently relies on a ready supply of approximately 79,000 Dth/d of gas at the Northwest Pipeline ("NWP") Stanfield interconnect with TransCanada's Gas Transmission Northwest ("GTN"). The GTN system accesses gas from Alberta via TransCanada's Foothills Pipeline ("Foothills Pipeline") and Nova Gas Transmission, Ltd. ("NGTL") systems. PSE has become concerned about the availability of uncommitted supply at Stanfield and the potential for significant price differentials between abundant supplies at the upstream NGTL trading hub, (known as NIT or AECO-C), and Stanfield, due to declining capability of NGTL to flow gas to the Foothills Pipeline system. Consistent with PSE's strategy of holding 50% of upstream capacity from the Stanfield and Sumas hubs, PSE acquired these contracts:

- 37,913 Dth per day with NGTL from NIT to the Alberta-British Columbia border effective December 1, 2015;
- 3,507 Dth per day with NGTL from NIT to the Alberta-British Columbia border effective January 1, 2016;
- 40,946 Dth per day with Foothills Pipeline from the Alberta-British Columbia border to Kingsgate effective December 1, 2015; and
- 40,567 Dth per day with GTN from Kingsgate to Stanfield effective November 1, 2015.

**Q. Please explain the resources related to Plymouth LNG.**

A. In 2014 PSE determined that the secondary firm pipeline capacity related to PSE's Plymouth LNG storage service contract was no longer a reliable form of service during the coldest times of year. Northwest Pipeline confirmed that there had been changes to flow patterns that affected the reliability of this secondary firm service. As a result PSE gave notice of termination of the Plymouth LNG contract effective October 31, 2015.

Subsequently, NWP worked with PSE to create a package that included a Plymouth LNG contract and winter-only firm transportation capacity that would firm up a portion of PSE's simple-cycle combustion turbine fleet. PSE re-acquired the Plymouth LNG storage capacity as part of the package of resources from NWP and third parties arranged by NWP. This package of resources was for the benefit of the PSE power generation portfolio and resulted in a cost savings relative to alternative resources. These transactions provide PSE with pipeline and storage resources at less than 40 percent of the cost of conventional year-round pipeline capacity and less than the expected cost of future expansion capacity.

The package included the following transactions related to Plymouth LNG:

- Plymouth LNG storage with Northwest Pipeline that provides 70,500 Dth per day demand and 241,700 Dth storage capacity effective November 1, 2015;
- 34,197 Dth per day winter only with Northwest Pipeline from Jackson Prairie to Longview and Sedro-Woolley effective November 1, 2015; and
- 15,000 Dth per day with Northwest Pipeline from Plymouth to Sedro-Woolley, with segmentation at Jackson Prairie, effective November 1, 2015.

**Q. Please explain the resources related to supply at Sumas.**

A. In late summer 2015, PSE was approached by another shipper that had determined it no longer required its 30,000 Dth per day of firm pipeline capacity on NWP from Sumas to a location just north of a major constraint point on Northwest Pipeline's system near Chehalis, Washington. The shipper was prepared to discount the price of the capacity if PSE would take over the contract in October 2015 for its remaining term through September 2018.

PSE pursued negotiations with NWP about acquiring this capacity. As a result of these negotiations PSE acquired 20,000 Dth per day from Sumas to Jackson Prairie for the term of October 1, 2015, through October 31, 2033, at a rate of approximately 35% of the current tariff rate until September 30, 2018. This capacity provides additional firm capacity to the generation fleet that will allow additional Sumas-sourced gas to flow to any of PSE's simple-cycle combustion turbine units on Northwest Pipeline and, under most conditions, to Mint Farm along with guaranteed access (through the major constraint point) for injection into Jackson Prairie in all cases. The capacity supplements the entire portfolio by increasing the total firm fuel reliability of PSE's simple-cycle combustion turbine units on the Northwest Pipeline.

**Q. Has PSE renewed any storage agreements?**

A. Yes. PSE's power book contracts for the use of some of PSE's firm capacity in the Jackson Prairie Storage Project from the gas book. The current internal "inter-book" contract became effective on April 1, 2016. PSE's gas book determined that it was able to implement the new inter-book storage contract on substantially similar conditions and at the same cost as the prior agreement, which expired on March 31, 2016, as a result of:

(i) the decline in forecast design peak-day requirements for future years;

(ii) the successful renewal of certain firm transportation agreements; and

(iii) the recent acquisition of 10,000 Dth per day of new firm pipeline capacity.

Under the inter-book storage agreement the power book has firm, uninterrupted access to 500,000 Dth of storage capacity for use as (i) incremental supply (when used with incremental transportation capacity); (ii) supply for mid-day dispatch; (iii) a balancing account for surplus gas supply; and (iv) a price mitigation tool. The generation portfolio also has use of firm withdrawal and injection rights of up to 50,000 Dth per day, except when withdrawal rights may be recalled by the gas book. The inter-book storage agreement specifies that the gas book can recall the firm withdrawal rights for a brief period each winter in order to ensure that the gas book can serve the design peak requirements of gas customers. However, the power book is allowed to utilize a portion of best efforts withdrawal rights available to PSE on the days of recall. The gas book does not have access to the inventory held in Jackson Prairie by the power book.

**Q. How did PSE treat costs related to gas storage contracts in the rate year revenue requirement?**

A. PSE has three contracts related to gas storage that are used for the electric generating units. These include a contract with NWP for storage at Jackson Prairie, a contract with NWP for LNG storage at Plymouth, and a contract with

PSE's gas book for storage at Jackson Prairie. The costs of these three contracts are included in rate year power costs and presented in Table 12.

The Jackson Prairie storage currently contracted with NWP has been included in rate year power costs since it was put into rates in the 2009 GRC. The Plymouth contract started in 2015, and because it provides the same type of service that the NWP Jackson Prairie contract provides, PSE included it in rate year power costs also. Previous versions of the Jackson Prairie inter-book contract were included in production O&M. The newest inter-book contract, effective in April 2016, is included in rate year power costs because it serves the same function as the two NWP storage contracts.

**Q. Why is storage considered a power cost?**

A. Gas storage is an integral part of the overall transportation of fuel to the generating site. This was acknowledged by FERC in Order 636, in which FERC amended 18 C.F.R. Section 284.1(a) to read as follows: "Transportation includes storage, exchange, backhaul, displacement or other methods of transportation." FERC subsequently required FERC-jurisdictional storage to be subject to the same rate design, contracting and capacity release rules as gas transportation. Gas storage is an integrated component of gas transportation service and is used on a daily basis to afford the efficient management of fuel supply for generation, and is properly considered a fuel cost.

Some of the firm transportation contracts used by PSE to transport fuel to the generating sites are only available for use if the supply they are transporting originates from either Jackson Prairie or Plymouth. This makes storage integral to gas transportation, which has long been considered a fuel cost.

## C. Pipeline Capacity Costs

**Q. Does PSE anticipate significant changes to pipeline rates during the rate period?**

A. Yes. Pursuant to a 2012 FERC approved settlement with customers Northwest Pipeline is obligated to either file a FERC Section 4 rate case for new rates to become effective January 1, 2018 or reach a new settlement for rates effective January 1, 2018. PSE and other shippers are currently engaged in negotiations with Northwest Pipeline that are currently expected to result in a settlement agreement that would be approved by the FERC to be effective January 1, 2018.

In addition, PSE expects the Canada National Energy Board ("NEB") to approve adjustments to the rates of Westcoast, NGTL and Foothills Pipeline effective on January 1, 2018 and April 1, 2018 under the normal Canadian regulatory process. If FERC or NEB approval (as appropriate) is achieved during the pendency of this case, PSE will include adjustments to the pipeline rates and related gas costs when power costs are updated.

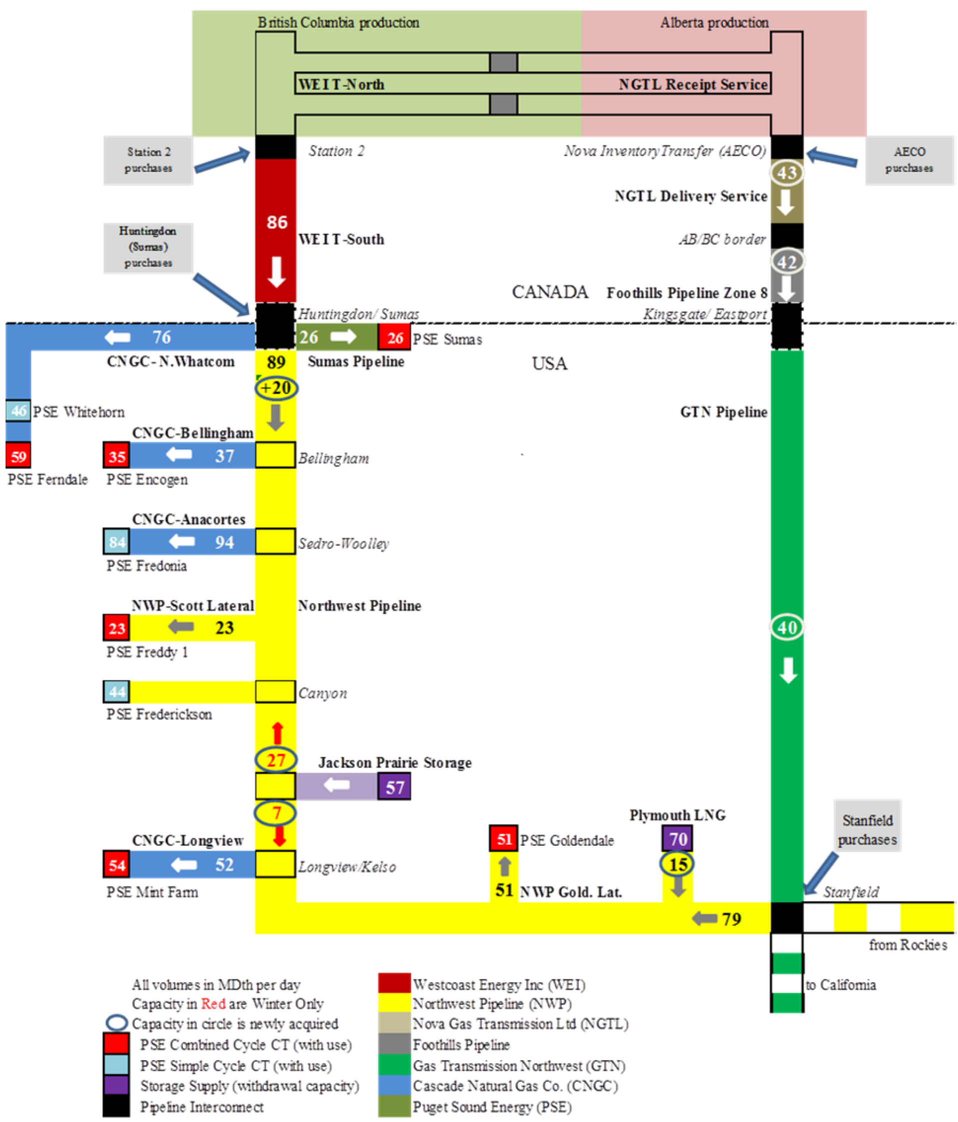
## D. Graphic Representation of Natural Gas Resources Held by the Gas-for-Power Portfolio

**Q. Has PSE prepared a graphic representation of the natural gas resources held by the gas-for-power portfolio that reflect the changes described above?**

A. Yes. Please see Picture 1 for graphic representation of the natural gas resources held by the gas-for-power portfolio that reflect the changes described above.

**Picture 1. Natural Gas Resources Held by the Gas-for-Power Portfolio**

Supply Locations, Pipeline Capacity and Storage Capacity as of January 2016



## VII. ENERGY IMBALANCE MARKET

**Q. What is the Energy Imbalance Market ("EIM")?**

A. The EIM is a voluntary, within-hour energy market that provides Balancing Authorities ("BA") another tool to reliably and economically maintain balance between electric demand (load) and supply (generating resources). It is operated by a central market operator who optimizes the generation resources of the BAs within the EIM footprint every fifteen and five minutes. The California Independent System Operator ("CAISO") serves as the market operator for the EIM in which PSE operates. Historically, energy has been predominately traded among entities through bilateral transactions of hourly energy products. Within the hour there has been no liquid market for energy, and BAs had to rely on their own generating resources to continuously match imbalances in load and non-dispatchable generation. The EIM provides a sub-hourly market that enables BAs to transact and utilize lower-cost resources in other BAs to balance load and resources. Ahead of each operating hour participating BAs may bid their generating resources into the EIM. The EIM market operator integrates all bids into its Security Constrained Economic Dispatch software, which settles and clears a five minute energy market for imbalances across the entire EIM footprint. The EIM does not replace bilateral, day-ahead, or hour-ahead markets and scheduling procedures that exist in the Western Interconnection today. The EIM is complementary to FERC Order 764, Integration of Variable Energy Resources.

CAISO and PacifiCorp launched the EIM on November 1, 2014. NV Energy joined the CAISO EIM in 2015. PSE and Arizona Public Service joined the

CAISO EIM on October 1, 2016. Portland General Electric has announced its intentions to join the CAISO EIM in 2017, and Idaho Power and Seattle City Light each plans to join in 2018 and 2019, respectively.

**Q. Why did PSE decide to be a part of the EIM?**

A. Intra-hour generation variability has increased in recent years with the influx of variable energy resources ("VERS"). The EIM provides a mechanism for managing this variability, allows for greater efficiency in sub-hourly dispatch, and may potentially allow for reductions in load following reserve requirements.

**Q. What costs and benefits are included in rate year power costs due to the EIM?**

A. The rate year increase to power costs in FERC Account 557, Other Expenses, due to PSE's participation in the EIM is forecast at $2.3 million. Benefits of approximately $8.5 million are also included in power costs. This benefit amount exactly offsets the sum of power cost expenses and rate base related expenses that are included in the revenue requirement. For more information on EIM costs in rate base please refer to Exhibit No. ___(KJB-7). The benefits are all included in power costs because any financial benefits PSE realizes will ultimately flow through power costs. Because benefits are included to exactly offset the estimated costs, there is zero net cost impact from EIM. PSE took this approach because the magnitude of benefits PSE will incur in the rate year is not known and measurable at this time.

**Q. What do the forecasted EIM power costs include?**

A. Table 13 provides a breakdown of the $2.3 million EIM rate year power costs.

**Table 13. Projected Rate Year Power Costs**

| **Resource** | **Rate Year Power Cost ($000)** |
|---|---|
| PSE Labor | $[redacted] |
| Software | $[redacted] |
| Legal and Administrative Fees | $[redacted] |
| **Total** | **$2,333** |

## VIII. WASHINGTON'S CLEAN AIR RULE

**Q. What is the Clean Air Rule?**

A. The Clean Air Rule ("CAR") was established in September 2016 by the Washington State Department of Ecology ("Ecology") under the state's Clean Air Act. Its purpose is to establish greenhouse gas emission standards for certain large emitters and reduce greenhouse gas ("GHG") emissions. It establishes GHG emission standards for certain stationary sources, petroleum product producers and importers, and natural gas distributors. It requires covered parties to essentially cap their emission of greenhouse gases starting in 2017 and reduce their emissions thereafter.

Initially, covered parties that are responsible for 100,000 metric tons of GHG emissions annually are required to reduce their emissions or offset those emissions beginning in 2017. This 100,000 ton threshold is reduced every three years until it reaches 70,000 metric tons in 2035. Actual average emissions for 2012-2016 will be used to determine whether a party exceeds the threshold. The rule contains a description of how the baseline cap for each stationary source will be established and reduced over time by the Department of Ecology.

**Q. Which of PSE's generating plants are likely to have caps?**

A. Based on the description of caps in the rule and historical emissions data, PSE estimates that six of PSE's ten natural gas fired generation plants will have caps effective in the first compliance period, which is 2017-2019. The rule also applies to the remaining four gas fired plants, but their historical emissions are below the threshold for participation in the caps in the first compliance period. The six units that PSE expects to have caps are all combined-cycle units, and they are Encogen, Ferndale, Frederickson 1 (combined-cycle), Goldendale, Mint Farm and Sumas. PSE expects four plants with simple-cycle combustion turbines to be below the initial threshold. They are Frederickson 1 & 2 (simple-cycle units), Fredonia 1 & 2, Fredonia 3 & 4, and Whitehorn.

**Q. How will PSE's electric operations be impacted by CAR?**

A. To comply with the rule, PSE will have to either reduce its use of these plants below historical levels and below the optimal levels projected in AURORA's economic dispatch for the rate year or acquire offsets. In order to meet its load, PSE will have to acquire energy through market purchases and alter the way it uses other dispatchable resources to meet load.

**Q. How did PSE account for the impacts of CAR in its rate year power costs in this proceeding?**

A. PSE calculated emissions caps for its combined cycle units consistent with the methodology described in the rule. These limits were placed on the units in AURORA, the hourly dispatch model used to forecast power costs, and the model was run with the emissions constraints in place. The AURORA output reflects the dispatch of PSE resources and market purchases with the CAR emissions limits in place.

## IX. PROJECTED RATE YEAR POWER COSTS

### A. Overview of Projected Power Costs for this Proceeding

**Q. What is included in PSE's power costs?**

A. Power costs include the costs of fuel to run generating units, purchased power, and third party transmission. Specifically, power costs include costs of coal, gas and oil to run thermal generators, long term power purchase agreements, other market purchases and sales, fixed and variable costs of upstream natural gas transportation and storage, BPA transmission, and various other power costs.

**Q. Please quantify PSE's net power cost projection for this proceeding.**

A. As shown in Table 14 below, PSE's projected rate year net power costs are $745.3 million.

**Table 14. Projected Rate Year Power Costs ($ in thousands)**

| | |
|---|---|
| AURORA | $493,630 |
| Costs not in AURORA | $251,646 |
| **Projected Rate Year Power Costs** | **$745,276** |

Please see Exhibit No. ___(PKW-3) for PSE's projected rate year net power costs. Please also see the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ___(KJB-1T), for the adjustment of PSE's projected rate year power costs to test year levels and the Prefiled Direct Testimony of Ronald J. Roberts, Exhibit No. ___(RJR-1CT), for PSE's projected rate year production operations and maintenance costs.

**Q. Please describe how PSE projected its net power costs in this proceeding.**

A. PSE developed projected power costs for the rate year months January 2018 through December 2018 based on the information available to PSE during the preparation of the initial filing in this proceeding. These projected power costs are consistent with PSE's prior rate cases except as otherwise noted.

As in prior cases, PSE used the AURORA hourly dispatch model to project a portion of its net power costs for the rate year. The remaining rate year power costs were calculated outside of the AURORA model and are referred to as "Costs not in AURORA."

**Q. Is the AURORA model used in power costs the same as that used for evaluating transmission renewals?**

A. The AURORA software is the same program used for transmission renewals discussed earlier in this testimony. However, the AURORA analysis used to estimate power costs for the rate year in this proceeding is distinct from the AURORA data used to evaluate transmission contracts discussed earlier in this testimony.

**Q. What costs are projected using the AURORA model?**

A. In the power costs analysis, AURORA produces a forecast of regional power prices and the dispatch of PSE's generating units. The variable costs of fuel for PSE's resources, certain long-term power purchase agreements, and other market purchases and sales are estimated by AURORA and included in rate year power costs.

**Q. Were there changes made to the AURORA hourly dispatch model since the 2014 PCORC?**

A. Yes. EPIS, Inc. ("EPIS"), the developer of the AURORA hourly dispatch model, provides periodic software and database updates. The software version of AURORA used in this filing is Version 12.1.1057, which EPIS issued on August 1, 2016. The database used is the North American Database 2015.01 ("2015.01 Database"), which EPIS issued in April 2015. EPIS updated the resource, demand, financial, and regional data within the 2015.01 Database to reflect more recent data, information and economic conditions than those included in the AURORA database used in the 2014 PCORC.[10]

**Q. Is AURORA Version 12.1.1057 the most recent version of AURORA available?**

A. No. EPIS recently issued Version 12.2.1025 on November 17, 2016—long after PSE had begun its power cost modeling for this filing.

**Q. Please explain PSE's projected "Costs not in AURORA" power costs that are not calculated within the AURORA hourly dispatch model.**

A. Consistent with prior cases, PSE's projected power costs also include costs that are not calculated within the AURORA hourly dispatch model and are called "Costs not in AURORA". "Costs not in AURORA" include items such as fixed coal supply costs (variable coal costs are included in AURORA), mark-to-market for fixed-price gas for power contracts and basis differentials (fixed-price power contracts are included in AURORA), premiums and discounts associated with contracts priced at plus or minus index, fixed gas transportation charges (variable gas transportation charges are included in the AURORA model), contract costs for the Mid-C hydroelectric projects, amortization of regulatory assets, other power supply costs, peaking capacity costs, wind integration costs, transmission expenses, distillate fuel testing incremental costs, transmission reassignment

[10] AURORA software version 11.3.1021 was used in the 2014 PCORC and 2016 Power Cost Update, along with the North American Database 2014.01.

revenues, and any other power supply costs not included in the AURORA hourly dispatch model.

**Q. Have any new items been added to "Costs not in AURORA" since the 2014 PCORC?**

A. Yes, three items have been added. As discussed above, PSE incurs costs associated with the EIM. Rate year forecasted power costs of $2.3 million are included as a "Cost not in AURORA," and approximately $8.5 million of power costs benefits are included to offset both the $2.3 million of power costs and the $6.1 million of rate base related costs.

**Q. What is the second item that has been added to "Costs not in AURORA" since the 2014 PCORC?**

A. The costs of balancing reserves and contingency reserves are a cost not in AURORA. These costs are in addition to the wind integration cost that was included in the 2014 PCORC. While AURORA is a powerful least-cost dispatch model, it does not fully incorporate PSE's real time capacity reserve obligations into its dispatch of generating resources. PSE uses its Hour Ahead Balancing Model to estimate all of the costs of balancing generation with load on an hour ahead basis.

**Q. What are contingency reserves?**

A. As a Balancing Authority, PSE is required by the North American Electric Reliability Corporation ("NERC") to fulfill a Contingency Reserve Obligation. Contingency reserves are capacity reserves that Balancing Authority operators are required to provide to help maintain the stability of the bulk power system during system disturbance events such as a generating unit tripping offline or an unexpected transmission line outage. They are incremental reserves, which means the Balancing Authority operator must have the ability to increase generation in the event of a disturbance to maintain its Contingency Reserve Obligation. In the WECC, contingency reserves are defined as three percent of the load in the Balancing Authority plus three percent of online generation located within the Balancing Authority. Fifty percent of the Contingency Reserve Obligation must be maintained by generating units that are online (spinning), and up to 50 percent can be provided by units that are offline but can be brought online within 10 minutes (non-spinning).

**Q. What are balancing reserves?**

A. A Balancing Authority operator must have sufficient capacity reserves available to continuously balance load and generation with its Balancing Authority pursuant to NERC and WECC reliability criteria. As loads and output from generating resources vary within an hour, the Balancing Authority operator must re-dispatch generation in real time so that overall Balancing Authority load equals overall Balancing Authority generation on an instantaneous basis. The contingency reserves described above cannot be used for balancing and therefore create additional costs for PSE. The need for balancing reserves is driven by variability in both the output from generating resources and load. Balancing reserves are both incremental and decremental, that is, the Balancing Authority operator must be able to either increase or decrease generation on short notice.

**Q. How are balancing and contingency reserves related to wind integration?**

A. Balancing reserves relate to variability in both generation and load. Since the 2007 GRC, PSE has included hour-ahead wind integration costs in its revenue requirement. These costs are a portion of the costs of maintaining balancing reserves specifically related to PSE's Wild Horse Wind Facility. Wind integration costs do not include the costs related to the variability of other generating resources in the Balancing Authority or load. They are specific to wind only. Contingency reserves must be maintained in addition to balancing reserves and, again, create additional costs.

**Q. Why is PSE including balancing and contingency reserve costs in this proceeding?**

PSE is obligated to hold a portion of its resources in reserve to meet these reserve obligations. Managing these reserves requires holding back generation that would otherwise be used to meet the company's load obligations. The forgone generation is then replaced with higher cost power. The wind integration costs, as previously included in rates, are only a portion of the total costs.

**Q. How did PSE calculate its balancing and contingency reserves costs?**

A. Because AURORA does not incorporate PSE's real time reserve obligations into its dispatch of PSE's generating resources, PSE calculates these costs outside of AURORA using its Hour Ahead Balancing Model. PSE used a SAS based version of the Hour Ahead Balancing Model to calculate wind integration costs in the 2013 and 2014 PCORCs. The current version of the model is Excel based and is capable of estimating balancing reserves and operating reserves, including the wind integration reserves that have historically been included in the revenue requirement. There were four steps to quantifying the hour-ahead costs:

1. Determine the overall hour ahead balancing and contingency reserve need;

2. Perform a re-dispatch of PSE's generation resources from the AURORA model so that the resulting dispatch accounts for balancing and contingency reserves. This requires two runs of the Hour Ahead Balancing Model, one that includes all reserve requirements and one that includes only the Contingency Reserve Obligation;

3. Calculate allocation factors that identify the relative contributions of Wild Horse Wind Facility, load, and third party generation in the Balancing Authority to balancing reserve requirements;

4. Allocate the estimated balancing reserve costs to Wild Horse Wind Facility, load, and third party generation in the Balancing Authority based on these allocation factors, and remove the third party generation costs from the total because they are not recovered from rates established in this proceeding.

**Q. Please summarize the estimated hour ahead balancing and contingency reserves costs.**

A. Table 15 presents the results of this analysis. Total balancing and contingency reserves included in the revenue requirement are $3.6 million as presented in Table 15 and included in Exhibit No.___(PKW-4).

**Table 15. Hour Ahead Balancing and Contingency Reserves Costs ($000)**

| | Total Rate Year Costs | |
|---|---|---|
| **Hour Ahead Balancing Model Results** | | |
| All Reserves Costs | $6,539 | A |
| Contingency Reserves Costs | $1,373 | B |
| Balancing Reserves Costs | $5,166 | C=A-B |
| | | |
| **Allocation of Hour Ahead Balancing Model Results** | | |
| Load | $2,235 | D |
| Wild Horse | $2,408 | E** |
| Third Party Generation | $523 | F |
| Total Balancing Reserves | $5,166 | Equals C |
| | | |
| **Balancing and Contingency Reserves Costs** | | |
| Contingency Reserves | $1,373 | Equals B |
| Load Balancing Reserves | $2,235 | Equals D |
| Balancing & Contingency Reserves | $3,608 | |

** reported as hour ahead wind integration

**Q. What is the third change to "Costs not in AURORA"?**

A. PSE added an adjustment to AURORA generated fuel costs to remove non-fuel startup costs of the simple cycle gas fired resources. AURORA considers startup costs in the unit commitment decision, and includes these costs in fuel cost of the simple cycle combustion turbines. This adjustment is necessary to remove these costs because they are O&M rather than power costs. This is a decrease of $261,367 to AURORA-generated power costs.

**Q. What forward market prices are used in determining the rate year power costs?**

A. Consistent with prior proceedings, PSE used the forward electric market prices generated by the AURORA hourly dispatch model. As discussed below, the three-month average gas prices at September 23, 2016, for the rate year, are input to the AURORA model.

## B. Power Cost Assumptions

### 1. Rate Year Power Supply Resources

**Q. Is PSE's rate year power supply portfolio for this proceeding different from the pro forma power cost portfolio approved in the 2014 PCORC?**

A. Yes. A number of changes to PSE's power supply portfolio have already occurred or will occur by or during the rate year. Specifically, the underlying portfolio used to determine PSE's rate year power costs for this proceeding reflect the following:

(i) the increase in forecasted quantity for the Electron PPA in the amount of [redacted] MWh;

(ii) the increase in contract rate effective December 1, 2017 associated with the Coal Transition PPA. The 2016 Power Cost Update that changed rates effective December 1, 2016 included the December 2016 capacity increase and contract rates as of December 2016. The rate year reflects [redacted] million of costs under the Coal Transition PPA in return for [redacted] million MWh (380 MW) of generation;

(iii) the expiration on February 29, 2016 of a power purchase agreement with Iberdrola Renewables for 100 MW of winter capacity associated with the Klamath peakers;

(iv) the expiration on June 30, 2017 of the WNP-3 Settlement Agreement with BPA that delivered up to 82 MW in November through February during heavy load hours and up to 41 MW during heavy load hours during the months March and April. In tandem with this expiration is the end of the Bonneville Exchange Power amortization which has reduced rate year power costs $3.5 million;

(v) the expiration on February 28, 2015, of a power purchase agreement with Barclays Bank PLC that delivered 75 MW of winter months' capacity;

(vi) the expiration on September 30, 2016 of a power purchase agreement with Hutchinson Hydro LLC for the output of 1 MW;

(vii) the renewal of a of a power purchase agreement with Douglas PUD for output from the Wells Hydroelectric Project effective September 1, 2018. Projected rate year power costs reflect an increase in PSE's allocation from 29.89 percent to an average of 32.07 percent in the last four months of the 2018 rate year. If the final contract differs from this assumption the capacity will be updated during this proceeding (please see Prefiled Direct Testimony of Michael Mullally, Exhibit No. __ (MM-1T), for the discussion on the renewal of the original Wells PPA);

(viii) an upgrade to the Goldendale plant that increased capacity to 300 MW (please see the Prefiled Direct Testimony of Ronald J. Roberts, Exhibit No. ___(RJR-1CT), for a description of this upgrade);

(ix) a scheduled upgrade to the Mint Farm that is expected to increase capacity to 314 MW (please see the Prefiled Direct Testimony of Ronald J. Roberts, Exhibit No. ___(RJR-1CT),for a description of this upgrade);

(x) updates to contracts executed under PSE's Schedule 91 Tariff, "Cogeneration and Small Power Production";

(xi) changes in the gas pipeline capacity and pipeline rates for the power book as discussed earlier;

(xii) new transmission contracts related to capacity increases at Mint Farm and Goldendale as discussed earlier; and

(xiii) updates to all rate year power contracts and resources to reflect current operations, contract terms and planned maintenance.

**Q. How did PSE treat its Colstrip resources in its rate year power costs?**

A. PSE has agreed to retire the boilers of Colstrip Units 1 & 2 no later than July 1, 2022, so they are assumed to be operational in the rate year, January – December 2018. Colstrip Units 3 & 4 are also assumed to be operational throughout the rate year.

### 2. Operating and Maintenance Costs of Gas-Fired Resources

**Q. Have the variable operating and maintenance costs used to model the dispatch of gas-fired resources changed since the 2014 PCORC?**

A. Yes, they have changed. In the 2014 PCORC only variable operating costs were used to model dispatch of the gas-fired resources in AURORA. This was consistent with actual operational dispatch decisions at the time.

Since then, PSE re-examined its O&M costs in an effort to better understand its costs and more closely align the information used for operational dispatch decisions with the true costs of operating its generating units. In this review process, PSE updated its estimates for variable O&M and major maintenance. PSE developed costs using industry definitions and three years of historical data for PSE's assets. The new estimates more accurately reflect the costs of operating PSE's gas fired generation and align with industry standards.

**Q. What costs are included in the new estimates of variable O&M costs?**

A. Variable operations costs pertain to demineralizer, heat recovery system generator, emissions, makeup water treatment chemicals and consumables supporting plant operations. Variable maintenance costs consist of corrective maintenance work that impacts the reliability and availability of the plant.

**Q. Did PSE also review its major maintenance costs?**

A. Yes, PSE also reviewed its major maintenance costs. Specifically, PSE reviewed three years of historical major maintenance data for its plants to develop cost estimates. For Goldendale and Mint Farm, Long Term Service Agreements with service providers establish major maintenance events based on run hours and number of starts, and the cost estimates are based on these Long Term Service Agreements. Major maintenance is expressed as a Major Maintenance Adder.

**Q. Are major maintenance costs influenced by PSE's dispatch of its generating units?**

A. Yes, the timing, frequency, and magnitude of major maintenance events are all influenced by a resource's run time. Operationally these events are considered in PSE's daily dispatch decisions, and therefore they need to be included in the modeling of dispatch decisions for projecting power costs. For projecting power costs in this proceeding, major maintenance costs for simple cycle combustion turbines were modeled on a cost per start basis. For combined cycle combustion turbines, major maintenance costs were developed on a cost per hour of run time basis and modeled in AURORA on cost per MWh basis.

**Q. How do PSE's cost estimates compare with industry cost estimates?**

A. CAISO provides estimates of variable O&M for EIM participants, and PSE compared its estimates using CAISO definitions with the CAISO estimates. This comparison confirms that PSE's estimates are reasonable. See Table 16 below for this comparison.

**Q. Which variable O&M costs did PSE use to model the dispatch of gas-fired resources in this proceeding?**

A. With one exception, PSE uses variable O&M costs established by CAISO to model dispatch of these resources. PSE's estimate of variable O&M for the Encogen combined cycle plant is higher than the CAISO estimate, therefore PSE uses its own calculated cost. Use of these costs is consistent with PSE operations.

**Q. Please summarize the updated costs estimates and those used in the 2014 PCORC.**

A. Variable O&M costs used in the 2014 PCORC and this proceeding are summarized in Table 16 along with CAISO variable O&M costs. Major maintenance costs used in this proceeding are also provided.

**Table 16**
**Variable O&M and Major Maintenance Costs of Gas-Fired Resources**

| Resource | 2014 PCORC Variable Operating Costs ($/MWh) | PSE Calculated Variable O&M ($/MWh) | CAISO Variable O&M ($/MWh) | 2017 GRC Variable O&M ($/MWh) | 2017 GRC Major Maintenance |
|---|---|---|---|---|---|
| **Combined-Cycle Combustion Turbines** | | | | | |
| Encogen | $0.96 | $[redacted] | $2.80 | $[redacted] | $[redacted] / MWh |
| Sumas | $0.37 | $[redacted] | $2.80 | $2.80 | $[redacted] / MWh |
| Ferndale | $0.60 | [redacted] | $2.80 | $2.80 | $[redacted] / MWh |
| Mint Farm | $0.22 | $[redacted] | $2.80 | $2.80 | $[redacted] / MWh |
| Goldendale | $1.45 | $[redacted] | $2.80 | $2.80 | $[redacted] / MWh |
| **Simple-Cycle Combustion Turbines** | | | | | |
| Whitehorn 2&3 | $0.07 | $[redacted] | $4.80 | $4.80 | $[redacted] / start |
| Frederickson 1&2 | $0.01 | $[redacted] | $4.80 | $4.80 | $[redacted] / start |
| Fredonia 1&2 | $0.09 | $[redacted] | $4.80 | $4.80 | $[redacted] / start |
| Fredonia 3&4 | $0.32 | $[redacted] | $4.80 | $4.80 | $[redacted] / start |
| Frederickson 1 combined cycle variable O&M of $[redacted]/MWh is based on PSE's contract with the majority owner, Atlantic Power. | | | | | |

**Q. Are the variable O&M and major maintenance costs included in power costs?**

A. No. As discussed earlier, power costs include only fuel, purchased power and third party transmission, not O&M. Production O&M costs are presented in the Prefiled Direct Testimony of Ronald J. Roberts, Exhibit No. ___(RJR-1CT), and included elsewhere in the revenue requirement presented in the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ___(KJB-1T). The O&M costs influence power costs because AURORA considers O&M in deciding when to run PSE's units and when to purchase power on the market.

### <u>3. Projected Hydro Availability</u>

**Q. What historical streamflow record has PSE used in its net power cost projection in this proceeding?**

A. PSE has used the average of the 80-year Mid-C streamflow history from 1929 through 2008 to project power costs for the rate year. In PSE's 2014 PCORC, 2013 PCORC and 2011 GRC PSE used 70-year Mid-C streamflow history from 1929 through 1998. PSE changed to 80-year data in consideration of the 2009 GRC Order, which noted that future rate cases should include more recent hydro data,[11] It is of interest to note that the Commission stated in the 2009 GRC Order:

> Inasmuch as the Company has access to at least some of the more recent data, its power cost evidence in future rate proceedings should include consideration of that data. . . .
>
> . . . . However, we have stated above our preference for using the longest span of years possible.

To be consistent with the Mid-C historical data, PSE used the same 80-year historical west side streamflow records for projections related to PSE's owned hydropower on the west side of the Cascade Mountains.

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[11] *See WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 at ¶ 124 (Apr. 2, 2010) (the "2009 GRC Final Order").

**Q. How does hydro generation affect projected rate year power costs?**

A. The 80 years of hydro generation is input into the AURORA model. The AURORA model relies on factors such as supply resources and regional load demand for power and transmission to simulate competitive wholesale power markets in which the regional fleet of generating resources is dispatched to meet regional electric loads. AURORA develops 80 results—one for each of the 80 hydro years. Rate year hydro generation is the average of hydro generation from these 80 model runs, and AURORA model normalized power costs are the average power costs from the 80 model runs.

### <u>4. Natural Gas Prices</u>

**Q. What natural gas prices did PSE use for the rate year in running its AURORA hourly dispatch model?**

A. As the Commission noted in its final order in Dockets UE-060266 and UG-060267 (the "2006 GRC"), the update for gas costs is "well-established" and should be "straightforward, mechanical and non-controversial."[12] Consistent with this order and all rate cases since, PSE used a three-month average of daily forward market prices for the rate year for each trading day in the three-month period ending September 23, 2016. PSE input these data into the AURORA hourly dispatch model for each month of the rate year.

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[12] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-060266 and UG-060267, Order No. 08 at ¶104 (Jan. 5, 2007).

In addition, consistent with prior general rate cases, all previously executed rate year short term power and gas for power contracts at the price cut-off date, September 23, 2016, are included in the rate year power costs. Fixed-price short term rate year power contracts are included within the AURORA hourly dispatch model and fixed-price rate year contracts for natural gas for its power portfolio are adjusted outside of the AURORA hourly dispatch model in the "Costs not in AURORA" calculations. An adjustment is also included in the "Costs not in AURORA" calculation for premiums and discounts associated with any power and gas for power contracts priced at plus or minus index. These contracts require updating whenever natural gas prices are changed or updated during a proceeding.

**Q. Please explain the fixed-price contracts mark-to-market adjustment.**

A. The gas price input to the AURORA hourly dispatch model represents a three-month average of the forecast market rate year gas prices at a certain point in time (in this case, September 23, 2016). Given PSE's hedging protocol, which includes a programmatic component that requires a specified amount of hedging be done each month, rate year power costs must reflect PSE's actual fixed price gas for power and power rate year contracts as of that date. Hedges are included because forecast rate year power costs consist of two components: (i) costs related to actual commitments; and (ii) forecast market costs dependent upon the AURORA modeled operational and market fluctuations. The adjustment requires calculating the difference between the three-month average monthly cost of natural gas at the pricing cut-off date (September 23, 2016, in this proceeding) and the monthly average cost of natural gas hedges transacted for the rate year as of the same cut-off date.

For each month of the rate year, this difference is multiplied by the volume of the gas for power hedges transacted for the rate year. The resulting amount represents the "mark-to-market" that is included in the power cost forecast. Including the fixed-price power contracts within the AURORA hourly dispatch model and marking both the fixed-price gas for power and index-based power and gas for power contracts to the three-month average rate year gas price input in the "Costs not in AURORA" calculation is consistent with the methodology used by PSE in determining rate year power costs since the 2006 GRC. This adjustment ensures that the cost included in rates represents what PSE expects to pay for those contracts PSE has already entered into.

**Q. How do projected gas prices inputs into AURORA for this proceeding compare with those in the 2014 PCORC and the 2016 Power Cost Update?**

A. Use of a single price can be misleading because there are different projected gas prices for each month of the rate year and for the different trading hubs from which PSE purchases gas. Additionally, these prices do not consider the impact of the fixed price gas contracts at the price cut off date, which may significantly change the average gas price. For purposes of comparison, however, the average forward gas price at the Sumas trading hub for the rate year is $2.70 per million British thermal units ("MMBtu") (for the three months ended September 23, 2016), which is $0.06 per MMBtu lower than the average $2.76 per MMBtu price included in the 2016 Power Cost Update, which was the basis for rates effective

December 1, 2016. The average gas price reflected in the 2014 PCORC settlement was $3.86 per MMBtu (for the three months ended October 28, 2014). Table 17 below presents average rate year gas price comparisons.

**Table 17. Average Annual Rate Year Gas Prices**

| **Rate Case =>** | **2017 GRC** | **2016 Power Cost Update** | **2014 PCORC** | **2013 PCORC** |
|---|---|---|---|---|
| 3-Mo Average at => | 9.23.16 | 8.26.16 | 10.28.14 | 8.05.13 |
| Rate Year | Jan 2018– Dec 2018 | Dec 2016- Nov 2017 | Dec 2014– Nov 2015 | Nov 2013– Oct 2014 |
| Sumas | $2.70 | $2.76 | $3.86 | $3.99 |
| Change from Prior | $(0.06) | $(1.10) | $(0.13) | $1.09 |

**Q. Please explain the source of the gas price inputs.**

A. Consistent with prior rate cases, PSE has used forward gas market price data supplied by Kiodex Global Market Data ("Kiodex"). PSE contracts with Kiodex for forward market price data for specific gas and power trading points and for the trading hubs that are input into AURORA.

Kiodex, however, does not offer forward price curves for the Station 2 hub located in British Columbia. Although this price hub is not a trading hub required for input to AURORA, PSE has T-south pipeline capacity between Station 2 and Sumas under contract with Westcoast Energy, Inc. Since the AURORA model uses the input Sumas gas prices for PSE's gas fired generators' dispatch and power costs, PSE must separately consider the cost difference between Station 2 and Sumas, also known as the "basis differential", in the "Costs not in AURORA" adjustments.

Since there is no readily available forward gas price for Station 2, PSE has contracted with a third party (Wood Mackenzie) to provide an independent forward price forecast of the basis differential between the Sumas and Station 2 gas hubs. Because Sumas is one of the gas hubs acquired from Kiodex for input to AURORA, PSE calculates the monthly Station 2 forward gas prices for the rate year by adding the Kiodex Sumas forward gas price to the Wood Mackenzie basis differential. In this regard, all gas prices used in the determination of rate year power costs are then based upon forward price curves and third party forecasts for the rate year period. PSE has used third party forecasts of price differentials to estimate Station 2 prices since the 2011 GRC.

**Q. Does PSE intend to update its projected power costs with updated gas price projections during this proceeding?**

A. Yes. Consistent with prior rate proceedings, PSE intends to update its projected power costs with updated gas price projections during the course of this proceeding because the factors that affect natural gas prices are constantly changing, forward market prices quickly become "stale," and their predictive power with respect to actual future prices decreases with time. Establishing rate year gas prices based on the average of the forward prices for the rate year for a three-month period of time closer to the beginning of the rate year will provide a more accurate projection of rate year gas prices. Therefore, PSE will adjust its requested power costs with updated forward market data prior to rates becoming effective. This would also include an update to the short-term fixed-price power contracts that are an AURORA input and the other fixed-price gas for power and index-based power and gas for power contracts that are an adjustment included in the "Costs not in AURORA" calculation. In addition, some "Costs not in AURORA" adjustments are dependent on AURORA output and will be updated when a new AURORA model run is completed.

**Q. What is PSE's proposal to update its projected rate year power costs during this proceeding?**

A. PSE intends to provide all parties with updated power cost information—including, but not limited to, updated average gas prices—during the course of the proceeding, in a manner and at a date that enables all parties adequate time to review the proposed changes.

**Q. How do more recent forecast rate year natural gas prices compare to the three-month average at September 23, 2016?**

A. As of November 30, 2016, the three-month average rate year Sumas natural gas price has decreased to $2.61per MMBtu, a decrease of $0.09 per MMBtu from the $2.70 per MMBtu used to determine the prefiled rate year power costs in this proceeding.

### 5. Projected Wind Generation

**Q. What projection of wind generation did PSE use for the rate year in developing its power costs?**

A. In 2016 PSE retained Vaisala, a global company that specializes in environmental and industrial measurement, to develop a forecast of energy output from its wind resources. PSE used the long-term forecast produced by Vaisala for each of its plants to project power costs of wind generation in this proceeding.

**Q. Why did PSE update its wind forecast?**

A. Preconstruction forecasts were developed for each of the facilities, and in 2010 PSE retained DNV to update those forecasts. These DNV forecasts were used in the 2014 PCORC. Several years have passed since the forecasts were developed, and at this time, there is more historical data available to inform a new forecast: ten years of data for Hopkins Ridge and Wild Horse, six years for Wild Horse Expansion, and four years for Lower Snake River. A new forecast provides a better, more up-to-date estimate of output from the facilities.

**Q. How does the Vaisala forecast compare to the previous forecast?**

A. On average, for all of PSE's facilities together, the annual energy projection is 99,000 MWh, or 4.8 percent, below the level in the old forecast.

**Q. Did PSE update the forecasted generation from the Klondike Power Purchase Agreement also?**

A. PSE requested and received a forecast of PSE' share of the output of Klondike from Klondike Wind Power. The annual energy projection for Klondike is 28,000 MWh, or 17.5 percent, below the level in the old forecast.

### 6. Load Forecast

**Q. What load forecast did PSE use for the rate year in running its AURORA hourly dispatch model?**

A. PSE used the most current electric load forecast—the F2016 load forecast—as the rate year demand input to the AURORA model. The delivered electric load forecast, net of demand-side resources (conservation), for the January 1 through December 31, 2018, rate year is 23,272,547 MWh, or 2,657 average megawatts ("aMW"). This is an increase of 340,034 MWh, or 1.5 percent from the 2014 PCORC load forecast of 22,932,513 MWhs, or 2,618 aMW. The 2014 PCORC power cost forecast used the then-current load forecast, the F2013 load forecast, for the 2014 PCORC rate year December 1, 2014 through November 30, 2015. The difference in demand between the two periods is due to customer growth, use per customer changes as a result of conservation, and differences in projected regional economic growth between the F2016 and F2013 load forecasts.

The upcoming 2017 IRP will be based on the same F2016 load forecast used to project power costs in this proceeding.

**Q. What load forecast was used for the analysis underlying the BPA transmission contract renewals and additions?**

A. The analyses of the 23 MW Vantage transmission contract and the 94 MW Garrison transmission contract were based on the F2014 load forecast, which was the current forecast at the time both analyses were completed, February and September 2015, respectively.

### 7. Clean Air Rule

**Q. What input assumptions related to CAR were used to project rate year power costs?**

A. As indicated earlier, PSE estimated emissions limits for its combined cycle plants based on the methodology described in the rule and historical emissions data. These estimated emissions limits were placed on the combined cycle units in AURORA. Historical emissions for the 2012-2015 period[13] and the estimated caps for PSE's combined cycle units are presented in Exhibit No. ___(PKW-5).

**Q. Are other generating plants in Washington also expected to be impacted by CAR?**

A. Yes. The Department of Ecology's historical emissions data indicates that Gray's Harbor Energy Center, Chehalis Generating Facility, River Road Generating Plant, and March Point are all likely to be subject to limits in 2018. To project PSE's rate year power costs, PSE models the entire Western Electricity Coordinating Council, therefore it was necessary to include estimated CAR emission limits for these plants in the analysis. PSE estimated emissions caps for these units based on 2012-2015 historical data provided by the Department of

[13] Data for 2016 are not yet available.

Ecology and included these caps in AURORA. This historical data and the estimated caps are also included in Exhibit No. ___(PKW-5).

## X. COMPARISON OF PROJECTED POWER COSTS TO THE PROJECTED POWER COSTS CURRENTLY IN RATES

**Q. How do the power cost projections in this proceeding compare with the power cost projections approved in the 2016 Power Cost Update?**

A. The power cost projection in this case is approximately $31.2 million higher than the power costs projections approved in the 2016 Power Cost Update that established rates effective December 1, 2016. However, the proposed power costs are slightly lower than the total power costs included in the 2014 PCORC settlement, which were in rates through November 30, 2016. The 2014 PCORC settlement included power costs of $752.3 million. Please see Exhibit No. ___(PKW-4C) for a resource by resource comparison of the projected power costs and generation for the 2016 Power Cost Update rate year (December 1, 2016, through November 30, 2017) and the projected power costs for the rate year in this proceeding (January 1, 2018 through December 31, 2018).

**Q. What are the causes of the change in projected power costs relative to the 2016 Power Cost Update?**

A. The following items caused the majority of the change to projected rate year power costs from the 2016 Power Cost Update:

(i) increased costs due to compliance with the Clean Air Rule;

(ii) increased costs due to lower wind and hydro generation forecasts;

(iii) increased gas pipeline costs;

(iv) increased costs due to a 1.5 percent increase in forecast load;

(v) increased BPA transmission costs due to tariffs effective October 1, 2015 as discussed above, and new contracts;

(vi) added costs related to balancing and contingency reserve obligations, and

(vii) updates for new, existing and expiring purchase power agreements.

**Q. What impact did CAR have on rate year power costs?**

A. Limiting use of PSE's gas fired generating resources based on estimated emissions limits imposed by CAR resulted in an increase of $18.5 million to rate year power costs.

**Q. How did PSE calculate this projection of $18.5 million?**

A. PSE first completed its projection of power costs without CAR emissions limits. PSE then added the estimated limits to resources in Washington as discussed earlier and completed the analysis again. The difference between the power costs projections with and without CAR limits, with every other input unchanged, was $18.5 million. This difference includes both costs in AURORA and a few costs not in AURORA that changed with the inclusion of CAR because they are dependent on projected market prices, which are different with and without CAR. Exhibit No. ___(PKW-6C) presents the change in costs related to CAR.

**Q. Why does CAR result in a projected $18.5 million increase to power costs?**

A. Limiting the operation of the portfolio's most efficient gas fired generation resources creates a need to run other higher cost gas fired generation resources and to purchase power from the market.

**Q. In the analysis, how do the emissions from PSE's combined cycles units compare with their estimated caps?**

A. In total, emissions are below the collective PSE cap by 136,411 metric tons of CO2e, or 7.8 percent. Three units are slightly above their individual caps and three units are below their caps.

## XI. STATUS OF WHITE RIVER SURPLUS PROPERTIES

**Q. Please explain the most recent regulatory order related to PSE's disposition of its White River properties.**

A. When PSE discontinued operations of the White River Hydroelectric Project in 2004, PSE pursued efforts to maximize the value of the White River properties in order to offset the value of the stranded investment. PSE was able to sell certain of the properties and its water rights to the Cascade Water Alliance ("CWA"). However, PSE had remaining project assets ("Surplus Properties") that it was not able to sell.

At the time the CWA transaction was complete, PSE filed a petition under Docket UE-090399 to dispose of the CWA properties as well as to waive the requirements of RCW 80.12.020 and WAC 480-143-120 to obtain approval for disposal of the Surplus Properties (the "2009 Application"). In the final order in that docket, the Commission determined that PSE could dispose of the CWA properties, but denied its petition to waive the requirements of RCW 80.12.020 and WAC 480-143-120 for the Surplus Properties.

Additionally, the order required PSE to continue to defer the total net costs, including the CWA proceeds and any other proceeds for Surplus Properties, in the regulatory asset and to bring the issue of the application of such proceeds to the Commission for consideration in the general rate case following the full disposition of the Surplus Properties.

Please see the Prefiled Direct Testimony of Ms. Katherine J. Barnard, Exhibit No. ___(KJB-1T), for a discussion regarding the regulatory background of the White River properties.

**Q. Has the Commission made a determination related to PSE's sale of the White River assets to the Cascade Water Alliance?**

A. Yes. In Paragraph 344 in Order 11 in PSE's 2009 general rate case, Docket UE-090704, the Commission determined that PSE's sale of the White River assets to the Cascade Water Alliance was reasonable and appropriate. Therefore, the focus of my testimony is to discuss the current status of the Surplus Properties.

**Q. In the 2009 general rate case, you testified about a potential sale of the Surplus Properties to the Muckleshoot Tribe. Please explain what has transpired since that case.**

A. In 2006 and 2007 the Muckleshoot Tribe had expressed interest in purchasing the Surplus Properties. PSE engaged the Cascade Land Conservancy (now Forterra) to access their expertise in conservation-related land transactions. PSE asked Forterra to develop a transaction disposing of the Surplus Properties. At that time, PSE estimated the property value at $14.4 million. Forterra initiated discussions with the Muckleshoot Tribe regarding the sale of the properties but was unable to obtain a price close to the estimated value. PSE determined it could obtain more value from the properties if marketed and sold individually, and PSE was actually able to do so. Based on this, PSE declined the offer from the Muckleshoot Tribe.

**Q. Has PSE exhausted all options for disposal of the Surplus Properties?**

A. Yes. As described below, PSE has sold all of the properties it can and has current or future needs for the remaining properties.

**Q. Please provide a background of the efforts PSE engaged in to dispose of the Surplus Properties.**

A. In an effort to economically dispose of the Surplus Properties, PSE grouped the Surplus Properties into four main categories based on their characteristics:

- Properties that could be marketed and sold;
- Properties that PSE should retain for utility operations or facilities use;
- Properties that would require significant investment to remediate for environmental reasons if sold; and
- Properties that can be used in the future as habitat mitigation for other PSE projects such as PSE's current Eastside 230 project.

**Q. Please describe what PSE did with the properties that had a chance of being marketed and sold.**

A. PSE determined that the best way to dispose of the marketable properties was to offer them in an auction. PSE listed these Surplus Properties in the Fall 2014 Auction sponsored by Realty Marketing/Northwest ("RM/NW"). During this auction, PSE received multiple bids on some of its properties, and completed sales to the highest bidders. PSE again prepared to list some of the remaining marketable properties in the Fall 2015 RM/NW Auction, and in preparation of the listings RM/NW personnel contacted neighboring property owners to gauge interest and notify them of a potential sale, and PSE and RM/NW were able to negotiate sales with these parties prior to the auction.

**Q. Since the 2009 Application, what was the total amount of net proceeds received for these properties and how were they recorded?**

A. PSE received net proceeds of $2.8 million for the Surplus Properties sold and incurred $2.4 million of costs related to achieving these sales, as well as maintaining and preparing the properties for sale. This results in total net proceeds of $0.3 million since the 2009 Application. In accordance with the Commission's orders in Dockets UE-030243 and UE-090399, PSE deferred these net proceeds in the regulatory asset in FERC 182.3 for White River where they will be held pending the Commission's decision in this proceeding. Please see Exhibit No. ___(PKW-7) for a listing of Surplus Properties that PSE sold.

The sale prices of all of the Surplus Properties that have been sold were under the limit that requires specific approval under WAC 480-143-180.

**Q. Please describe the properties that PSE plans to keep for system use.**

A. There are multiple properties that are being utilized by PSE as part of its operating utility system. The properties are utilized by PSE for electric transmission lines, substations, communication facilities and electric distribution lines. Several of the PSE owned properties are burdened with easements in favor of others for the transport of natural gas (Williams gas pipeline) and electric transmission (Bonneville Power Administration). These properties also include the Lake Tapps conference facilities. Please see Exhibit No. ___(PKW-7) for a listing of Surplus Properties that PSE plans to retain for system use.

**Q. Are there any additional costs and proceeds related to the Surplus Properties that will be included in the regulatory asset?**

A. Yes. PSE entered into a contract with North Wind Forest Consultants to advise and assist with the required permitting, timber sale, and re-forestation of a 96 acre property in Pierce County. The property is currently utilized by PSE for electric transmission lines and related infrastructure.

North Wind Consultants secured the required permits to allow the logging to proceed. Thereafter and upon issuance of the required permits, North Wind solicited bids from its list of logging industry contacts interested in purchasing standing timber such as that presently growing on the PSE property. Upon receipt and review of multiple bids received, PSE in consideration of advice from North

Wind, chose the highest bidder for the sale of the standing timber. The winning bid of $[redacted] is within the range of North Wind's anticipated bid values and is consistent with PSE's previous timber valuation for the property. PSE accepted the bid. PSE expects to be paid in full for the value of the timber contract within 30 days of contract finalization with the successful bidder. In the meantime, PSE holds a $[redacted] potentially non-refundable deposit submitted by the winning bidder which will be relinquished to PSE if that bidder does not finalize the logging contract. PSE will recoup selling costs from the winning bid.

The successful bidder will then have twelve months to remove the timber from the property. PSE will re-forest, establish and maintain a new stand of timber following the logging of the site. At this time, it is expected that PSE will finalize the logging contract with a successful bidder by early 2017. The costs and proceeds related to this logging contract will be included in the regulatory asset and this is discussed in more detail in the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ___(KJB-1T).

**Q. Please describe the properties that would require significant investment to remediate for environmental reasons if sold.**

A. Certain properties were originally included in the properties that PSE negotiated with CWA to purchase. However, during negotiations, CWA determined that because of the contamination of these properties, it was not willing to purchase these properties as part of the CWA transaction. Accordingly, these contaminated properties remain under PSE ownership and are not marketable to third parties.

The remediation costs that would be required to achieve marketability of these properties would exceed the expected property sales values after remediation; therefore, it is more economical to retain these properties. Please see Exhibit No. ___(PKW-7) for a listing of properties that are not marketable to third parties.

**Q. Please describe the Surplus Properties that may be useful in the future as habitat mitigation.**

A. There are properties in a riparian corridor that are not directly related to environmental remediation but that may benefit PSE customers by reducing mitigation costs of certain projects. Often a significant requirement of construction projects is mitigation to offset impacts to flora and fauna in the rights of way. Through the continued ownership of this riparian corridor, PSE is afforded a cost effective means of offsetting those mitigation requirements. Please see the Prefiled Direct Testimony of Katherine J, Barnard, Exhibit No. ___(KJB-1T), for a summary of PSE's request related to the White River properties in this proceeding.

## XII. CONCLUSION

**Q. Please summarize your testimony.**

A. PSE actively manages the power and gas cost risks faced by its customers in order to keep power costs as low as reasonably possible. PSE's $745.3 million projected rate year power costs for this proceeding are consistent with, and based on, sound assumptions using methodologies approved by the Commission in PSE's prior general and power cost only rate cases.

**Q. Does that conclude your prefiled direct testimony?**

A. Yes, it does.