EXHIBIT NO. ___(DEM-1CT)
DOCKET NO. UE-14____
2014 PSE PCORC
WITNESS: DAVID E. MILLS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-14____**

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF DAVID E. MILLS ON BEHALF OF PUGET SOUND ENERGY, INC.

PUBLIC VERSION

MAY 23, 2014

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
DAVID E. MILLS

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

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

A. My name is David E. Mills. My business address is 10885 NE Fourth Street, P.O. Box 97034, Bellevue, WA 98009-9734. I am the Vice President, Energy Supply Operations for Puget Sound Energy, Inc. ("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. ___(DEM-2).

Q. What are your duties as Vice President, Energy Supply Operations at PSE?

A. As Vice President, Energy Supply Operations, my responsibilities include oversight of PSE's Power and Gas Supply Operations, Load Serving Operations, Transmission Contracts, and Energy Supply Operations Policy, Planning & Compliance groups. My responsibilities include management of PSE's short- and medium-term wholesale power and natural gas portfolios (up to three years) and involvement with planning for long-term hedging requirements in addition to

PSE's transmission functions as they pertain to the Load Office and Balancing Authority Area operations.

Q. What has prompted PSE to file a power cost only rate case at this time?

A. In Order 08 in Docket No. UE-121373, the Commission required PSE to file a 2014 power cost only rate case ("PCORC") to recover the costs of the purchased power agreement with TransAlta Centralia Generation LLC ("Coal Transition PPA") that begins December 1, 2014. In that order, the Commission stated as follows:

> We determine that PSE should be authorized and required to file a PCORC timed so that the any incremental power costs created through this PPA beginning on December 1, 2014, can be recovered fully and timely in rates. Furthermore, we encourage PSE to propose in the context of its initial PCORC filing additional clarifications, such as the compliance filing approach suggested by Multiparty Settlement Agreement, and how this will interact with annual adjustments in the PCA baseline. Ideally, PSE will work with Commission Staff and the other interested parties to present to us a consensus approach providing for timely cost recovery of such incremental power costs throughout the term of this PPA.

WUTC v. Puget Sound Energy, Inc., Docket No. UE-121373, Order 08 at ¶ 53 (2013).

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

A. This prefiled direct testimony addresses the following issues relevant to both the PCORC and power costs for this proceeding's rate year December 1, 2014 through November 30, 2015 (the "rate year"):

(i) PSE's requested rate change;

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

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

(iv) the impact of the Bonneville Power Administration's ("BPA") upcoming rate proceeding and renewal of BPA transmission contracts;

(v) the renewal of the purchased power agreement with Powerex to serve Point Roberts, Washington (the "Point Roberts PPA")

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

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

(viii) an introduction to the other witnesses in the case and the topics they will address in their prefiled direct testimony.

PSE's power cost projections for the rate year are higher—$17.4 million,[2] or 2.4 percent higher—than power cost projections currently in PSE's rates. The overarching reason for the increase in projected power costs from those currently set in rates is the inclusion of the Coal Transition PPA in PSE's portfolio.

There are several other power cost changes that nearly offset. For example, power costs increases due to higher load, increased coal costs, higher transmission expenses, increased market prices and wind integration expenses were more than offset by cost decreases due to higher hydroelectric generation, lower gas

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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 and transmission capacity.

[2] The $17.4 million increase differs from the $15.7 million increase on line 46 of Exhibit No. ___(KJB-7) due to the reclassification of employee benefits and taxes, the application of production and conversion factors, as well as the revenue requirement calculation on a unit cost basis.

transportation costs, expiring long-term power contracts, and the benefit of short-term, fixed-priced contracts.

II. REQUESTED RATE CHANGE

Q. What level of rate change is PSE requesting in this case?

A. PSE is proposing to decrease rates for electric customers by $9.6 million, an average 0.46 percent decrease from the electric power cost adjustment mechanism ("PCA") rates set in PSE's 2013 power cost only rate case, Docket No. UE-130617 (the "2013 PCORC"), that became effective on November 1, 2013. Please see Prefiled Direct Testimony of Ms. Katherine J. Barnard, Exhibit No. ___(KJB-1T).

Q. Please explain why PSE is proposing a decrease in this proceeding.

A. PSE's current electric rates include all production-related costs to provide the power needed to serve its electric customers for the 2013 PCORC rate year (November 1, 2013 through October 31, 2014). Since those costs were determined, changes have occurred or will occur with respect to PSE's electric portfolio that, in total, are projected to decrease PSE's revenue requirement during the rate year for this case. These changes are discussed in my testimony below and in the testimonies of several witnesses I will introduce in my testimony.

Q. Is PSE requesting any other determinations in this proceeding?

A. Yes. PSE seeks a prudence determination in this proceeding with respect to (i) PSE's transmission contract renewals with BPA and (ii) the renewal of the Point Roberts PPA.

Additionally, PSE is presenting and requesting approval of its methodology for providing for timely cost recovery of the incremental power costs and equity adder associated with the Coal Transition PPA. See generally the Prefiled Direct Testimony of Ms. Katherine J. Barnard, Exhibit No. ___(KJB-1T).

Finally, PSE is presenting and requesting approval of the additional capital costs associated with the Snoqualmie Falls and Baker River Hydroelectric Project upgrades that were incurred in excess of the amounts approved in the 2013 PCORC. See generally the Prefiled Direct Testimony of Mr. Douglas S. Loreen, Exhibit No. ___(DSL-1T).

III. VOLATILITY AND RISK IN PSE'S ELECTRIC RESOURCE PORTFOLIO

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

A. A key responsibility of PSE is to provide safe and reliable electric service at a reasonable cost to its customers. To ensure PSE customers receive the power they need, PSE manages a complex power portfolio during every hour of every day, relying on the region's power markets to supply additional electricity to balance customer demand with PSE's available power resources. 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, nearly 20 percent of PSE's electric energy production is from 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/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 2,623 megawatts ("MW") of thermal generating units to help meet its customer loads.

Table 1. PSE's Thermal Generation Units

	Capacity (MW)
Coal	658
Goldendale	262
Mint Farm	289
Ferndale	273
Frederickson 1/Atlantic Power	134
Encogen	162
Sumas	132
Non-Utility Generators	100
Simple Cycle Combustion Turbines	613
Total MWs	**2,623**

The capacities shown above 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) 1,352 MW of gas-fired, combined-cycle combustion turbines with moderate heat rate conversions; and

(iii) 613 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 approximately 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-Columbia ("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, Generation and Capacity Factor

	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**	2,195,964	

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,[3] and forced outages. For example, if power cannot be wheeled[4] from the Mid-C trading hub to PSE's system, PSE would be forced to meet load by dispatching other

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

4 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.

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

IV. 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 highly 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;
- selection of specific commodities to be hedged as informed by Margin at Risk analyses;
- 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 strategies since the 2013 PCORC?

A. No. PSE's hedging strategy is unchanged since the 2013 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 have been transacted as of April 10, 2014 for delivery during the rate year.

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 2014 PCORC Rate Year
Short-Term Fixed Price Power Portfolio Hedges
at April 10, 2014

	MWh Volume	Rate Year Cost	Avg $/MWh
On-Peak Power Purchases	1,973,200	$74,794,400	$37.91
Off-Peak Power Purchases	1,316,000	$34,913,809	$26.53
Total Power Purchases	3,289,200	$109,708,209	$33.35
On-Peak Power Sales	(20,800)	(1,063,400)	$51.13
Off-Peak Power Sales	–	–	–
Total Power Sales	(20,800)	(1,063,400)	$51.13
Net Power Fixed	3,268,400	$108,644,809	

	Dth Volume	Rate Year Cost	Avg $/Dth
Net Financial Gas for Power (Dth)	17,630,000	$76,092,083	$4.32

As discussed below, to determine rate year power costs, the fixed-price gas for power contracts are marked to market in the "Not in Models" calculation and the fixed-price power contracts are included within the AURORA model.[5] 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 "Not in Models" calculation.

[5] The AURORA model is discussed in Section VIII. A., Overview of Projected Power Costs for this Proceeding.

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 index swaps[6] 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 index swap, in combination with a physical index purchase, result in a price position identical to purchasing fixed price physical supply.

PSE is enabled 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.

V. BPA'S 2016-2017 RATE CASE

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

A. Yes. In November 2014, BPA will begin a combined power and transmission rate proceeding to set new rates for BPA's fiscal years 2016-2017 (October 1, 2015 through September 30, 2016) (the "BPA 2016 Rate Case"). BPA has projected a

[6] Fixed-for-float index 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.

transmission rate increase on its Network segment of 9.7 percent, effective October 1, 2015

Q. Will PSE participate in the BPA 2016 Rate Case?

A. Yes. PSE will intervene in the BPA 2016 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 BPA's projected transmission rate increase of 9.7 percent, effective October 1, 2015, in the pro forma transmission costs included in the rate year power cost forecast. These BPA proposed rate increases have added $1.7 million to PSE's rate year power costs. The projected rate increase to be proposed by BPA in the BPA 2016 Rate Case may change during the course of this proceeding, and PSE requests permission to update rate year power costs to reflect any such changes.

VI. TRANSMISSION CONTRACT RENEWALS

Q. Please provide an overview of the transmission contracts renewed since the conclusion of the 2013 PCORC.

A. PSE uses transmission to wheel 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 provide power continuously during a peak capacity 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 2013 Integrated Resource Plan ("2013 IRP").[7] These transmission contracts are an integral part of PSE's electric resource portfolio and are necessary to provide capacity and energy to customers. PSE has renewed several transmission contracts with BPA to be used to access these short-term market purchases at Mid-C. PSE has not entered into new BPA transmission contracts since the 2013 PCORC.

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[7] *See* Puget Sound Energy, Inc., *2013 Integrated Resource Plan*, Chapter 5 (Electric Analysis) (May 30, 2013), available at http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_Chapters.pdf.

Q. Do you have a summary of PSE's transmission renewals and additions for the rate year?

A. Yes. Table 4 below shows a summary of the transmission contracts with BPA that have or will expire before the end of the rate year.

Table 4. BPA Transmission Contract Renewals

Resource	Renewal Deadline	Start Date	Megawatt Capacity
Mid-C—various contracts	10/31/13	11/1/14	305
Mid-C	11/30/13	12/1/14	169
Total Mid-C Cross-Cascades Firm Transmission Renewals			**474**
Frederickson 1	2/28/14	3/1/15	137
Total Transmission Renewed for Resources and Load			**137**

A. Mid-C Cross-Cascades Firm Transmission Renewals

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

A. PSE relies on existing firm BPA transmission contracts from Mid-C to PSE's system as short-term resources to meet customers' capacity needs. PSE uses this type of transmission to move its share of Mid-C hydro generation and short-term market purchases from the Mid-C hub to serve PSE's load. These short-term market purchases, combined with the transmission, are referred to as "Available Mid-C Transmission" in PSE's 2013 IRP process. As Mid-C transmission contracts become eligible for renewal, PSE evaluates the costs and risks of Mid-C resources, drawing on information from PSE's 2013 IRP.

Q. What information does PSE consider in making a decision to renew a transmission contract?

A. In considering whether to renew a transmission contract, PSE considers resource need, availability of regional surplus capacity, resource costs from its most recent request for proposals ("RFP") and 2013 IRP processes, and the likely availability of Mid-C transmission in the future.

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

A. PSE evaluates the costs and benefits of renewing its Mid-C transmission contracts in order to have adequate information to make a prudent decision by the renewal deadline. Table 5 below shows PSE's Mid-C renewal decision deadlines for 2013 and 2014 for contracts renewed subsequent to PSE's 2013 PCORC.

Table 5. BPA 2013 Mid-C Transmission Renewal Deadlines

Resource	Renewal Deadline	Start Date	Megawatt Capacity	Evaluation Decision
Mid-C—various contracts	10/31/13	11/1/14	305	Oct. 2013
Mid-C	11/30/13	12/1/14	169	Oct. 2013
Total			474	

Q. Please provide a summary description of the 305 MW and 169 MW Mid-C firm transmission renewals.

A. During 2013, PSE performed extensive analysis of Mid-C transmission renewals using the Portfolio Screening Model III, also known as the "Optimization Model", consistent with the 2011 RFP analysis. This analysis was also consistent with the analyses supporting the prudent transmission contract extensions approved in

PSE's 2013 PCORC. Please see the Prefiled Direct Testimony of Ms. Janet K. Phelps, Exhibit No. ___(JKP-1T), for a discussion of PSE's analyses of the 305 MW and 169 MW Mid-C firm transmission renewals.

Q. What are the terms of the BPA transmission renewals?

A. BPA's Open Access Transmission Tariff ("OATT") grants an ongoing right to transmission customers to renew or "rollover" contracts that have a minimum term of five years. A customer must provide notice of whether or not it will exercise its right of first refusal to renew the contract no less than one year prior to the expiration date of the transmission service agreement.

Rollover rights are very important to transmission contracts because the BPA system has become and continues to become more constrained. Retaining existing capacity on the BPA system helps ensure that PSE's customers can receive reliable service at a reasonable rate.

Q. Could PSE renew only a portion of the 305 MW and 169 MW Mid-C firm transmission contracts?

A. Yes. PSE has the option to renew all or any portion of the 305 MW and 169 MW Mid-C firm transmission contracts. 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.

PSE had the option to renew the 169 MW contract at 209 MW. PSE chose to renew at a lower capacity because the contract agreement would drop to 169 MW after the first year regardless of PSE's election to renew at 169 MW or 209 MW. PSE currently has a short-term surplus in Mid-C transmission; therefore it was not necessary to retain the 40 MW for a single year. Please see the Prefiled Direct Testimony of Ms. Janet K. Phelps, Exhibit No. ___(JKP-1T), for a discussion of the analysis regarding this renewal.

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 Network Open Season ("NOS") process. On April 30, 2013, BPA announced the completion of the 2013 NOS Cluster Study, which included nearly 4,000 MW of requests for transmission capacity, and will share the results of the 2013 NOS Cluster Study in late May 2014. Following the 2013 NOS Cluster Study, BPA will evaluate the economics of identified new projects and determine which will remain in the 2013 NOS process and move forward into environmental review.

A new Mid-C firm transmission request requires capacity on multiple constrained BPA flowgates. The most prominent BPA flowgate affecting a new Mid-C firm transmission request for PSE is the Cross-Cascades North flowgate. The Cross-Cascades North flowgate is highly constrained, with no available winter month capacity posted on the BPA website at the time of the decision to renew the contract for this Mid-C transmission. The BPA website currently shows transmission request queue information through April 2024.[8] The BPA posted capacity does not include current plans to upgrade the transmission system affecting the Cross-Cascades North flowgate; however, the additional capacity available after upgrade completion would not fulfill the current needs of the BPA transmission queue, and the projects could also be subject to delays.

Q. Did PSE present the Mid-C firm transmission renewal analysis to the Energy Management Committee ("EMC")?

A Yes. On October 17, 2013, PSE presented the Mid-C firm transmission renewal analysis to the EMC for approval. On November 20, 2013, PSE also presented an update regarding Mid-C firm transmission renewals to the EMC.

Q. Did PSE renew the 305 MW and 169 MW Mid-C firm transmission contracts with BPA?

A. Yes. PSE renewed the 305 MW and 169 MW Mid-C firm transmission contracts with BPA.

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[8] BPA maintains a ten-year inventory of available flowgate capacity ("AFC") less impacts of all pending queued requests on the transmission section of their website, available at http://www.bpa.gov/transmission/Reports/TransmissionAvailability/_layouts/download.aspx?SourceURL=Documents/atc_less_pending.xls. BPA's version of this document dated May 12, 2014, indicates that 2023 winter capacity (December) on the Cross Cascades North flowgate is negative (-) 1,158 MW, indicating there is significantly more transmission capacity requested than available capacity on the flowgate.

Q. Are PSE's renewals of the 305 MW and 169 MW Mid-C firm transmission contracts with BPA prudently incurred expenses?

A. Yes. PSE's renewals of the 305 MW and 169 MW Mid-C firm transmission contracts with BPA were prudently incurred expenses, as discussed above. PSE requests the Commission approve PSE's recovery of these contracts and recovery of the $10.0 million of rate year power costs associated with these 474 MW total Mid-C firm transmission contracts.

B. 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 a 137 MW firm transmission contract with BPA to allow continued delivery of power from the Frederickson 1 Generating Station.

Q. Please describe the 137 MW firm transmission contract with BPA to deliver power from the Frederickson 1 Generating Station.

A. The Frederickson 1 Generating Station is a jointly-owned, existing gas-fired generating facility currently serving PSE load. BPA wheels power from the Frederickson 1 Generating Station to PSE's system under a 137 MW firm transmission contract, which was scheduled to expire on February 28, 2015.

Q. Did PSE present the renewal analysis for the 137 MW firm transmission contract with BPA to deliver power from the Frederickson 1 Generating Station to the EMC?

A Yes. On February 20, 2014, PSE presented the 137 MW firm transmission renewal analysis for the Frederickson 1 Generating Station to the EMC.

Q. Did PSE renew the 137 MW firm transmission contract with BPA to deliver power from the Frederickson 1 Generating Station?

A. Yes. PSE renewed the 137 MW firm transmission contract with BPA for five years (until March 1, 2020) to allow continued delivery of power from the Frederickson 1 Generating Station.

Q. Is PSE's renewal of the 137 MW transmission contract with BPA to deliver power from the Frederickson 1 Generating Station a prudently incurred expense?

A. Yes. PSE's renewal of the 137 MW transmission contract with BPA to allow continued delivery of power from an existing PSE resource—the Frederickson 1 Generating Station—was a prudently incurred expense. PSE respectfully requests that the Commission approve PSE's recovery of this contract and recovery of the $2.2 million of rate year power costs associated with the transmission contract.

C. 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 long-term contracts in order to reliably deliver power to PSE's system to serve load. PSE respectfully requests the Commission deem these expenses to be prudently incurred and allow PSE to recover these costs in rates.

VII. POINT ROBERTS PPA RENEWAL

Q. Why does PSE need the Point Roberts PPA?

A. Point Roberts, Washington is part of Washington State but is not physically connected to the remainder of the United States. Instead, Point Roberts is located on the southernmost tip of the Tsawwassen Peninsula, south of British Columbia, Canada. To access Point Roberts by land, one must travel through British Columbia. Point Roberts may also be accessed from Washington State by crossing Boundary Bay by sea or air.

PSE is currently analyzing various options, as outlined below, to serve the Point Roberts load. At this time, the Point Roberts PPA appears to allow PSE to serve customers located in Point Roberts in the most cost-effective manner.

Q. What costs are included in rate year power costs to serve the Point Roberts customer load?

A. PSE's current five-year contract with Powerex expires September 30, 2014 and provides for up to 8 MW at a cost of $[redacted] per megawatt-hour ("MWh"). At this time, [redacted] in rate year power costs.

Q. Why do PSE's rate year power costs include the projected renewal of the Point Roberts PPA?

A. PSE's current Point Roberts PPA with Powerex expires in September 2014. In considering renewal of the agreement, PSE is reviewing alternatives to:

1) serve the Point Roberts load directly via underwater cable;

2) serve the Point Roberts load with a new generation facility located in Point Roberts;

3) serve the Point Roberts load with a distribution tariff through BC Hydro; and

4) serve the Point Roberts load through renewal of the Point Roberts PPA with Powerex.

Over the course of the next several months, prior to the expiration of the current contract with Powerex, PSE expects to finalize its analysis and present a proposal to the EMC to serve the Point Roberts load. PSE will provide this information during the course of this proceeding, and PSE requests permission to update rate year power costs accordingly.

VIII. PROJECTED RATE YEAR POWER COSTS

A. Overview of Projected Power Costs for this Proceeding

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

A. As shown in Table 6 below, PSE's projected rate year net power costs are $751.7 million.

Table 6. Projected Rate Year Power Costs

	($ in thousands)
AURORA	$513,140
Not in Models	$238,604
Projected Rate Year Power Costs	$751,744[9]

Please see Exhibit No. ___(DEM-3) for PSE's projected rate year net power costs. Please also see the Prefiled Direct Testimony of Ms. Katherine 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 Mr. Ronald J. Roberts, Exhibit No. ___(RJR-1CT), for PSE's projected rate year production operations and maintenance ("O&M") costs.

[9] Exhibit No. ___(KJB-4) at page 5, line 9.

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

A. PSE developed projected power costs for the rate year. These projections are based on the information available to PSE during the preparation of the initial filing in this proceeding and, except as noted, are consistent with PSE's prior rate cases.

As discussed in the Prefiled Direct Testimony of Ms. Katherine Barnard, Exhibit No. ___(KJB-1T), PSE adjusted the resulting rate year forecast power costs to test year levels by multiplying by a production adjustment factor. This production adjustment factor represents the ratio of adjusted weather normalized delivered energy loads for the test year to the rate year.

Additionally, the impact of these rate year forecast power costs on this filing is determined by application of the conversion factor and the revenue requirement calculation on a unit cost basis.

Q. How did PSE calculate its power costs for the rate year?

A. 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 are calculated outside of the AURORA model and are referred to as "Not in Models" costs.

Q. What is the AURORA hourly dispatch model?

A. The AURORA hourly dispatch model is a fundamentals-based production cost model that simulates hourly economic dispatch of PSE's generation resource portfolio within the Western Electricity Coordinating Council region. AURORA produces a forecast of the variable operating costs for PSE's generating resources as well as a forecast of regional power prices.

Q. Were there changes made to the AURORA hourly dispatch model since the 2013 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 11.3.1021, which EPIS issued on March 7, 2014. The database used is the North American Database 2014.01 ("2014.01 Database"), which EPIS issued on January 14, 2014. EPIS updated the resource, demand, financial, and regional data within the 2014.01 Database to reflect more recent data, information and economic conditions than those included in the AURORA database used in the 2013 PCORC.[10]

Q. Is AURORA version 11.3.1021 the most recent version of AURORA available?

A. No. EPIS recently issued version 11.4.1006 on April 30, 2014—long after PSE had begun its power cost modeling for this filing.

10 AURORA software version 11.0.1091 was used in the 2013 PCORC, along with the North American Database 2012.01.

Q. Please explain what data sources are used in the AURORA hourly dispatch model for the gas-fired generators and ether PSE intends to update this data during the proceeding.

A. Based on changing circumstances, PSE periodically updates the operating data of its generation resources. PSE gas generation resource operating characteristics and assumptions input to the AURORA model represent those at April 10, 2014. Consistent with prior rate cases, PSE proposes to update AURORA during the PCORC proceeding to comply with the order in Docket Nos. UE-111048 and UG-111049 (the "2011 GRC") that noted the following:

> The Commission consistently strives to reflect the most recent operating and market conditions when setting power costs. In tandem with that aim, is the Company's responsibility to provide an informed record in a timely manner.

2011 GRC Final Order at ¶ 262.

Q. Please explain PSE's projected "Not in Models" 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 "Not in Models" cost. "Not in Models" costs include items such as fixed coal supply costs, mark-to-market for fixed-price gas for power contracts and basis differentials (fixed-price power contracts are included in the AURORA hourly dispatch model), 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 revenues, charges under purchased power agreements and any other power supply costs not included in the AURORA hourly dispatch model.

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 April 10, 2014, 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 2013 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 Coal Transition PPA for the purchase of generation from the Centralia Coal Transition Facility effective December 1, 2014. The rate year reflects $73.3 million of costs under the Coal Transition PPA in return for 1,576,800 MWhs (180 MW) of generation;

(ii) the renewal of the Point Roberts PPA. The rate year reflects $[redacted] million of costs under the Point Roberts PPA in return for 20,729 MWhs of generation;

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

(iv) the expiration on December 31, 2013 of a power purchase agreement with Qualco Energy, LLC for the output of a 450 kilowatt anaerobic digester;

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

(vi) changes in the gas pipeline capacity and pipeline rates for the power book as discussed in the "Not in Models" adjustments below;

(vii) adoption of the regional reliability standard BAL-002-WECC-2 Contingency Reserve effective October 1, 2014, in PSE's winter peak planning calculation to meet winter peak loads and in the calculation of rate year transmission expenses; and

(viii) updates to all rate year power contracts and resources as described above and otherwise to reflect current operations, contract terms and planned maintenance.

Q. How has PSE reflected its Electron Hydroelectric Project in rate year power costs?

A. PSE is still in negotiations to sell the Electron Hydroelectric Project, but the date of executing an agreement for the sale of the Electron Hydroelectric Project is uncertain. In this regard and consistent with the treatment in the 2013 PCORC, PSE has deemed it more appropriate to reflect the Electron Hydroelectric Project as a PSE-owned resource for purposes of determining rate year power costs. The rate year reflects limited forecast hydroelectric generation given the Electron Hydroelectric Project's current capacity limitations. PSE respectfully requests the ability to update for the sale of the Electron Hydroelectric Project should negotiations sufficiently progress during the course of this proceeding. Please see the Prefiled Direct Testimony of Mr. Paul K. Wetherbee, Exhibit No. ___(PKW-1T) for an update regarding the negotiations to sell the Electron Hydroelectric Project.

Q. Are there any other updates regarding PSE's resources?

A. Yes. The rate year power costs reflect the outages for the Baker River Hydroelectric Project discussed in the Prefiled Direct Testimony of Mr. Paul K. Wetherbee, Exhibit No. ___(PKW-1T), and the Prefiled Direct Testimony of Mr. Douglas S. Loreen, Exhibit No. ___(DSL-1T).

<u>2. Projected Hydro Availability</u>

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

A. Consistent with PSE's 2013 PCORC, 2011 GRC and in consideration of the 2009 GRC Order, which noted that future rate cases should include more recent hydro data,[11] PSE has used the average of the 70-year Mid-C streamflow history from 1929 through 1998 to project power costs for the rate year. 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.

2009 GRC Final Order at ¶¶ 124-125.

To be consistent with the Mid-C historical data, PSE used the same 70-year historical west side streamflow records for projections related to PSE's owned hydropower on the west side of the Cascade Mountains. Although there are an additional ten years of streamflow information currently available for forecasting hydro generation, the AURORA model does not yet have the capability to utilize an additional ten years of hydro information. When the AURORA model does have this capability, PSE will present 80 years of streamflow data in rate filings that include power costs.

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

A. The 70 years of hydro generation is input to 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

[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").

markets in which the regional fleet of generating resources is dispatched to meet regional electric loads. AURORA develops 70 results—one for each of the 70 hydro years—and the average of these 70 AURORA model runs is the AURORA model normalized power costs and hydroelectric generation for the rate year.

Q. Does the AURORA model database used to determine the underlying power costs for this rate proceeding include 70 years of hydro data?

A. Yes. The AURORA model database includes 70-year hydro data (1929-1998) for Pacific Northwest areas. In this regard, PSE's use of the 70 years of hydro generation data for the Mid-C and Westside plants is consistent with the AURORA model.

3. Natural Gas Prices

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

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

period ending April 10, 2014. PSE input these data into the AURORA hourly dispatch model for each of the months of the rate year.

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, April 10, 2014, 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 "Not in Models" calculations. An adjustment is also included in the "Not in Models" 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, April 10, 2014). 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 (April 10, 2014 in this proceeding) and the monthly average cost of natural gas hedges that have been 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 "Not in Models" calculation is consistent with the methodology used by PSE in determining rate year power costs since the 2006 GRC.

Q. How do projected gas prices inputs into AURORA for this proceeding compare with those in the 2013 PCORC?

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 gas price at the Sumas trading hub for the rate year is $4.24 per million British thermal units ("MMBtu") (for the three months ended April 10, 2014), which is $0.25 per MMBtu higher than the average $3.99 per MMBtu price included in the

2013 PCORC (for the three months ended August 5, 2013). Table 7 below presents average rate year gas price comparisons.

Table 7. Average Annual Rate Year Gas Prices

Rate Case =>	2014 PCORC	2013 PCORC	2011 GRC	2009 GRC
3-Mo average at =>	4.10.14	8.05.13	4.25.12	8.13.09
Rate Year =>	Dec 14 – Nov 15	Nov 13 – Oct 13	May 12 – Apr 13	Apr 10 – Mar 11
Sumas	$4.24	$3.99	$2.90	$5.97
Change from Prior	$0.25	$1.09	($3.07)	

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 "Not in Models" adjustments.

Since there is no readily available forward gas price for Station 2, PSE has contracted with a third party (Wood Mackenzie) to acquire a forward price forecast of the basis differential between the Alberta Energy Company ("AECO") and Station 2 gas hubs. Specifically, Wood Mackenzie provides an independent forward price forecast of the basis differential between the AECO and Station 2 gas hubs. Because AECO is one of the gas hubs acquired from Kiodex for input to AURORA, PSE may calculate the monthly Station 2 forward gas prices for the rate year by adding the Kiodex AECO 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 forecasts for the rate year period. This methodology is consistent with that explained and used in the underlying power costs approved in the 2011 GRC and the 2013 PCORC.

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 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 "Not in Models" calculation. In addition, some "Not in Models" adjustments update automatically in the MS Excel files whenever a new AURORA model run download is included in the files.

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—in a manner and at a date that enables all parties adequate time to review the proposed changes. In this regard and due to the six month term of this PCORC proceeding, PSE proposes to file updated rate year power costs to reflect more recent three-month average gas prices four weeks prior to the other parties' response filings, which is estimated to be August 2014.

4. 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, F2013, as the rate year demand input to the AURORA model. This F2013 load forecast was approved by PSE's Energy Management Committee in August 2013. The delivered electric load forecast, net of demand-side resources (conservation), for the December 1, 2014 through November 30, 2015 rate year is 22,932,513 MWhs, or 2,618 average megawatts ("aMWs")—an increase of 41,631 MWhs, or five aMWs from the 2013 PCORC load forecast of 22,890,882 MWhs, or 2,613 aMWs. The 2013 PCORC power cost forecast used the then-current load forecast—the F2012 load forecast.

<u>5. "Not in Models" Adjustments</u>

Q. Has PSE included adjustments in the "Not in Models" that are consistent with the adjustments approved in the 2013 PCORC?

A. Yes. Except for the changes discussed in more detail below, PSE has included adjustments in the "Not in Models" calculation that reflect the 2013 PCORC Order.

Q. How has the fracture at the Wanapum Dam affected rate year power costs?

A. PSE contracts with Grant County Public Utility District ("Grant PUD") for a portion of the output from the Priest Rapids Project (which includes the Wanapum and Priest Rapids hydroelectric developments) and, in exchange, PSE pays Grant PUD for a portion of the Priest Rapids Project's O&M and debt costs. PSE includes in rate year power costs both the benefit of the expected hydroelectric generation and the estimated costs under the contract with Grant PUD. Earlier this year, a fracture was discovered at Wanapum dam that has caused current operations to be below normal. Grant PUD is evaluating plans to repair the dam and expects repairs to be finalized this fall, which would be before the start of the rate year, December 1, 2014. In this respect, rate year power costs reflect normal generation from this facility. In accordance with prior rate proceedings, power costs also reflect PSE's contractual share of Grant PUD's budgeted costs for the rate year and estimated benefits associated with Grant PUD's annual power auction. Forecasted power costs do not yet reflect PSE's share of the costs to repair the Wanapum fracture that would be budgeted for the rate year, but PSE expects to have an updated budget from Grant PUD during this proceeding and proposes to update rate year power costs accordingly. In addition, PSE requests approval to update power costs for the final outcome of Grant PUD's 2014 Power Auction which is expected late October 2014.

Q. Has PSE included any changes to the "Not in Models" rate year adjustments?

A. Yes. Although the "Not in Models" adjustments are consistent with those presented in the 2013 PCORC, below are PSE's proposed changes to the "Not in Models" adjustments:

(i) Rate year gas for power pipeline costs have declined $4.6 million from the 2013 PCORC gas for power pipeline costs as a result of

(a) a $3.7 million net increase associated with the termination of 50,000 decatherm ("Dth") per day of Northwest Pipeline ("NWP") firm pipeline capacity from Sumas which has been replaced with a 50,000 Dth per day agreement with Gas Transmission Northwest, LLC ("GTN") from Stanfield;

(b) a $4.3 million decrease due to the future expiration of a Westcoast Energy, Inc. ("Westcoast") contract on October 31, 2014; and

(c) a $4.2 million reduction in Westcoast pipeline rates; and

(ii) Transmission costs include the renewed transmission contracts with BPA as well as BPA's rate increase effective October 1, 2015.

Q. Why did PSE terminate 50,000 Dth per day of NWP firm pipeline capacity from Sumas and replace it with a new contract of the same amount from Stanfield?

A. As discussed in the Prefiled Supplemental Direct Testimony of R. Clay Riding in PSE's 2009 General Rate Case (Docket Nos. UE-090704 & UG-090705), PSE made arrangements in October 2010 to acquire 50,000 Dth per day of long-term temporary release firm capacity from the Stanfield interconnect with Gas Transmission Northwest ("GTN") for the period November 1, 2014 through March 31, 2025, to replace the 50,000 Dth per day temporarily available discounted capacity from Sumas. PSE was subsequently able to extend the Sumas originating firm capacity until October 2014, and has secured the 50,000 Dth per day Stanfield originating firm capacity on a permanent basis from April 1, 2025 through March 31, 2035. The shift in receipt point capacity from Sumas to Stanfield, effective November 1, 2014, in combination with prior changes in PSE's portfolio, provides diversity of both physical gas supply and pricing for the PSE Gas for Power portfolio. Gas received into the NWP system at Stanfield can be originated in Alberta, Canada or the U.S. Rockies via GTN and other upstream pipeline systems.

Q. Please describe the $8.5 million reduction in Westcoast pipeline charges.

A. Approximately half of the reduction in Westcoat pipeline charges is due to the planned expiration of a 21,872 Dth per day contract on Westcoast effective October 31, 2014. PSE considered the expiration when it contracted additional Westcoast pipeline capacity at the time of the acquisition of the Ferndale Generating Station. The staggered termination dates for Westcoast pipeline service allowed PSE to maintain its 50% diversity goal for firm gas needs at the Sumas trading hub. With the shifting of firm requirements from Sumas to Stanfield, PSE no longer requires as much capacity on Westcoast's pipeline to maintain the diversity goal.

The remainder of the reduction in Westcoast pipeline charges is due to lower rates on the Westcoast pipeline system, which, in turn, has two primary causes. First, despite an overall increase in annual cost of service, Westcoast pipeline firm contract levels are higher today than in recent years, and the pipeline has transported greater interruptible volumes, which together have resulted in lower rates, which are reset each year. Second, the Westcoast pipeline rates are in Canadian dollars, and the U.S. dollar has strengthened against its Canadian counterpart since 2013 PCORC rates were set, further reducing forecast power costs.

IX. COMPARISON OF PROJECTED POWER COSTS TO THE PROJECTED POWER COSTS IN THE 2013 PCORC

Q. What are the principal differences between the power cost projections in this proceeding and the power cost projections approved in the 2013 PCORC?

A. The power cost projection in this case is approximately $17.4 million *higher* than the power costs projections approved in the 2013 PCORC. Please see Exhibit No. ___(DEM-4C) for a resource by resource comparison of the projected power costs and generation for the 2013 PCORC rate year (November 1, 2013 through October 31, 2014) and the projected power costs for the rate year in this proceeding (December 1, 2014 through November 30, 2015).

Q. What are the causes of the change in projected power costs relative to the 2013 PCORC?

A. The following items caused the majority of the change to projected rate year power costs from the 2013 PCORC:

(i) increased costs due to the Coal Transition PPA for 180 MW of power;

(ii) lower costs due to the expiration of a purchased power contract, as noted above, which has been replaced with lower priced market power;

(iii) lower costs due to lower fixed-price short term power and gas for power contracts;

(iv) lower costs due to increased hydro generation under PSE's Mid-C contract as a result of updating for a more current regulation;

(v) decreased gas pipeline costs as discussed above;

(vi) increased costs due to an increase of 5 aMWs of forecast load;

(vii) a net increase in Colstrip costs due to higher average coal costs, mitigated by lower fixed costs and less planned maintenance;

(viii) increased costs due to higher rate year average gas prices and AURORA-derived rate year market power prices, as discussed above;

(ix) increased BPA transmission costs due to transmission contracts approved in the 2013 PCORC that are included for a full year as well as tariffs effective October 1, 2015, as discussed above;

(x) higher costs forecast to integrate PSE's wind resources, and

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

X. INTRODUCTION OF PSE WITNESSES

Q. Would you please describe briefly PSE witnesses and the topics presented by each witness in this case?

A. The following additional witnesses present direct testimony on PSE's behalf:

Ms. Janet Phelps, Senior Energy Resource Planning Acquisition Analyst for PSE, describes the quantitative analyses undertaken by PSE in considering renewing transmission contracts with BPA.

Mr. Ronald J. Roberts, Director of Thermal Resources for PSE, summarizes the rate year production O&M costs and provides details of the production O&M for PSE's thermal generation fleet.

Mr. Paul K. Wetherbee, PSE Director of Hydroelectric and Wind Resources Assets Management for PSE, provides an update on PSE's Electron Hydroelectric Project, describes the Baker River

Hydroelectric Project license implementation and production O&M for PSE's hydro and wind facilities.

Mr. Doug Loreen, Director of Project Delivery for PSE, describes the updated costs for PSE's Snoqualmie Hydroelectric Redevelopment Project, Lower Baker Hydroelectric Floating Surface Collector and Lower Baker Hydroelectric New Powerhouse.

Ms. Katherine Barnard, Director of Revenue Requirements and Regulatory Compliance for PSE, discusses the equity component of the Coal Transition PPA, and presents the electric results of operations, the revenue requirement surplus, and the PCA mechanism baseline rate.

Mr. Jon Piliaris, Manager of Pricing and Cost of Service for PSE, presents PSE's electric cost of service, rate spread and rate design.

XI. 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 $751.7 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.