EXHIBIT NO. ___(TAD-1CT)
DOCKET NO. UE-16____
PCA 14 COMPLIANCE
WITNESS: TOM A. DEBOER

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of **PUGET SOUND ENERGY** **For Approval of its April 2016 Power Cost Adjustment Mechanism Report**	**Docket No. UE-16____**

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF TOM A. DEBOER ON BEHALF OF PUGET SOUND ENERGY

REDACTED VERSION

APRIL 29, 2016

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF TOM A. DEBOER

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I. INTRODUCTION

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

A. My name is Tom A. DeBoer. 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. ___(TAD-2).

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

A. As Director, Energy Supply Merchant, my responsibilities include providing policy direction on federal and regional issues, managing filings and proceedings before the Federal Energy Regulatory Commission ("FERC") and the Bonneville Power Administration ("BPA"), directing the trade floor hedging functions and the planning and analyses supporting the energy supply and transmission needs of PSE, and oversight of the FERC, North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") compliance obligations for Energy Supply Operations.

Q. Please summarize the contents of your testimony.

A. First, I provide some brief background information regarding the Power Cost Adjustment ("PCA") Mechanism and how it addresses the volatility of PSE's power costs. Then I describe the changes in power resources from those included in current rates, as well as PSE's efforts to manage its power costs during the period that began on January 1, 2015 and ended on December 31, 2015 ("PCA Period 14"). I then compare PSE's actual power costs for PCA Period 14 to the baseline power cost rates that were in effect for PCA Period 14. See the Prefiled Direct Testimony of Katherine J. Barnard, Exhibit No. ___(KJB-1T), for further information regarding the PCA baseline rates for the PCA Period 14. The baseline power cost rate approved in the 2014 Power Cost Only Rate Case, WUTC Docket No. UE-141141 ("2014 PCORC") went into effect December 1, 2014.

II. BACKGROUND REGARDING THE PCA MECHANISM

Q. Why does PSE have a PCA Mechanism?

A. The parties to PSE's 2001 general rate case were keenly aware from the experience of the Western Power Crisis in 2000-2001 how volatile power prices can be. In response to that volatility and uncertainty in the wholesale energy markets as well as PSE's need to add resources to meet its load obligations, the parties who participated in the PCA settlement collaborative in PSE's 2001 general rate case agreed to a negotiated PCA Mechanism. The Commission approved the PCA Mechanism in its Twelfth Supplemental Order in PSE's 2001 general rate case, Docket Nos. UE-011570 and UG-011571. The PCA Mechanism became effective

July 1, 2002.

Q. Please describe why power costs can be volatile.

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: (1) streamflow variation affecting the supply of hydroelectric generation; (2) weather uncertainty affecting power usage; (3) variations in market conditions such as wholesale gas and electric prices; (4) risk of forced outages; (5) variability of wind generation; and (6) transmission and transportation constraints. All of these have an impact on load and resource volatility, which PSE may balance with wholesale market purchases and sales. These same volatility factors also affect the wholesale power markets in general.

Q. How does the PCA Mechanism work?

A. Generally, the PCA Mechanism is an annual accounting process to share costs and benefits between PSE and its customers over four graduated levels (so-called "bands") for the first $120 million of power cost variances. For power cost variances over $120 million, the PCA sharing mechanism allocates 95 percent of costs or benefits to customers and the remaining five percent of costs or benefits to PSE.

Q. What do you mean by "power cost variances"?

A. Power cost variances are the annual difference between: (1) the actual recovery of

power costs based on the "baseline" fixed and variable power costs that are built into PSE's electric rates: and (2) the sum of PSE's actual variable power costs allowed under the PCA Mechanism plus the fixed power costs as determined in the most recent rate proceeding. For example, during the PCA Period 14, PSE under recovered $8.7 million of its actual allowed variable and fixed power costs. PCA Period 14 actual power costs are discussed in more detail in section III.C. of my testimony. See Ms. Barnard's Prefiled Direct Testimony, Exhibit No. ___(KJB-1T), for further information and discussion of the PCA Annual Report for PCA Period 14.

Q. How are PSE's costs for new resources treated in the PCA Mechanism?

A. Under the PCA Mechanism, new resources with a term *less* than or equal to two years are included in allowable PCA costs. The prudence of such resources is determined in the Commission's review of the annual PCA true-up. Power costs related to a new electric resource with a term *greater* than two years are included in allowable PCA costs through a bridge mechanism known as PCA Exhibit G, "New Resource Adjustment." If the cost of the new resource exceeds the baseline rate, Exhibit G reduces the PCA mechanism's variable costs of the new resources to be equivalent to the baseline rate until the prudence of such resources can be reviewed and approved in a power cost only or general rate case.

Q. Were there new resources that triggered the PCA Exhibit G calculation during the PCA Period 14?

A. No. There were no new resources that triggered the PCA Exhibit G calculation

during PCA Period 14.

III. PCA PERIOD 14 POWER COSTS

A. PCA Period 14 Power Resources

Q. Please describe the changes to long-term electric supply resources that are different than those included in the baseline rates during PCA Period 14.

A. As noted above, the baseline rates in effect during the PCA Period 14 reflect the power portfolio from PSE's 2014 PCORC. There were a few changes to PSE's portfolio that are reflected in the PCA Period 14 power costs that are different than those recovered in rates for the entire PCA Period 14. Specifically, PCA Period 14 actual power costs included:

(1) Existing contract changes and expirations:

a. a 100 MW increase in delivered power per the terms of the Centralia Coal Transition PPA contract effective December 1, 2015;

b. a 75 MW decrease due to the expiration of Barclays' long term contract effective December 1, 2015;

(2) New contracts executed under PSE's Schedule 91 Tariff, "Cogeneration and Small Power Production";

(3) Changes to fixed gas transportation contracts to continue to support the physical gas requirements of PSE's gas fired generation:

a. 37,913 Dth per day with Nova Gas Transmission Ltd. from NIT to A/BC effective December 1, 2015;

b. 40,946 Dth per day with Foothills Pipeline from A/BC to Kingsgate effective December 1, 2015;

c. 40,567 Dth per day with Gas Transmission Northwest from Kingsgate to Stanfield effective November 1, 2015;

d. Plymouth LNG storage with Northwest Pipeline that provides 70,500 Dth per day demand and 241,700 Dth storage capacity effective November 1, 2015;

e. 34,197 Dth per day winter only with Northwest Pipeline from Jackson Prairie to Longview and Sedro-Woolley effective November 1, 2015;

f. 15,000 Dth per day with Northwest Pipeline from Plymouth to Sedro-Woolley, with segmentation at Jackson Prairie, effective November 1, 2015, and

g. 20,000 Dth per day with Northwest Pipeline from Sumas to Jackson Prairie effective October 10, 2015.

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

Q. Did PSE acquire any new resources during PCA Period 14 with a term of less than or equal to two years?

A. Yes. PSE acquired such resources in the form of off-system physical or financial purchases and sales of power and fuel to generate power. The majority of such transactions during this period were short-term balancing transactions of power and natural gas for power purchases and sale contracts. Such balancing transactions are made in response to changes in load or resource availability as well as changes in market heat rates, which guide PSE decisions of whether to dispatch gas-fired generation or to buy power and sell hedged natural gas for power. Such transactions include intermediate term transactions entered into pursuant to PSE's programmatic portfolio hedging efforts.

PSE also purchased winter on-peak index power to secure firm power supply to PSE's system.

Q. Why did PSE enter into the various transactions described above?

A. These transactions were undertaken within a comprehensive portfolio and risk

management system of organizational structure, technological tools, and human resources designed to allow PSE to: (1) deliver reliable energy when its customers demand it, (2) serve its customers while mitigating price volatility, and (3) enhance the utilization of PSE's energy resources.

PSE has had organizational structures, policies and overarching strategies in place for many years to provide oversight and control of 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 months. PSE uses these tools to develop and implement strategies to reduce the cost risks associated with portfolio volatility.

The following section of my testimony first provides a description of these systems and tools. I then illustrate their application to PCA Period 14 by describing actual hedging strategy decisions and their execution undertaken by PSE with respect to its power supply for a sample month, February 2015. *See* Exhibit No. ___(TAD-3C).

B. PSE's Management of its Power Portfolio and Related Fuel Supply for PCA Period 14

1. Overview of PSE's Portfolio and Risk Management Systems

Q. What organizational structures are in place to provide oversight and control of power portfolio management activities?

A. During PCA Period 14, PSE's Energy Supply Merchant ("ESM") department

included certain employees performing Portfolio Hedging and Power and Gas Supply Operations functions. The ESM department is composed of energy market analysts, quantitative analysts, seasoned energy traders and other professionals. The ESM department is responsible for monitoring the energy portfolio and identifying, quantifying, monitoring and recommending risk management strategies for PSE. The ESM department performs these tasks and manages PSE's short- and medium-term portfolios. During PCA Period 14, the ESM was under my direction.

The Energy Risk Control ("ERC") department includes the employees who perform credit analysis and is also responsible for independently monitoring, measuring and reporting official risk positions. The ERC department is led by the Corporate Treasurer.

PSE's Energy Management Committee ("EMC") – composed of five PSE officers – oversees the activities performed by the ESM department. The EMC is responsible for providing oversight and direction on all portfolio risk issues in addition to approving long-term resource contracts and acquisitions. The EMC provides policy-level and strategic direction on a regular basis, reviews position reports, sets risk exposure limits, reviews proposed risk management strategies, and approves policy, procedures and strategies for implementation by PSE staff. In addition, PSE's Board of Directors provides executive oversight of these areas through the Audit Committee.

Q. What hedging strategies have been approved by the EMC?

A. With respect to hedging strategies for specific time periods or quantities of energy,

the EMC has approved a Programmatic Hedging Strategy. The original programmatic hedging strategy was approved by the EMC on July 22, 2004, with a PSE staff transactional purview of [redacted]. The term of the EMC approved programmatic hedge strategy originally consisted of the last [redacted] of the [redacted] purview ("Programmatically Managed Hedge"), but was reduced to [redacted] in early 2006. The balance of the [redacted] purview was actively managed ("Actively Managed Hedge") in accordance with the EMC approved Energy Supply Hedging and Optimization Procedures Manual ("Procedures Manual"). In October 2007, PSE extended department staff's transactional purview from [redacted] to [redacted]. At that time, the balance of the current month plus the first full [redacted] became the Actively Managed Hedge in accordance with the Procedures Manual and the latter [redacted] (the period always includes a full calendar quarter, so it varies from [redacted]) became the Programmatically Managed Hedge in accordance with the EMC approved strategy. ESM department staff utilize the Programmatically Managed Hedge process to systematically reduce PSE's net power portfolio exposure beginning [redacted] in advance of the month in which the power will be needed to serve PSE's load. This process is described in greater detail below and in Exhibit No. ___(TAD-3C), which also steps through a sample month, February 2015. Such exposure reduction is subject to minimum and maximum monthly limits to reduce timing and market risks associated with hedging activities. Decisions about hedges for delivery during the Actively Managed Hedge are made by ESM department staff, within limits set out in PSE's Procedures Manual.

Q. How does PSE integrate hedging activities with its power portfolio modeling?

A. PSE's risk system employs production cost modeling techniques to estimate future demand for on- and off-peak power and natural gas for PSE's fleet of gas-fired power plants. This risk system permits PSE to model scenarios of prices, hydro conditions, load projections, generating and contracted resources and other inputs as required to represent future projected portfolio needs.

To model a variety of scenarios regarding PSE's gas-fired generation, the risk system takes into account each plant's individual operating characteristics, including: unit efficiency, start-up costs, variable operating costs, minimum run times, planned and unplanned outages, and unit availability. The risk system performs simulations of different market conditions and various outages in order to develop an estimate of the gas volumes required to produce a volume of power. The plants are modeled on an hourly basis and the information is aggregated into daily and monthly time frames for purposes of developing a forward-looking position. The risk system incorporates information about hedges that PSE staff has already executed to model whether the portfolio is surplus or deficit. The risk system incorporates the inter-relationship between gas and power prices in developing its probabilistic gas and power positions. In different market scenarios, PSE's gas or power requirements will change. The reason for this is twofold. First, the plants have different operating efficiencies (known as "heat rates") and become economic to dispatch at different price differentials between power and gas. Second, the forward market prices for power and gas change frequently and the

price relationship between power and gas, known as the "implied market heat rate", change as well. At certain implied market heat rates, PSE will expect to run each plant at an expected rate, and the total of all the plant requirements can be calculated. But if market conditions change, PSE will expect to adjust its gas and power purchases and sales in order to serve load with the most economic resources. For example, it may be more economical to purchase power than to purchase gas to generate the power PSE needs to serve its load.

Q. Please describe the output that the electric portfolio risk system produces.

A. The risk system generates a probabilistic volumetric position report, comprised of 250 scenarios, for on- and off-peak power and gas for power. The position report shows, for each of the months following the date of the report, the resource types in PSE's power position grouped by: short-term purchase and sale transactions, long-term contracts, Combustion Turbines ("CT") grouped by heat rate efficiency of the facilities, Non-Utility Generators/Qualifying Facilities ("NUGs/QFs"), Coal Plants, Wind and Hydro (both PSE-owned and Mid-C contracts). Based on this volumetric position for each month, the risk system also generates the potential exposure associated with the "open" positions (defined as any net surplus or deficit amount as compared to the load demand). *See* Exhibit No. ___(TAD-4C).

Q. How does PSE use the electric portfolio risk system to help make hedging decisions?

A. Once PSE's aggregated energy position and net exposure are defined for a particular period, the ESM department staff evaluates and develops risk

management strategy proposals and/or executes transactions around the purchase or sale of gas or power, as appropriate, to ratably move toward a balanced position and reduced exposure. Execution entails entering into specific transactions with approved counterparties, approved instruments, executed master agreements and available credit.

Q. How does PSE use the risk system to implement its Programmatic Hedging Plan?

A. As described above, PSE's Programmatic Hedging Plan is set up to systematically reduce the total net exposure for each of the [redacted] beyond the next [redacted] timeframe, within maximum and minimum parameters on the amount of hedging that can or must be done each month, so that the total net exposure for each month will fall within the limits set forth in the Procedures Manual. Every month, the risk system calculates the total net exposure to be reduced for each of the months in the Programmatically Managed Hedge period.

Q. Does Energy Supply Merchant staff implement the Programmatic Hedging Plan by relying only on the net exposure?

A. No. The net exposure drives transactions only to the point of showing whether PSE's exposure is within the maximum and minimum monthly parameters of the plan. ESM department staff then makes use of both technical analysis and market fundamentals (water supply, weather forecasts, regional renewable additions and natural gas storage, to name a few) that impact the wholesale electric and gas markets to decide on the volume to hedge while remaining within the monthly

parameters. ESM department staff also determines when and how to execute such transactions to maintain each month's net exposure reduction.

Q. How does Energy Supply Merchant staff develop a view of appropriate hedging strategies for the power portfolio?

A. The ESM department staff utilize a wide set of tools and sources of information to help them make informed decisions about dispatching plants, purchasing fuel and executing hedges approved by the EMC. They also hold regular meetings to review operational events, discuss market trends, fundamentals and technical analysis and review supply and demand information. Within this context, the teams work together to understand the exposures in the portfolio and discuss where hedging priorities occur. Underlying all this teamwork is an ESM department staff with years of experience in energy trading, optimization and risk management.

Q. What types of information does the Energy Supply Merchant staff consider?

A. The ESM department staff collects a wide range of data to monitor supply/demand factors, which include but are not limited to: weather trends; macro-economic factors; crude oil markets; gas storage inventories across the United States, Canada and in the western United States; hydro run-off forecasts; reservoir storage; precipitation and snow pack; and more. Additionally, they review forecasted wholesale market prices and supply/demand fundamentals, such as trading firm publications and consulting service forecasts.

ESM department staff also receives real-time information from a variety of sources

such as: McGraw Hill (Gas Daily, Megawatt Daily), Future Source, Intercontinental Exchange (live price data), live broker lines where current transactions are communicated through a speaker system, and other tools. The ESM department staff also has instantaneous data coming from PSE's systems operations staff so they can view load and generation dispatch data on a real-time basis.

In addition to using such information and processes to implement the current Programmatic Hedging Plan, the ESM department staff use such information to develop recommendations to the EMC regarding potential changes to PSE's overarching hedging strategies or to recommend transactions that do not fall within those strategies.

Q. Does PSE use any other tools to manage its energy portfolio?

A. Yes. PSE uses a counterparty credit risk management system in establishing and monitoring counterparty credit limits. Counterparty exposure is calculated and monitored frequently and ESM department staff is permitted to transact only within the established credit limits.

Q. What guidance does PSE have in place for approaching risk management strategy proposals?

A. Many years ago, PSE moved from a more "discretionary" model of making hedging decisions to a more "programmatic" approach to hedging. This "dollar-cost averaging" strategy established a disciplined approach to purchasing a defined

volume of gas or power on a monthly basis. In applying this strategy, PSE typically established plans to purchase hedges for specific forward time periods, with the goal of purchasing a defined amount of power and gas in order to ratably reduce the deficit positions by a small amount each month.

By spring 2003, the EMC had approved expansion of this concept to an "Exposure-based Dollar Cost Averaging." This refinement moved PSE from defining a specific commodity and volume to be hedged every month to a dollar amount of risk reduction to be accomplished every month. Under this approach, the EMC would approve a dollar figure of risk to be reduced, and PSE staff would determine whether it was better to hedge gas or power. As market prices move up or down, the dollar amount allows for less or greater volumetric purchases of power or gas for power.

In July 2004, the EMC approved a continuation of a dollar cost averaging strategy (hedging on a regular schedule over a lengthy period). However, the EMC directed that ESM department staff monitor and more actively address the exposure associated with PSE's power portfolio position [redacted] ahead of the time the power would be needed. On January 7, 2006, the Rolling [redacted] Hedging Plan was amended to be a Rolling [redacted] Hedge to guide hedging decisions for the [redacted] to [redacted] time frame. In October 2007, this hedging plan was extended and now covers the [redacted] to [redacted] time frame ("Programmatically Managed Hedge"). This hedging plan reduced hedge concentration by extending the dollar cost averaging approach to a longer period of time, and increased staff's ability to react to position

changes as a result of forecast customer demand, stream-flow variations, forced thermal plant outages, and changing market conditions.

ESM department staff use the Programmatically Managed Hedge to systematically reduce PSE's net power portfolio exposure (including natural gas for power generation) beginning [redacted] in advance of the month in which the power is needed to serve PSE's load.

Q. How does the Programmatically Managed Hedge Plan work?

A. The Programmatically Managed Hedged Plan is a multi-year strategy designed to ratably reduce the power portfolio's total net exposure for each month, so that the total net exposure will fall below the EMC exposure limits set forth in the Procedures Manual. Monthly hedge limits for the Programmatic Managed Hedge are calculated by dividing the total net exposure by the remaining months prior to the time when the position falls into the Actively Managed Hedge. The "maximum" monthly parameter for the Programmatic Managed Hedge is calculated by dividing the total net exposure by the remaining months prior to the time when the position falls into the Actively Managed Hedge term. The "minimum" monthly parameter is calculated by dividing the total net exposure (plus or minus the Director's limit authority) by the remaining months prior to the time when the position falls into the Actively Managed Hedge. If such a month's position already falls within the Director's exposure limit authority, there is no monthly hedge requirement.

Q. Why did PSE extend its hedging strategies?

A. Prior to extending the term of the hedging strategies, PSE engaged in a very detailed best-practices benchmarking and market research initiative. These efforts revealed that customers prefer a longer period of rate stability and that industry leading companies were engaged in longer term hedging practices than PSE. Given this and other information, PSE determined it could be beneficial to expand its hedging horizons.

2. Application of PSE's Risk Management System to PCA Period 14 Power Costs

Q. Would you provide some examples of how PSE applied the risk management systems, tools and strategies described above with respect to PCA Period 14 power supply and costs?

A. Yes. Take, for example, PSE's power demand for February 2015. In [redacted], February 2015 rolled into staff's Programmatically Managed Hedge purview. PSE's ESM staff began to actively reduce spot market price exposure for the delivery period February 2015. From [redacted] through [redacted], on a monthly basis, ESM department staff developed strategies to programmatically reduce PSE's power cost exposure for February 2015. Strategies incorporated hydro conditions, weather, supply/demand fundamentals, implied market heat rates and updated Position and Exposure Reports generated by PSE's risk system. See Exhibit No. ___(TAD-3C) for discussion of the hedges transacted for February 2015, which are presented in Exhibit ___(TAD-6C).

Beginning in February 2014, the power supply for February 2015 rolled into staff's Actively Managed Hedge – at which point staff continued to analyze PSE's position for February 2015 on a daily basis and, based on market conditions and other information available to them at the time, how and when to reduce PSE's exposure under the authority and limits of the Procedures Manual.

Documenting these activities requires detailed description and explanation of the information and reports used by PSE at each stage of its consideration, decision making, and execution of PSE's risk management strategies. Thus, this description and documentation is presented separately as Exhibit No. ___(TAD-3C).

Q. Are the activities described in Exhibit No. ___(TAD-3C) the only risk management activities that PSE undertook for PCA Period 14?

A. No. Similar activities were undertaken with respect to managing PSE's portfolio and exposure for the entire PCA Period 14.

3. <u>Winter Peaking Contracts</u>

Q. Why does PSE enter into winter peaking contracts?

A. Winter peaking contracts are to help reliably serve high loads during extreme winter peak events.

Q. How did PSE approach the decisions of whether and how to enter into winter peaking contracts for the winter months of calendar year 2015?

A. PSE approached these decisions within the context of its portfolio and risk

management systems and procedures. Staff used peak winter load/supply modeling and ultimately decided that it would purchase winter [redacted] power [redacted] transactions to ensure firm physical power supply during the winter peaking hours.

C. PSE's PCA Period 14 Actual Power Costs

Q. How have PSE's recoveries of power costs compared to those set in rates?

A. During PCA Period 14, PSE's rates under-recovered actual power costs by $8.7 million. Since this amount is within the $20 million dead-band, PSE will absorb the full amount of $8.7 million under-recovery and there will be no sharing of costs with customers.

Q. Why do actual power costs differ from those set in rates?

A. The actual costs of power delivered to PSE's system will always differ from those set in rates because they reflect the actual resources available to PSE, as discussed above, and the actual outcome of power costs variables. Examples of these variables include:

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

(ii) weather uncertainty affecting power usage;

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

(iv) forced generation outages;

(v) variability of wind generation;

(vi) differences in actual resources in the power portfolio versus those set in rates due to contract expirations, contract changes

and resource acquisitions, and

(vii) transmission and transportation constraints.

Although power costs set in rates are estimated "as closely as possible to costs that are reasonably expected to be actually incurred,"[1] they are still forecasts of future events and are further limited by regulatory normalizing assumptions. Specifically, ratemaking in the 2014 PCORC normalized the power cost volatilities by employing:

(i) a 70-year hydro data set to determine hydro generation,

(ii) a weather normalized load forecast,

(iii) a three-month average forward gas price forecast,

(iv) model generated forward power prices,

(v) historical average forced outage rates, and

(vi) forecast average wind generation.

Q. What caused the difference during PCA Period 14 between PSE's actual power costs and power costs recovered in rates?

A. PSE's $8.7 million under-recovery of amounts recovered through the Power Cost Baseline Rate during the PCA Period 14 was due to lower baseline rate revenues caused by lower customer demand than was forecast as well as overall warmer temperatures for the first three quarters of 2015. Actual delivered load was 787,780 MWh lower than the forecast load provided in rates. This caused baseline rate revenues to be $47.1 million below the forecasted level. These lower revenues

[1] *WUTC v. Puget Sound Energy, Inc.*, Docket Nos UE-040640, *et al.*, Order 06 at ¶108 (Feb. 18, 2005).

were partially offset by a decrease in power costs relative to forecast in the amount of $38.4 million.

The major reasons power costs were below forecast are: (i) lower customer demand causing PSE to purchase or generate less power during PCA Period 14; (ii) lower costs to generate power from PSE's gas fired generators; (iii) lower coal generation and costs; (iv) lower long-term contracts costs; (v) and higher transmission revenue.

The overall loss of load caused a decrease in power costs of approximately $15.7 million. While power costs remained lower than those set in rates overall, this decrease was partially offset during periods of higher temperatures and higher than forecast load that occurred during the months of June and July when temperatures averaged nine degrees higher than normal. During this spike in customer demand, wind and hydro generation were below normal, forcing purchases from the market at inflated prices. Table 1 below shows the average cost of power and gas compared to those set in rates for calendar year 2015.

Table 1: Average Power and Gas Prices and Market Heat Rates
Calendar Year 2015 Compared to Prices in Rates

	Actuals			Rates (14PCORC)			Difference		
	2015	Jun'15	Jul'15	2015	Jun'15	Jul'15	2015	Jun'15	Jul'15
MidC Flat ($/MWh)	$23.45	$32.27	$33.82	$31.68	$28.54	$31.46	($8.23)	$3.73	$2.36
Sumas ($/MMBtu)	$2.31	$2.25	$2.26	$3.86	$3.35	$3.52	($1.55)	($1.10)	($1.26)
Flat Heat Rate	10.16	14.31	14.98	8.22	8.52	8.95	1.94	5.79	6.03

Q. Please provide a summary of how the power resources used to serve load compare to those set in rates for PCA Period 14.

A. Table 2 provides an itemization of the changes in generation and retail loads from those included in the baseline rate for PCA Period 14.

Table 2: 2015 Generation and Load Differences from Rates

Generation Higher / (Lower) than Rates (in aMW's):	Change aMW	Change %
Hydro	(42)	-8.4%
Colstrip	(58)	-10.1%
Gas Fired	186	38.8%
Wind	(41)	-16.3%
Contracts	3	1.2%
Market Purchases and Sales	(150)	-27.6%
Load (Generated, Purchased & Interchanged)	(101)	-3.9%
Delivered Load	(90)	-3.7%

Q. Please provide a summary of the power cost variances for PCA Period 14 compared to those set in rates.

A. Table 3 provides a summary of the items which caused the calculated $8.7 million under recovery of power costs for PCA Period 14.

Table 3: Components of CY 2015 PCA Under Recovery
($ in millions)

Over / (Under) Recovery - Actuals vs Rates:	CY 2015
Revenues	
Delivered Load Lower by 787,780 MWh	($47.1)
Allowed Costs	
Load (GPI) Lower by 885,477 MWh	15.7
Hydro Generation	(13.6)
Gas Fired Generation	29.4
Wind Generation	(5.7)
Coal Generation and Costs	6.7
Long-Term Contracts	3.4
Transmission Revenues	1.7
Other	0.6
Total Allowed Costs	38.4
2015 PCA Under Recovery of Power Costs	**($8.7)**

Q. Are PSE's PCA Period 14 actual allowable power costs net of any accounting adjustments?

A. No, there were no accounting adjustments made to the actual PCA Period 14 power costs.

IV. CONCLUSION

Q. Has PSE met the Commission's prudence standard with respect to its power costs during PCA Period 14?

A. Yes; PSE met the Commission's prudence standard for the PCA Period 14 power costs because PSE's management of its power costs during PCA Period 14 was

reasonable. PSE has structures and processes in place to formulate strategies for managing power costs and executed those strategies, taking into account information and variables associated with managing a complex resource portfolio within a dynamic market environment.

Q. Does that conclude your testimony?

A. Yes, it does.