

**EXHIBIT NO. ___(DEM-1CT)
DOCKET NO. UE-12___
PCA 10 COMPLIANCE
WITNESS: DAVID E. MILLS**

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

**In the Matter of the Petition of
PUGET SOUND ENERGY, INC.
For Approval of its March 2012 Power Cost
Adjustment Mechanism Report**

Docket No. UE-12___

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

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VERSION**

MARCH 30, 2012

PUGET SOUND ENERGY, INC.

**PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
DAVID E. MILLS**

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1 **PUGET SOUND ENERGY, INC.**

2 **PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF**
3 **DAVID E. MILLS**

4 **I. INTRODUCTION**

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

7 A. My name is David E. Mills. My business address is 10885 N.E. Fourth Street,
8 Bellevue, Washington, 98004-5591. I am the Director, Energy Supply and
9 Planning for Puget Sound Energy, Inc. ("PSE").

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

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

13 **Q. What are your duties as Director, Energy Supply & Planning for PSE?**

14 A. My responsibilities include oversight of PSE's Power Supply Operations and Gas
15 Supply Operations departments, including the following: (i) managing all PSE
16 short-term (intra-month) and medium-term (up to three years) wholesale power and
17 natural gas portfolios; and (ii) working with PSE's Energy Resources department to
18 plan for long-term hedging requirements. My responsibilities also include
19 developing strategies to address risks related to PSE's electric and gas portfolios
20 and developing PSE's Transmission Strategies.

1 **Q. Please summarize the contents of your testimony.**

2 A. First, I provide some brief background information regarding the Power Cost
3 Adjustment ("PCA") Mechanism and how it addresses the volatility of PSE's power
4 costs. Then I discuss Renewable Energy Credit ("REC") transactions. I then
5 describe the changes in power resources from those included in current rates, as
6 well as PSE's efforts to manage, control and moderate its power costs during the
7 period that began on January 1, 2011 and ended on December 31, 2011 ("PCA
8 Period 10"). Finally, I compare PSE's actual power costs for PCA Period 10 to its
9 baseline power cost rates that were in effect for PCA Period 10. See the Prefiled
10 Direct Testimony of Mr. John H. Story, Exhibit No. ___(JHS-1T), for further
11 information regarding the PCA baseline rates for the PCA Period 10. The baseline
12 power cost rates from PSE's 2011 general rate case, WUTC Docket No. UE-
13 111048 are expected to go into effect during May 2012.

14 **II. BACKGROUND REGARDING THE PCA MECHANISM**

15 **Q. Why does PSE have a PCA Mechanism?**

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

1 011571. The PCA Mechanism became effective July 1, 2002.

2 **Q. Please describe why PSE's power costs can be volatile.**

3 A. PSE's power supply portfolio contains a diverse mix of resources with widely
4 differing operating and cost characteristics. Although there are many complex
5 variables embedded in the portfolio, the major drivers of power cost volatility are:
6 (1) streamflow variation affecting the supply of hydroelectric generation;
7 (2) weather uncertainty affecting power usage; (3) variations in market conditions
8 such as wholesale gas and electric prices; (4) risk of forced outages; (5) variability
9 of wind generation; and (6) transmission and transportation constraints. All of these
10 have an impact on load and resource volatility, which PSE may balance with
11 wholesale market purchases and sales.

12 **Q. How does the PCA Mechanism work?**

13 A. Generally, the PCA Mechanism is an annual accounting process to share costs and
14 benefits between PSE and its customers over four graduated levels (so-called
15 "bands") for the first \$120 million of power cost variances. For power cost
16 variances over \$120 million, the PCA sharing mechanism allocates 95 percent of
17 costs or benefits to customers and the remaining 5 percent of costs or benefits to
18 PSE.

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

20 A. Power cost variances are the annual difference between (1) the "baseline" fixed and
21 variable power costs that are built into PSE's electric rates and (2) the sum of PSE's

1 actual variable power costs allowed under the PCA Mechanism plus the fixed
2 power costs, as determined in the most recent rate proceeding. For example, during
3 PCA Period 10, PSE's actual power costs were \$34.8 million below the amounts
4 recovered through the power cost baseline rate and are discussed in more detail in
5 section IV.C of my testimony. See the Prefiled Direct Testimony of Mr. John H.
6 Story, Exhibit No. ___(JHS-1T), for further information and discussion and the
7 PCA Annual Report reflecting the \$34.8 million power cost variance.

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

9 A. Under the PCA Mechanism, new resources with a term *less* than or equal to two
10 years are included in allowable PCA costs. The prudence of such resources is
11 determined in the Commission's review of the annual PCA true-up. On the other
12 hand, the power costs related to a new electric resource with a term of *greater* than
13 two years are included in allowable PCA costs through a bridge mechanism, known
14 as PCA Exhibit G, "New Resource Adjustment". Exhibit G reduces the variable
15 costs of the new resources to the lower of actual unit cost or the baseline rate until
16 the prudence of such resources can be reviewed and approved in a power cost only
17 or general rate case.

18 **Q. Were there new resources that triggered the PCA Exhibit G calculation during**
19 **the PCA Period 10?**

20 A. No. The PCA bridge mechanism is PCA Exhibit G, "New Resource Adjustment"
21 and provides a calculation to reduce the actual costs allowed in the PCA mechanism
22 for new resources with terms greater than two years that are not yet recovered in

1 rates. PSE had no new resources during PCA Period 10 that triggered the PCA
2 Exhibit G calculation.

3 III. RENEWABLE ENERGY CREDITS

4 Q. What is a Renewable Energy Credit?

5 A. A Renewable Energy Credit ("REC") represents the environmental attributes of
6 renewable energy generation in the form of a marketable commodity. PSE receives
7 RECs from its owned and contracted renewable energy resources such as PSE's
8 Hopkins Ridge and Wild Horse wind projects, as well as its contracted portion of
9 the Klondike III wind project under a Power Purchase Agreement ("PPA") with
10 Iberdrola Renewables. Generally, RECs may be traded as a "bundled" product
11 where the electricity and environmental attributes are sold together or as an
12 "unbundled", or REC-only, product where only the environmental attributes are
13 sold.

14 Q. Did PSE have any REC transactions during the PCA Period 10?

15 A. Yes. In 2009, PSE entered into contracts with third-parties for the sale of its surplus
16 RECs (e.g. in excess of PSE's near-term renewable targets). These REC sales were
17 bundled with electricity and sourced from PSE's portfolio of renewable resources.
18 During 2011, PSE delivered a portion of these RECs to the third-parties it
19 contracted with in 2009. PSE's accounting for the revenues created by the sale of
20 RECs was determined in PSE's Docket UE-070725 and was applicable during the
21 entire PCA 10 period.

1 **Q. Do PSE's bundled REC transactions impact power costs?**

2 A. No, PSE's bundled REC sales do not affect total power costs. Under these
3 agreements, PSE sells firm physical market-sourced power at the Mid-Columbia
4 ("Mid-C") hub in quantities equivalent to the Renewables Portfolio Standard-
5 eligible product quantities defined in the contracts. Third-party buyers are
6 obligated to pay the contractual on- or off-peak Mid-C index price, as applicable
7 under their contract, as published by the Intercontinental Exchange, Inc. ("ICE") for
8 the power, plus a fixed price for each REC. PSE then purchases the equivalent
9 physical power obligation to settle at the contractual daily Mid-C index price as
10 published by the ICE. Any difference between the cost of the purchased power and
11 the proceeds from the sale of the power is removed from power costs and deferred
12 in FERC Account 254. As a result, the cost of the physical power sold equals the
13 cost of the power purchased, resulting in a zero impact to power costs.

14 **Q. Has PSE entered into any other REC-related agreements?**

15 A. Yes. In February 2011, PSE entered into an agreement with the King County Solid
16 Waste division of King County, Washington ("King County") to purchase all of the
17 emission credits associated with the pipeline quality gas produced by the Cedar
18 Hills Regional Landfill facility ("Cedar Hills"). In exchange, King County will
19 receive a share of the net proceeds from the sale of qualified renewable gas or RECs
20 produced by the Cedar Hills gas when used to generate electricity. This agreement,
21 combined with the agreement to purchase the pipeline quality gas from Bio Energy
22 (Washington), LLC ("Bio Energy"), entitles PSE to all the renewable attributes

1 associated with the landfill gas generated by Cedar Hills.

2 In late 2010, after PSE examined its landfill gas position, potential products and
3 potential counterparties, PSE determined the landfill gas renewable attributes were
4 more valuable transacted as delivered biogas (physical landfill gas plus renewable
5 attributes) - as compared to a generated REC. In February 2011, following the
6 effectiveness of the King County/PSE emissions agreement, PSE re-engaged
7 counterparties and conducted a competitive bid process for the biogas, rewarding a
8 contract for the biogas to the high bidder in June 2011.

9 Since then, PSE has entered into four short-term agreements with this third-party
10 for the sale of biogas. In addition, PSE is evaluating its other options for this
11 product and is in discussions with other third-parties for both short- and long-term
12 arrangements.

13 **Q. How does PSE account for the pipeline quality gas generated by Cedar Hills?**

14 A. In October 2008, PSE arranged to purchase all of the pipeline quality gas supply
15 produced from Cedar Hills under a separate agreement with Bio Energy. Prior to
16 the February 11, 2011 agreement with King County, the cost of the Cedar Hills
17 landfill gas was a fuel expense. Beginning on the date PSE had the ability to
18 monetize the renewable attributes of the landfill gas - February 11, 2011 - PSE
19 tracked the Cedar Hills landfill gas in a separate gas inventory account. When this
20 gas is sold, PSE accounts for it as a sale of excess gas by crediting FERC 456, other
21 electric revenues, with the sale price of the gas sold.

1 **Q. Will the sales of the Cedar Hills emission credits affect power costs?**

2 A. No. The revenues generated from the sale of the emission credits are tracked
3 separately and deferred in the deferred REC revenue 254 account for future
4 customer credit. Payments to King County for their share of the net proceeds will
5 reduce the deferred REC revenues.

6 **IV. PCA PERIOD 10 POWER COSTS**

7 **A. PCA Period 10 Power Resources**

8 **Q. What are the changes to long-term electric supply resources that were not**
9 **included in the baseline rate during PCA Period 10?**

10 A. The baseline rates in effect during the PCA Period 10 reflect the power portfolio
11 from PSE's WUTC Docket No. UE-090704 ("2009 GRC"). There were a number
12 of changes to PSE's portfolio that were reflected in the PCA Period 10 power costs
13 that were different than PSE's 2009 GRC power portfolio. Specifically, the PCA
14 Period 10 power costs included:

- 15 (1) Energy from the 4-year winter on-peak PPA with Barclays
16 Bank PLC for an additional 75 MW of winter-only capacity
17 effective November 1, 2011 which was deemed prudent in
18 PSE's 2009 GRC but was not included in the baseline rate
19 effective April 8, 2010 as the contract began after the 2009
20 GRC rate year ended;
- 21 (2) The new twenty-year contract with the Public Utility District
22 No. 1 of Chelan County, Washington ("Chelan PUD") that the
23 Commission issued a prudence determination in PSE's 2006
24 general rate case, Docket Nos. UE-060266 & UG-060267
25 (consolidated) (the "2006 GRC") for 25 percent of the Rocky
26 Reach Hydroelectric Project ("Rocky Reach") output effective
27 November 1, 2011. This 25 percent share is a reduction from
28 the 38.9 percent share contract which expired on October 31,

1 2011 and reduced PSE's capacity to 320 MW (as compared to
2 the previous contracted 498 MW). (Note that the contract
3 share reduction for the Rock Island 1&2 Hydroelectric Project
4 is not effective until July 1, 2012);

5 (3) A lower share of net generation and costs under the Mid-C
6 contract terms with Public Utility District No. 2 of Grant
7 County, Washington ("Grant PUD"). Specifically, PSE's share
8 of the output from the Wanapum Development and Priest
9 Rapids Development Hydroelectric Projects decreased from
10 those included in the 2009 GRC (1.29 percent and 0.64 percent
11 in 2010 and 2011, respectively), to 0.75 percent of the
12 combined Priest Rapids Hydroelectric Project projection for
13 the calendar 2011 PCA 10 period;

14 (4) Contracts executed or extended under PSE's Schedule 91 tariff.
15 The following Schedule 91 contracts were executed or
16 extended for PCA Period 10:

- 17 a. an extension of the PPA with Port Townsend Paper
18 Corporation for the output of a 0.375 MW hydro
19 generator;
- 20 b. a PPA with Black Creek Hydro, Inc. effective March
21 2011 for the output of a 4.2 MW hydroelectric system;
- 22 c. a PPA with Smith Creek Hydro LLC effective April
23 2011 for the output of two hydroelectric turbines with a
24 combined capacity of 0.12 MW;
- 25 d. a PPA with Van Dyk-S Holsteins LLC effective June
26 2011 for the output of a .472 MW generator powered
27 by the biogas from a dairy manure anaerobic digester;
- 28 e. a PPA with First Up! Knudson Wind Turbine #1 LLC
29 effective June 2011 for the output from a 0.108 MW
30 wind project;
- 31 f. a PPA with Island Community Solar, LLC effective
32 July 2011 for the output from a 0.075 MW solar
33 photovoltaic system; and
- 34 g. a PPA with Cascade Community Wind LLC effective
35 September 2011 for the output from Three Bar G Wind
36 Turbines #1-3 with a combined capacity of 1.395 MW.

37 (5) The expiration of:

- 38 a. PSE's contract with Northwestern Energy for 97 MW of
39 capacity on December 28, 2010;
- 40 b. the Priest Rapids Displacement Product, an approximately

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29 MW block of low cost power purchased under PSE's contract with Grant PUD on September 30, 2011;

- c. PSE's 245 MW capacity contract with Tenaska Washington Partners, LP on December 31, 2011;
- d. PSE's 145 MW capacity contract with March Point Cogeneration Company on December 31, 2011;
- e. PSE's 22.9 MW capacity Municipal Steam Waste contract with the City of Spokane on December 31, 2011; and
- f. PSE's agreement with Occidental Energy Marketing, Inc. for gas transportation between the Rockies region and Sumas through June 30, 2011 and the assumed replacement contract.

(6) Zero generation from PSE's Snoqualmie Falls Hydroelectric Project due to the redevelopment of Powerhouse #1 (12 MW capacity) and Powerhouse #2 (34 MW capacity) for the entire PCA 10 period as compared to three months of generation (55,681 MWhs) included in the 2009 GRC baseline rate; and

- (7) New long-term gas for power pipeline capacity for:
- a. 28,928 MMBtu per day of gas for power pipeline capacity from Stanfield to Deer Island, Jackson Prairie and Bellingham effective April 1, 2011 through March 31, 2025; and
 - b. 25,853 MMBtu per day of Westcoast pipeline deliverability (released from BNP Paribas) between Station 2 and Huntingdon (Sumas) effective April 1, 2010 through October 2018.

Q. Did PSE acquire any new resources during PCA Period 10 with a term of less than or equal to two years?

A. Yes. PSE acquired such resources in connection with short- and intermediate-term off-system physical or financial purchases and sales of power and/or 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

1 contracts. Such balancing transactions are made in response to changes in load or
2 resource availability as well as changes in market heat rates, which guide decisions
3 whether to dispatch gas-fired generation or to buy or sell power versus natural gas
4 for power. Such transactions include intermediate term transactions entered into
5 pursuant to PSE's programmatic portfolio hedging efforts.

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

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

9 A. These transactions were undertaken within a comprehensive portfolio and risk
10 management system of organizational structure, technological tools, and human
11 resources designed to allow PSE to (1) deliver reliable energy when its customers
12 demand it; (2) serve its customers while mitigating price volatility; and (3) enhance
13 the value of PSE's energy resources.

14 PSE has had organizational structures, policies and overarching strategies in place
15 for many years to provide oversight and control of energy portfolio management
16 activities, many of which must be undertaken on an hourly and daily basis by PSE's
17 experienced energy traders. PSE also uses modeling tools that assist in projecting
18 whether its power and gas portfolios will be surplus or deficit in future months.

19 PSE uses these tools to develop and implement hedging strategies to reduce the cost
20 risks associated with portfolio volatility.

21 The following section of my testimony first provides a description of these systems
22 and tools. I then illustrate their application to PCA Period 10 by describing actual

1 hedging strategy decisions and their execution undertaken by PSE with respect to
2 its power supply for a sample month, August 2011. See Exhibit No. ____ (DEM-3C).

3 **B. PSE's Management of its Power Portfolio and Related Fuel Supply for**
4 **PCA Period 10**

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

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

8 A. PSE's Energy Portfolio Management function ("EPM department") includes certain
9 employees from the Energy Supply & Planning department ("ESPD") and the
10 Structuring, Asset Optimization and Analytics department. The EPM Department
11 is composed of energy market analysts, quantitative analysts, seasoned energy
12 traders and other professionals. The EPM department is responsible for identifying,
13 quantifying, monitoring and recommending risk management strategies for PSE.
14 The EPM department performs these tasks and manages PSE's short- and medium-
15 term portfolios. The ESPD is led by the Senior Vice President, Energy Operations.
16 The Structuring, Asset Optimization and Analytics department is led by the Vice
17 President Finance and Treasurer.

18 The Energy Risk Control ("ERC") department includes the Credit Risk
19 Management group, and is responsible for providing risk control oversight. The
20 ERC department is led by the Vice President Finance and Treasurer.

21 PSE's Energy Management Committee ("EMC") – composed of five senior PSE
22 officers – oversees the activities performed by the EPM department. The EMC is

1 responsible for providing oversight and direction on all portfolio risk issues in
2 addition to approving long-term resource contracts and acquisitions. The EMC
3 provides policy-level and strategic direction on a regular basis, reviews position
4 reports, sets risk exposure limits, reviews proposed risk management strategies, and
5 approves policy, procedures and strategies for implementation by PSE staff.

6 In addition, PSE's Board of Directors provides executive oversight of these areas
7 through the Audit Committee.

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

9 A. With respect to hedging strategies for specific time periods or quantities of energy,
10 the EMC has approved a Programmatic Hedging Strategy. The original
11 programmatic hedging strategy was approved by the EMC on July 22, 2004, with a
12 PSE staff transactional purview of [REDACTED]. The term of the EMC approved
13 programmatic hedge strategy originally consisted of the last [REDACTED] of the [REDACTED]
14 [REDACTED] purview ("Programmatically Managed Hedge"), but was reduced to [REDACTED]
15 [REDACTED] in early 2006. The balance of the [REDACTED] purview were actively
16 managed ("Actively Managed Hedge") in accordance with the EMC approved
17 Energy Supply Hedging and Optimization Procedures Manual ("Procedures
18 Manual"). In October 2007, PSE extended department staff's transactional purview
19 from [REDACTED] to [REDACTED]. At that time, the balance of the current month plus the first
20 full [REDACTED] became the Actively Managed Hedge in accordance with the
21 Procedures Manual and the latter [REDACTED] became the Programmatically
22 Managed Hedge in accordance with the EMC approved strategy. EPM department

1 staff utilize the Programmatically Managed Hedge to systematically reduce PSE's
2 net power portfolio exposure beginning [REDACTED] in advance of the month in which
3 the power will be needed to serve PSE's load. This process is described in greater
4 detail below and in Exhibit No. ___(DEM-3C), which also steps through a sample
5 month, August 2011. Such exposure reduction is subject to minimum and
6 maximum monthly limits to reduce timing and market risks associated with hedging
7 activities.

8 Pursuant to the hedging strategies in effect during the PCA Period 10, by at least [REDACTED]
9 [REDACTED] prior to delivery, the bulk of the hedging strategies and transactions have
10 been made, leaving primarily only balancing transactions needed to respond to
11 changes in market heat rates, load, hydro conditions, unit assumptions and other
12 portfolio changes. Decisions about hedges for delivery during the Actively
13 Managed Hedge are made by EPM department staff, within limits set out in PSE's
14 Procedures Manual.

15 **Q. How does PSE integrate hedging activities into its provision of electric power**
16 **to customers?**

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

22 To model a variety of scenarios regarding PSE's gas-fired generation, the risk

1 system takes into account each plant's individual operating characteristics,
2 including: unit efficiency, start-up costs, variable operating costs, minimum run
3 times, planned and unplanned outages, and unit availability. The risk system
4 performs simulations of different market conditions and various outages in order to
5 develop an estimate of the gas volumes required to produce a volume of power.
6 The plants are modeled on an hourly basis and the information is aggregated into
7 daily and monthly time frames for purposes of developing a forward-looking
8 position. The risk system incorporates information about hedges that PSE staff has
9 already executed to model whether the portfolio is surplus or deficit. The risk
10 system incorporates the inter-relationship between gas and power prices in
11 developing its probabilistic gas and power positions. In different market scenarios,
12 PSE's gas or power requirements will change. The reason for this is twofold. First,
13 the plants have different operating efficiencies (known as "heat rates") and become
14 economic to dispatch at different price differentials between power and gas.
15 Second, the forward market prices for power and gas change frequently and the
16 price relationship between power and gas, known as the "implied market heat rate",
17 changes as well. At certain implied market heat rates, PSE will expect to run each
18 plant at an expected rate, and the total of all the plant requirements can be
19 calculated. But if market conditions change, PSE will expect to adjust its gas and
20 power purchases and sales in order to serve load with the most economic resources.
21 For example, it may be more economic to purchase power than to purchase gas to
22 generate the power PSE needs to serve its load.

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

2 A. The risk system generates a probabilistic volumetric position report, comprised of
3 250 scenarios, for on- and off-peak power and gas for power. The position report
4 shows, for each of the months following the date of the report, the resource types in
5 PSE's power position grouped by: short-term purchase and sale transactions, long-
6 term contracts, Combustion Turbines ("CT") grouped by heat rate efficiency of the
7 facilities, Non Utility Generators/Qualifying Facilities ("NUGs/QFs"), Coal Plants,
8 Wind and Hydro (both PSE-owned and Mid-C contracts). Based on this volumetric
9 position for each month, the risk system also generates the potential exposure
10 associated with the "open" positions (defined as any net surplus or deficit amount as
11 compared to the load demand). *See* Exhibit No. ___(DEM-4C).

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

14 A. Once PSE's aggregated energy position and net exposure are defined for a
15 particular period, the EPM department evaluates and develops risk management
16 strategy proposals and/or executes transactions around the purchase or sale of gas or
17 power, as appropriate, to move toward a balanced position and reduced exposure.
18 Execution entails entering into specific transactions with approved counterparties,
19 approved instruments, executed master agreements and available credit.

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

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

10 **Q. Does Energy Portfolio Management staff implement the Programmatic**
11 **Hedging Plan by relying only on the net exposure?**

12 A. No. The net exposure drives transactions only to the point of showing whether
13 PSE's exposure is within the maximum and minimum monthly limits of the plan.
14 EPM department staff must then make use of market fundamentals, water supply
15 and weather forecasts that impact the wholesale electric and gas markets to decide
16 whether to press toward the maximum or minimum monthly limits, or somewhere
17 in between. EPM department staff also determines when and how to execute such
18 transactions to maintain each months net exposure reduction within the maximum
19 and minimum limits.

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1 **Q. How does PSE's staff develop a view of appropriate hedging strategies for the**
2 **power portfolio?**

3 A. The EPM department utilizes a wide set of tools and sources of information to help
4 them make informed decisions about dispatching plants, purchasing fuel and
5 executing hedges approved by the EMC. They also hold meetings each month so
6 that the teams can review operational events, discuss market trends and
7 fundamentals and review supply and demand information. Within this context, the
8 teams work together to understand the exposures in the portfolio and discuss where
9 hedging priorities occur. Underlying all this teamwork is an EPM department staff
10 with years of experience in energy trading, optimization and risk management.

11 **Q. What types of information does the Energy Portfolio Management staff**
12 **consider?**

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

20 EPM department staff also receive real-time information from a variety of sources
21 such as: McGraw Hill (Gas Daily, Megawatt Daily), Future Source;
22 Intercontinental Exchange (live price data); live broker lines where current

1 transactions are communicated through a speaker system, and other tools. The EPM
2 department also has instantaneous data coming from PSE's systems operations staff
3 so they can view load and generation dispatch data on a real-time basis.

4 In addition to using such information and processes to implement the current
5 Programmatic Hedging Plan, the EPM department also uses such information to
6 develop recommendations to the EMC regarding potential changes to PSE's
7 overarching hedging strategies or to recommend transactions that do not fall within
8 those strategies.

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

10 A. Yes. PSE also uses a counterparty credit risk management system to assist the
11 Credit Risk Management group and the EPM department staff in evaluating credit
12 issues associated with potential transactions with respect to credit issues. With this
13 tool, staff can review data including:

- 14 • Moody's and S&P rating of the entity;
- 15 • applicable information about the parent of the entity;
- 16 • amount of parent guarantee credit provided to PSE, if applicable;
- 17 • the entity's amounts payable and receivable;
- 18 • the aggregate mark to market exposure of all open forward
19 transactions with the entity (the dollar value of the difference
20 between the original contract price and current market price);
- 21 • the credit limit assigned to the entity;
- 22 • the existence of netting terms; and
- 23 • FAS 149 designation for accounting purposes.

24 This information is gathered and calculated daily.

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

3 A. Many years ago, PSE moved from a more "discretionary" model of making hedging
4 decisions to a more "programmatic" approach to hedging. The preceding dollar-
5 cost averaging strategy established a disciplined approach to purchasing a defined
6 volume of gas or power on a monthly basis. In applying this strategy, PSE typically
7 established plans to purchase hedges for specific forward time periods, with the
8 goal of purchasing a defined amount of power and gas in order to ratably reduce the
9 deficit positions by a small amount each month.

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

18 In May 2004, during PCA Period 2, PSE began to employ a metric called Margin at
19 Risk ("MaR"), which measures risk reduction as a result of incremental hedging.
20 *See Exhibit No. ___(DEM-5C).* PSE has incorporated the MaR concept into the
21 evaluation process for hedge strategies to measure risk reduction for various
22 alternatives. A series of hedge strategies (transaction types) are run through the

1 portfolio, providing a table of how much risk reduction is gained by month and by
2 strategy. The MaR concept assists with deciding how to allocate dollars in a credit-
3 constrained environment, thus providing an additional tool for choosing between
4 available commodities. See Exhibit No. ___(DEM-6C).

5 In July 2004, the EMC approved a continuation of a dollar cost averaging strategy
6 (hedging on a regular schedule over a lengthy period, in order to capture lower as
7 well as higher prices during periods of volatility) informed by MaR. However, the
8 EMC directed that PSE staff monitor and more actively address the exposure
9 associated with PSE's power portfolio position [REDACTED] ahead of the time the
10 power would be needed. On January 7, 2006, the Rolling [REDACTED] Hedging Plan
11 was amended to be a Rolling [REDACTED] Hedge to guide hedging decisions for the [REDACTED]
12 to [REDACTED] time frame. In October 2007, this hedging plan was extended and now
13 covers the [REDACTED] to [REDACTED] time frame ("Programmatically Managed Hedge"). This
14 hedging plan increased staff's ability to react to position changes as a result of
15 forecast customer demand, stream-flow variations, forced thermal plant outages,
16 and changing market conditions.

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

21 **Q. How does the Programmatically Managed Hedge Plan work?**

22 A. As mentioned above, in October 2007, PSE extended staff's transactional purview

1 from [REDACTED] to [REDACTED]. At that time, the first [REDACTED] became the Actively
2 Managed Hedge in accordance with the Procedures Manual and the remaining [REDACTED]
3 [REDACTED] became the "Programmatically Managed Hedge" in accordance with the
4 EMC approved strategy. The revised strategy retained many of the same features as
5 the previous hedging strategy. These include

- 6 (i) a required ratable reduction of monthly commodity exposure
7 removed each month;
- 8 (ii) the volume of monthly hedging and intra-month timing for hedging
9 is informed by market fundamentals; and
- 10 (iii) hedging targets are established on the basis of the minimum or
11 maximum amount of commodity exposure allowed under the EMC
12 approved strategy.

13 The revised plan requires that on or before [REDACTED] ahead of delivery, the bulk of
14 the hedging strategies and transactions have been made per this programmatic plan.
15 These revisions enable PSE to monitor and more actively address the exposure
16 associated with PSE's power portfolio position [REDACTED] ahead of the time the
17 power would be needed to serve load.

18 **Q. Why did PSE extend its hedging strategies?**

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

**REDACTED
VERSION**

1 **2. Application of PSE’s Risk Management System to PCA Period**
2 **10 Power Costs**

3 **Q. Would you provide some examples of how PSE applied the risk management**
4 **systems, tools and strategies described above with respect to PCA Period 10**
5 **power supply and costs?**

6 A. Yes. Take, for example, PSE’s energy requirements for August 2011. Beginning in
7 ██████████, PSE’s EPM staff began to actively reduce spot market price
8 exposure for the delivery period August 2011. From ██████████ through ██████
9 ██████, on a monthly or bi-monthly basis, EPM department staff developed strategies
10 to reduce PSE’s exposure with respect to its electric supply needs for August 2011.
11 Such strategies reflected updated Position and Exposure Reports generated by
12 PSE’s risk system, market heat rates, hydro conditions and weather fundamentals,
13 and other available information. In accordance with the EMC approved
14 Programmatic Hedging Plan and within the limits described therein, PSE staff
15 executed these strategies by entering into hedging transactions. EPM department
16 staff can make recommendations to depart from this plan, but execution of such
17 hedges is subject to EMC approval. With respect to the August 2011 power supply,
18 EPM department staff did not make any such recommendations, but instead kept the
19 EMC informed of its analyses and activities. See Exhibit No. ___(DEM-3C) for
20 discussion of the hedges transacted for August 2011, which are presented in Exhibit
21 Nos. ___(DEM-7C) and ___(DEM-8C).
22 Beginning in ██████████, the power supply for August 2011 rolled into staff’s
23 newly extended ██████████ Programmatic Managed Hedge purview. Beginning

1 in [REDACTED], the power supply for August 2011 rolled into staff's Actively
2 Managed Hedge - at which point staff continued to analyze PSE's position for
3 August 2011 on a daily basis and, based on market conditions and other information
4 available to them at the time, took actions to reduce PSE's exposure under the
5 authority and limits of the Procedures Manual.

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

10 **Q. Are the activities described in Exhibit No. ___(DEM-3C) the only risk**
11 **management activities that PSE undertook for PCA Period 10?**

12 A. No. Similar activities were undertaken with respect to managing PSE's portfolio
13 and exposure for the entire PCA Period 10. Some of that information is apparent
14 from the materials presented in Exhibit No. ___(DEM-3C) and the other exhibits
15 filed with my Prefiled Direct Testimony. However, describing and documenting all
16 of the details of such activities for the entire PCA Period 10 would be a
17 monumental task and are considered to be outside the scope of this testimony.

18 **Q. How did PSE manage gas supply for Tenaska during PCA Period 10?**

19 A. PSE managed gas supply for Tenapska as part of its overall power portfolio by
20 applying the risk management tools and systems described above. PSE ultimately
21 hedged the financial exposure associated with its power portfolio taking into

1 account the probabilistic dispatch rate of Tenaska and other plants. This means that
2 PSE hedged fuel supply in the financial gas derivatives market over time as
3 necessary to reduce open position exposure and ultimately balance the position on a
4 probabilistic basis. The physical fuel requirement was then acquired in the monthly
5 or daily spot market, whichever was determined to be most advantageous at the
6 time. PSE also included in the position the exposure associated with Tenaska
7 displacement. The term of the exposure related to Tenaska displacement is
8 modeled by PSE's risk system and is factored into PSE's overall position used for
9 the hedging program. The risk system creates a power and gas position related to
10 the displacement that makes the position shorter gas and longer power (i.e. longer
11 heat rate) by fifty percent of the displaced volume. As noted above, PSE's contract
12 with the Tenaska Washington Partners, LP expired at the end of PCA Period 10, on
13 December 31, 2011.

14 **3. Winter Peaking Contracts**

15 **Q. Why does PSE enter into winter peaking contracts?**

16 **A.** Winter peaking contracts are procured so that PSE will be able to reliably serve
17 high loads that occur during an extreme winter peak event by locking in firm
18 physical supply.

19 **Q. How did PSE approach the decisions of whether and how to enter into winter**
20 **peaking contracts for the winter months of calendar 2011?**

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

1 management systems and procedures.

2 PSE specifically considered how it should plan for and execute contracts to provide
3 peaking capacity or related hedges. As part of that assessment, PSE considered the
4 effectiveness of entering into various call options that were available in the market
5 versus "self-insuring" against extreme winter peak events. PSE ultimately decided
6 that it would purchase several winter on-peak power index transactions to ensure
7 firm physical power supply during the winter peaking hours.

8 **C. PSE's PCA Period 10 Actual Power Costs**

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

10 A. During PCA Period 10, PSE's rates have over-recovered actual power costs by
11 \$34.8 million. PSE customers will share \$7.4 million of this over-recovery and
12 PSE will retain the remaining \$27.4 million.

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

14 A. The actual costs of power delivered to PSE's system will always differ from those
15 set in rates as they reflect the actual outcome of power costs volatilities, which
16 include, for example,:

- 17 (i) streamflow variation affecting the supply of hydroelectric
18 generation;
- 19 (ii) weather uncertainty affecting power usage;
- 20 (iii) variations in market conditions resulting in changes to
21 wholesale gas and electric prices;
- 22 (iv) risk of forced generation outages;

1 (v) variability of wind generation; and

2 (vii) transmission and transportation constraints.

3 Although power costs set in rates are estimated “as closely as possible to costs that
4 are reasonably expected to be actually incurred,¹” they are still forecasts of future
5 events, which are further limited by regulatory normalizing assumptions.

6 Specifically, current ratemaking normalizes the power cost volatilities by
7 employing:

8 (i) a 50-year hydro data set to determine hydro generation²;

9 (ii) a weather normalized load forecast;

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

11 (iv) historical average forced outage rates; and

12 (v) forecast average wind generation.

13 **Q. What caused the difference during PCA Period 10 between PSE’s actual power**
14 **costs and power costs recovered in rates?**

15 A. PSE's \$34.8 million over-recovery of amounts recovered through the Power Cost
16 Baseline Rate during the calendar year 2011 PCA Period 10 were due to several
17 factors. During this time, PSE benefited from:

18 (1) higher Mid-Columbia ("Mid-C") hydro generation (due to 125 percent of
19 normal runoff at Grand Coulee during the January - July 2011 period

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

² PSE has requested to use an average of 70-years Mid-C streamflow history in its 2011 general rate case, Docket No. UE-111048.

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where normal is considered to be the 30 year average from 1971 to 2000. See Exhibit No. ___(DEM-9));

- (2) lower market power prices;
- (3) revenues of \$3.0 million associated with PSE’s ability, effective March 2010, to reassign BPA transmission on a short-term basis; and
- (4) replacing with lower cost market power purchases the power associated with the 97MW capacity Northwestern Energy contract, which expired December 29, 2010, but remained in rates at an average cost of \$59.91³ per MWh.

PSE’s Mid-C hydro generation during calendar year 2011 was 408,813 MWhs above the 50-year average generation included in the 2009 GRC due to 125 percent of normal runoff conditions. However, the aforementioned increase in hydro generation compared to the 2009 GRC would have been even greater had it not been for the decline in PSE’s share of the output from Rocky Reach hydroelectric project. On November 1, 2011, PSE’s share of Rocky Reach declined from 38.9% to 25% due to the beginning of the new contract with Public Utility District No. 1 of Chelan County. This decline in Mid-C hydro capacity of about 178 MW was not included in the 2009 GRC as it was outside of the rate year which ended March 31, 2011.

³ PSE’s 2009 GRC included 598,047 MWhs of power under the Northwestern Energy contract at a cost of \$35.8 million; an average cost of \$59.91 per MWh.

1 Actual Mid-C market prices in 2011 were well below the prices included in the
 2 2009 GRC baseline rate. The average flat Mid-C price included in the 2009 GRC
 3 baseline rate was \$42.49 per MWh as compared to the actual average flat Mid-C
 4 price for calendar year 2011 of \$22.08 per MWh. This reduction to Mid-C prices
 5 resulted in a decrease to the average cost of market purchases compared to rates as
 6 shown in the table below. While the average price for market sales also declined,
 7 the impact of purchases more than offset the sales as PSE was a net purchaser of
 8 power during 2011. In fact, the purchased volume (in MWhs) for 2011 was more
 9 than double the volume of purchases in the 2009 GRC power costs, primarily
 10 because the drop in Mid-C market prices, which led to a decline in market heat
 11 rates, made it more economical to displace both PSE's gas fired units and Colstrip
 12 units more frequently and replace the power with lower-priced market purchases.
 13 The table below compares PSE's actual 2011 net market transactions – purchases
 14 and sales – to those included in PSE's 2009 GRC.

		Actual CY 2011	2009 GRC Apr 10-Mar 11	Change
Market Purchases	\$ in 000s	\$276,283	\$195,703	\$80,581
	MWh	8,556,726	3,642,825	4,913,901
	\$ / MWh	\$32.29	\$53.72	(\$21.43)
Market Sales	\$ in 000s	(\$43,615)	(\$28,648)	(\$14,967)
	MWh	(1,811,328)	(718,914)	(1,092,414)
	\$ / MWh	\$24.08	\$39.85	(\$15.77)

15
 16 The 2009 GRC power costs included 9 months of the Northwestern Energy contract
 17 or 598,047 MWhs of generation. Therefore, although the Northwestern Energy

1 (“NWE”) contract expired December 29, 2010, costs associated with it were still
2 included in the baseline rate during calendar year 2011. Given that market prices
3 for 2011 were well below the average NWE contract price of \$59.91 (including
4 fixed costs), PCA Period 10 power costs declined as the higher cost NWE
5 generation was replaced from replacing the contract generation with Mid-C market
6 purchases at a lower price.

7 **Q. Are PSE’s PCA Period 10 power costs net of any accounting adjustments?**

8 A. Yes, there were two adjustments made to credit, or reduce, the power costs by a
9 total of \$3.76 million during PCA Period 10. Due to the PCA Mechanism’s true-up
10 methodology, \$3.31 million of this credit to power costs was removed from the
11 PCA Period 10 power costs used to calculate the deferral and were included in the
12 power costs of the appropriate prior PCA periods. These adjustments are noted
13 below and are also discussed in greater detail in Mr. John Story’s Exhibit

14 No. ___(JHS-1T):

- 15 1. A \$2.11 million credit was posted to PCA Period 10 power costs for a
16 financial settlement reached with Bonneville Power Administration to
17 reimburse PSE for a metering error which resulted in PSE simultaneously
18 paying for station service and self-providing station service for the
19 Goldendale generating facility when it was generating. As this settlement
20 related to PCA periods 8 through 10, the portion of the credit associated
21 with prior PCA periods - \$2.06 million - was removed from the PCA Period
22 10 power costs and allocated to the appropriate PCA periods, as required
23 under the PCA Mechanism true-up methodology.
- 24 2. In September 2011, PSE received a \$1.65 million credit from the Canadian
25 government for taxes paid on non-core gas pipeline transportation costs
26 incurred between April 2008 through March 2011 or PCA periods 7 through
27 10. As the credit was over \$1.0 million and partially related to prior PCA
28 periods, the appropriate amount of the credit - \$1.25 million - was removed
29 from PCA period 10 power costs and PCA periods 7 through 9 were

1 restated, as required under the PCA Mechanism true-up methodology.

2 **Q. Are there any other entries included in PCA Period 10 power costs that were**
3 **not subject to the PCA Mechanism true up methodology that you would like to**
4 **discuss.**

5 A. Yes. PCA period 10 power costs include an entry that was recorded to reduce
6 power costs by \$0.94 million as a result of an under recovery of the costs associated
7 with the Tenaska regulatory asset that were moved out of base rates in the 2009
8 GRC and put into a separate tariff rider, Electric Tariff Schedule 133. The under
9 collected balance will be collected and amortized during calendar year 2012
10 pursuant to WUTC Docket No. UE-120137. Additional discussion of this item is
11 included in the prefiled direct testimony of Mr. John H. Story, Exhibit
12 No. ___(JHS-1T).

13 **V. CONCLUSION**

14 **Q. Do you believe that PSE has met the Commission's prudence standard with**
15 **respect to its power costs during PCA Period 10?**

16 A. Yes; PSE met the Commission's prudence standard for the PCA Period 10 power
17 costs because PSE's management of its power costs during PCA Period 10 was
18 reasonable. PSE has structures and processes in place to formulate strategies for
19 controlling power costs and executed those strategies, taking into account
20 information and variables associated with managing a complex resource portfolio
21 within a dynamic market environment.

1 **Q. Does that conclude your testimony?**

2 A. Yes, it does.