EXHIBIT NO. ___(DEM-1CT)
DOCKET NO. UE-11____
PCA 9 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 2011 Power Cost Adjustment Mechanism Report**	**Docket No. UE-11____**

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

REDACTED VERSION

MARCH 31, 2011

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF DAVID E. MILLS

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF DAVID E. MILLS

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 N.E. Fourth Street, Bellevue, Washington, 98004-5591. I am the Director, Energy Supply and Planning 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 Director, Energy Supply & Planning for PSE?

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

Q. Please summarize the contents of your testimony.

A. I first provide some brief background information regarding the Power Cost Adjustment ("PCA") Mechanism and how it addresses the volatility of PSE's power costs. I then describe the changes in power resources and efforts undertaken by PSE to manage, control and moderate its power costs during the period that began on January 1, 2010 and ended on December 31, 2010 ("PCA Period 9"). Finally, I compare PSE's actual power costs for PCA Period 9 to its baseline power cost rates that were in effect for PCA Period 9. The baseline power cost rate pursuant to PSE's 2007 general rate case, WUTC Docket No. UE-072300 ("2007 GRC"), was in effect through April 7, 2010. The baseline power cost rate from PSE's 2009 general rate case, WUTC Docket No. UE-072300 ("2009 GRC"), has been in effect since April 8, 2010.

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 potential volatility, uncertainty in the wholesale energy markets and PSE's need to add resources to meet its load obligations, the parties who participated in the PCA settlement collaborative in PSE's 2000-2001 general rate case agreed to a negotiated PCA Mechanism. The Commission approved the PCA Mechanism in its Twelfth Supplemental Order in Docket Nos. UE-011570 and UG-011571. The PCA Mechanism became effective July 1, 2002.

Q. Please describe why PSE's 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 constraints. All of these have an impact on load and resource volatility, which PSE may balance with wholesale market purchases and sales.

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 5 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 "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 PCA Period 9, PSE's actual power costs were $38.3 million above the amounts recovered through the power cost baseline rate and are discussed in more detail in section IV.C of my testimony. See the Prefiled Direct Testimony of Mr. John H. Story, Exhibit No. ___(JHS-1T), for further information and discussion and the PCA Annual Report reflecting the $38.3 million power cost variance.

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. On the other hand, the power costs related to a new electric resource with a term of *greater* than two years are included in allowable PCA costs through a bridge mechanism, known as PCA Exhibit G, "New Resource Adjustment". Exhibit G reduces the variable costs of the new resources to the lower of actual unit cost or 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 9?

A. Yes. I discuss these new resources later in my testimony. In addition, Mr. John Story discusses the methodology for calculating the PCA Exhibit G adjustment and its impact on PCA Period 9 in more detail in his Prefiled Direct Testimony, Exhibit No. ___(JHS-1T).

III. RENEWABLE ENERGY CREDITS

Q. What are Renewable Energy Credits?

A. Renewable Energy Credits ("RECs") represent the monetary value of the environmental attributes of power generation from renewable energy facilities. PSE receives RECs from electricity generated from its owned and contracted wind or other renewable energy resources such as the Hopkins Ridge, Wild Horse and Klondike wind facilities. In general, RECs may be traded as a bundled product where the electricity and environmental attributes are sold together or as an unbundled product where only the environmental attribute is sold.

Q. Did PSE have any bundled REC transactions during the PCA Period 9?

A. Yes. During 2010, PSE sold bundled REC under contracts PSE had transacted with third parties in 2009 to monetize RECs generated by its resources. PSE's accounting for the revenues created by the sale of RECs was determined in PSE's

Docket UE-070725.

Q. Do PSE's RECs transactions impact power costs?

A. No, PSE's bundled REC sales do not affect total power costs. Under these agreements, PSE delivers firm physical market-sourced power at the Mid-Columbia ("Mid-C") hub in quantities equivalent to the Renewable Portfolio Standard-eligible product quantities defined in the contracts. The buyers are obligated to pay the contractual on- or off-peak Mid-C index price as published by the Intercontinental Exchange, Inc. ("ICE") for the power delivered plus a fixed price per MWh for the RECs. PSE then purchases the equivalent physical power obligation to settle at the contractual daily Mid-C index price as published by the ICE. Any difference between the cost of the purchased power and the proceeds from the sale of the power is removed from power costs and deferred in FERC Account 254. As a result, the cost of the physical power sold equals the cost of the power purchased, resulting in a zero impact to power costs.

IV. PCA PERIOD 9 POWER COSTS

A. PCA Period 9 Power Resources

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

A. There were a number of changes to PSE's portfolio that were reflected in the PCA

Period 9 power costs that were not recovered in rates for the entire PCA Period 9. Specifically, the PCA Period 9 power costs included:

(1) Energy from the following newly acquired resources which were included in the baseline rate effective April 8, 2010 as they were deemed prudent in PSE's 2009 GRC:

a. The Mint Farm Energy Center ("Mint Farm") gas-fired combined cycle combustion turbine provided 296 MW of additional capacity. Costs for this resource were not subject to an adjustment under Exhibit G as is discussed in more detail below.

b. The Wild Horse Wind Project expansion ("Wild Horse Expansion") added 44 MW of nameplate capacity. Costs for this resource were not subject to an adjustment under Exhibit G as is discussed in more detail below.

c. The Credit Suisse Purchased Power Agreement ("PPA") was signed to replace, effective January 1, 2009, the terminated 50 MW PPA with Lehman Brothers ("Lehman PPA") upon Lehman's announcement to file Chapter 11 bankruptcy.

d. A PPA with Qualco Dairy Digester (0.50 MW of nameplate capacity) effective March 9, 2009.

(2) Extension of the contracts between PSE and

a. Occidental Energy Marketing, Inc. for gas transportation between the Rockies region and Sumas through June 30, 2011; and

b. Puget Sound Hydro, LLC for the Nooksack hydro agreement (2.5 MW).

(3) Contracts executed or extended under PSE's Schedule 91 tariff. Schedule 91 contracts are discussed in the testimony of Mr. John Story, Exhibit No.___(JHS-1T). For PCA Period 9, these included:

a. a PPA with Port Townsend Paper Corporation for the output of a 0.375 MW hydro generator; and

b. a PPA with Farm Power Rexville, LLC effective August 28, 2009 for the output of an anaerobic manure digester (0.75 MW of additional capacity).

(4) A five year PPA with [redacted] Corporation to serve the retail load in

Point Roberts, Washington that extends the existing contract effective October 1, 2009 at a lower cost per MWh. This contract was deemed prudent in PSE's 2009 GRC.

(5) The expiration of Northwestern Energy Contract on December 28, 2010.

(6) Lower generation and costs under the Public Utility District No. 2 of Grant County, Washington ("Grant County PUD") Mid-C contract terms effective November 1, 2009. This contract was approved in PSE's 2006 general rate case, Docket Nos. UE-060266 and UG-060267 (consolidated) and are, therefore, not subject to adjustment under Exhibit G. Specifically, the PCA Period 9 hydro generation was reduced to reflect:

a. PSE's updated Grant County PUD contract ownership share for 2010. PSE's Wanapum Development and Priest Rapids Development Hydroelectric Projects ownership share changed from 10.8 percent and 0.54 percent, respectively, to 1.22 percent of the combined Priest Rapids Hydroelectric Project projection on January 1, 2010. This reduced PSE's 117.3 MW capacity share of the Priest Rapids Hydroelectric Project to 24.3 MW at January 1, 2010.

b. PSE's decision not to purchase any Meaningful Priority under the Grant County PUD contract which allows purchasers to buy a percentage of the Reasonable Portion generation (referred to as "Meaningful Priority") at a price determined by Grant County PUD's annual power auction. PSE declined the option for the 2010 calendar year after anticipating an above market auction price due to increasing participation by power marketers willing to pay a premium for Mid-C power. The actual 2010 auction price using actual generation was approximately $54.23 per MWh.

Q. Please provide more information regarding Mint Farm and the Wild Horse Expansion resources.

A. Mint Farm was purchased and placed in-service in December 2008. PSE then took Mint Farm offline for capital and maintenance improvements to bring the plant to company operating and insurance standards and brought the unit back online on

January 19, 2009. The Wild Horse Expansion's additional 22 wind turbines entered commercial operation on November 9, 2009. PSE deferred costs associated with these new resources through April 7, 2010, pursuant to RCW 80.80.060, until the costs associated with these resources were included in rates effective April 8, 2010 as allowed by the final order in PSE's 2009 GRC. The exclusion of the deferred costs for these resources from analysis in Exhibit G for PCA Period 9 is discussed in the Prefiled Direct Testimony of Mr. John Story, Exhibit No. ___(JHS-1T).

Q. Were any of the above new resources subject to the PCA bridge mechanism Exhibit G during PCA Period 9?

A. Yes. The PCA bridge mechanism is PCA Exhibit G, "New Resource Adjustment". Power costs during PCA Period 9 for new resources with terms greater than two years that are not yet recovered in rates, except those noted above, were analyzed for adjustment under PCA Exhibit G. The new resources that were adjusted under Exhibit G until they were included in rates on April 8, 2010, include the PPAs with Qualco Dairy Digester and Credit Suisse. Please see Mr. Story's Prefiled Direct Testimony, Exhibit No. ___(JHS-1T), for a more detailed discussion of the PCA Period 9 Exhibit G calculation.

Q. Did PSE acquire any new resources during PCA Period 9 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 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 decisions whether to dispatch gas-fired generation or to buy or sell power versus 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 improve the reliability of 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 value 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 hedging 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 9 by describing actual hedging strategy decisions and their execution undertaken by PSE with respect to its power supply for a sample month, May 2010. *See* Exhibit No. ___(DEM-3C).

B. PSE's Management of its Power Portfolio and Related Fuel Supply for PCA Period 9

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

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

PSE's Energy Management Committee ("EMC") – composed of senior PSE officers – oversees the activities performed by the EPM 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 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 were 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] became the Programmatically Managed Hedge in accordance with the EMC approved strategy. EPM department staff utilize the Programmatically Managed Hedge 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. ___(DEM-3C), which also steps through a sample month, May 2010. Such exposure reduction is subject to minimum and maximum monthly limits to reduce timing and market risks associated with hedging activities.

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

REDACTED VERSION

Hedging Purview Impacting PCA 9	Total Months Managed	Programmatically Managed Hedge	Actively Managed Hedge
Pre-October 2007	[redacted]	[redacted]	Balance of the Current Month + Next Full [redacted]
Post-October 2007	[redacted]	[redacted]	Balance of the Current Month + Next Full [redacted]

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

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", changes 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 economic 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. ___(DEM-6C).

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

A. With PSE's aggregated energy position and net exposure defined for a particular period, the EPM department evaluates and develops risk management strategy proposals and/or executes transactions around the purchase or sale of gas or power, as appropriate, to balance the position and reduce the exposure of the open position. Execution entails entering into specific transactions with approved counterparties, using 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 limits set forth in the plan outlining 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 [redacted] in the Programmatically Managed Hedge period.

REDACTED VERSION

Q. Do the Energy Portfolio Management 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 limits of the plan. EPM department staff must then make use of market fundamentals, water supply and weather forecasts that impact the wholesale electric and gas markets to decide whether to press toward the maximum or minimum monthly limits, or somewhere in between. EPM department staff also determines when and how to execute such transactions to maintain each month's net exposure reduction within the maximum and minimum limits.

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

A. The EPM department utilizes a wide set of tools and sources of information to help its members make informed decisions about dispatching plants, purchasing fuel and executing hedges approved by the EMC. They also hold several meetings each month so that the teams can review operational events, discuss market trends and fundamentals 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 EPM department staff with years of experience in energy trading, optimization and risk management.

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

A. The EPM department 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, PSE staff review forecasted wholesale market prices and supply/demand fundamentals, as well as commodity price technical analysis, such as trading firm publications and consulting service forecasts.

EPM department staff also receive real-time information from a variety of sources such as: Future Source; Intercontinental Exchange (live price data); live broker lines, where current transactions are communicated though a speaker system; and other tools. The EPM department 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 EPM department also uses 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 also uses a counterparty credit risk management system to assist the Credit Risk Management group and the EPM department staff in evaluating credit issues associated with potential transactions. With this tool, staff can review data that is gathered and calculated daily, including:

- Moody's and S&P rating of the entity;
- applicable information about the parent of the entity;
- amount of parent guarantee credit provided to PSE, if applicable;
- the entity's amounts payable and receivable;
- the aggregate mark to market exposure of all open forward transactions with the entity (the dollar value of the difference between the original contract price and current market price);
- the credit limit assigned to the entity;
- the existence of netting terms; and
- Accounting Standards Codification 815 (formerly Financial Accounting Standards Board Statement No. 133) designations. This Statement provides accounting and reporting for derivative instruments and hedging activities.

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. The preceding 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 May 2004, during PCA Period 2, PSE began to employ a metric called Margin at Risk ("MaR"), which measures risk reduction as a result of incremental hedging. *See* Exhibit No. ___(DEM-4C). PSE has incorporated the MaR concept into the evaluation process for hedge strategies to measure risk reduction for various alternatives. A series of hedge strategies (transaction types) are run through the portfolio, providing a table of how much risk reduction is gained by month and by strategy. The MaR concept assists with deciding how to allocate dollars in a credit-constrained environment, thus providing an additional tool for choosing between available commodities. *See* Exhibit No. ___(DEM-7C).

In July 2004, the EMC approved a continuation of a dollar cost averaging strategy (hedging on a regular schedule over a lengthy period, in order to capture lower as well as higher prices during periods of volatility) informed by MaR. However, the EMC directed that PSE 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 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.

EPM 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. As mentioned above, in October 2007, PSE extended staff's transactional purview from [redacted] to [redacted]. At that time, the first [redacted] became the Actively Managed Hedge in accordance with the Procedures Manual and the remaining [redacted] became the "Programmatically Managed Hedge" in accordance with the EMC approved strategy. The revised strategy retained many of the same features as the previous hedging strategy. These include

(i) a required ratable reduction of monthly commodity exposure removed each month;

(ii) the volume of monthly hedging and intra-month timing for hedging is informed by market fundamentals; and

(iii) hedging targets are established on the basis of the minimum or maximum amount of commodity exposure allowed under the EMC approved strategy.

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

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.

REDACTED VERSION

2. Application of PSE's Risk Management System to PCA Period 9 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 9 power supply and costs?

A. Yes. Take, for example, PSE's energy requirements for May 2010. Beginning in [redacted], PSE's EPM staff began to actively reduce spot market price exposure for the delivery period May 2010. From [redacted] through [redacted], on a monthly or bi-monthly basis, EPM department staff developed strategies to reduce PSE's exposure with respect to its electric supply needs for May 2010. Such strategies reflected updated Position and Exposure Reports generated by PSE's risk system, market heat rates, hydro conditions and weather fundamentals, and other available information. In accordance with the EMC approved Programmatic Hedging Plan and within the limits described therein, PSE staff executed these strategies by entering into hedging transactions. EPM Department staff can make recommendations to depart from this plan, but execution of such hedges is subject to EMC approval. With respect to the May 2010 power supply, EPM department staff did not make any such recommendations, but instead kept the EMC informed of its analyses and activities. See Exhibit No. ___(DEM-3C) for discussion of the hedges transacted for May 2010, which are presented in Exhibit Nos. ___(DEM-9C) and ___(DEM-10C).

Beginning in [redacted], the power supply for May 2010 rolled into staff's newly extended [redacted] Programmatically Managed Hedge purview. Beginning in [redacted], the power supply for May 2010 rolled into staff's Actively Managed Hedge - at which point staff continued to analyze PSE's position for May 2010 on a daily basis and, based on market conditions and other information available to them at the time, took actions 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. ___(DEM-3C).

Q. Are the activities described in Exhibit No. ___(DEM-3C) the only risk management activities that PSE undertook for PCA Period 9?

A. No. Similar activities were undertaken with respect to managing PSE's portfolio and exposure for the entire PCA Period 9. Some of that information is apparent from the materials presented in Exhibit No. ___(DEM-3C) and the other exhibits filed with my Prefiled Direct Testimony. However, describing and documenting all of the details of such activities for the entire PCA Period 9 would be a monumental task and are considered to be outside the scope of this testimony.

Q. How did PSE manage gas supply for Tenaska during PCA Period 9?

A. PSE managed gas supply for Tenaska as part of its overall power portfolio by applying the risk management tools and systems described above. PSE ultimately hedged the financial exposure associated with its power portfolio taking into account the probabilistic dispatch rate of Tenaska and other plants. This means that PSE hedged fuel supply in the financial gas derivatives market over time as necessary to reduce open position exposure and ultimately balance the position on a probabilistic basis. The physical fuel requirement was then acquired in the monthly or daily spot market, whichever was determined to be most advantageous at the time.

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

Q. Why does PSE enter into winter peaking contracts?

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

Q. How did PSE approach the decisions whether and how to enter into winter peaking contracts for the winter months of calendar 2010?

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

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

C. <u>PSE's PCA Period 9 Actual Power Costs</u>

Q. Were there any accounting adjustments made in PCA Period 9?

A. Yes, there were four adjustments made to the PCA Period 9 power costs which lowered the 2010 power costs by $10.8 million. These adjustments are noted below and are also discussed in greater detail in Mr. John Story's Exhibit No. ___(JHS-1T):

1. A $5.6 million credit was posted to PCA Period 9 power costs for a financial settlement reached with Bonneville Power Administration ("BPA") to reimburse PSE for a net over-return of losses under its contracts with BPA from July 2001 through August 2009. As this settlement related to PCA Periods 1 through 8, the credit was removed from the PCA Period 9 power costs and was allocated to the appropriate PCA periods, as required under the PCA Mechanism true-up methodology.

2. During 2009, PSE received a $1.6 million payment as a result of PSE and the other Colstrip 3&4 unit owners entering into a settlement agreement with Western Energy Company ("WECo") regarding reclamation costs included in the 2007 coal commodity costs. These costs were over $1 million, so were removed from the PCA 9 power costs and the power costs for PCA Period 6 power costs were restated as required under the PCA Mechanism true-up methodology.

3. PSE and the other Colstrip 3&4 unit owners entered into a settlement agreement with WECo to pay $0.3 million in royalties pertaining to the years 1996 through 2001. As this time frame is prior to the July 1, 2002 start of the PCA Mechanism, these costs were removed from the PCA Period 9 power costs.

4. In June 2010, PSE lowered the carrying value of its receivable from the California Independent System Operators by $17.8 million. As this receivable related to activity prior to the start of the PCA Mechanism, this expense was removed from the PCA Period 9 power costs as required under the PCA Mechanism true-up methodology.

Q. How did PSE's actual power costs during PCA Period 9 compare to the power costs recovered in rates?

A. PSE's actual power costs were $38.3 million above the amounts recovered through the Power Cost Baseline Rate during the calendar year 2010 PCA Period 9. During this time, PSE was adversely impacted by warmer and drier than normal weather which caused: (1) lower Mid-Columbia ("Mid-C") hydro generation (due to 76 percent of normal runoff at Grand Coulee during the January - July 2010 period where normal is considered to be the 30 year average from 1971 to 2000,see Exhibit No. ___(DEM-12)); (2) lower than expected load; and (3) lower than expected wind generation. In the first quarter ("Q1") of 2010 alone, PSE under recovered $36.3 million of power costs per the PCA calculation. Although power costs are expected to be under recovered in the first quarter, the magnitude of this under recovery was well above expected levels of those seen in the past. In addition, the continued under recoveries caused by the below normal hydro conditions throughout the remainder of 2010 made it impossible for PSE to recover from the set-back that occurred in Q1 2010. The table below shows the dramatic decrease in wind and hydro generation as well as load compared to what was in rates during Q1 2010.

Q1 2010 actual generation and load compared to rates

(in MWhs)	Q1 2010	Q1 in Rates [1]	Increase / (Decrease)	% Change
Mid-C Hydro (net of CEA)	853,306	1,411,476	(558,170)	-40%
Westside Hydro	225,965	267,692	(41,727)	-16%
Wind (PSE-owned & Klondike)	184,659	331,588	(146,929)	-44%
Load (GPI)	6,072,722	6,649,905	(577,184)	-9%

[1] The Q1 in rates amounts represent the Jan-Mar generation and load embedded in the 2007 GRC.

Although weather was certainly the biggest driver of the PCA imbalance during PCA Period 9, PSE was able to offset some of the under recovery through lower costs. First, coal costs were lower due to less than budgeted Western Energy Company fixed and variable costs. Furthermore, higher market heat rates resulted in an increase in the output from PSE's gas fired units. Finally, Mid-C contract costs were lower than the costs embedded in rates primarily due to higher Priest Rapids auction revenues than were included in the 2007 GRC, which were in rates during the PCA Period 9 through April 7, 2010 (the 2009 GRC rates were effective April 8, 2010). Lower spending at some of the public utility districts also reduced PSE's Mid-C contract costs.

V. CONCLUSION

Q. Do you believe that PSE has met the Commission's prudence standard with respect to its power costs during PCA Period 9?

A. Yes; PSE met the Commission's prudence standard for the PCA Period 9 power costs because PSE's management of its power costs during PCA Period 9 was reasonable. PSE has structures and processes in place to formulate strategies for controlling 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.