EXHIBIT NO. ___(DEM-1CT)
DOCKET NO. UE-11___/UG-11___
2011 PSE GENERAL RATE CASE
WITNESS: DAVID E. MILLS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-11____** **Docket No. UG-11____**

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

REDACTED
VERSION

JUNE 13, 2011

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF DAVID E. MILLS

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

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

A. My name is David E. Mills. My business address is 10885 NE Fourth Street, P.O. Box 97034, Bellevue, WA 98009-9734. I am the Director, Energy Supply & 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. Please explain your duties as Director, Energy Supply & Planning for PSE.

A. My responsibilities include oversight of PSE's Power Supply Operations, Gas Supply Operations, Renewable Resource Integration and Merchant Transmission 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. I was responsible for the oversight of the development of the 2009 Integrated Resource Plan (the "2009 IRP") and the 2009 Integrated Resource Plan Addendum (the "2009 IRP Addendum"). Please see Exhibit No. ___(RG-3) and Exhibit No. ___(RG-4) for copies of the 2009 IRP and the 2009 IRP Addendum, respectively.

Q. What is the key take away from your prefiled direct testimony in this proceeding?

A. Although this testimony covers many power cost-related topics in painstaking detail, the highlight of my testimony is that power costs (net of production O&M) are lower by approximately $88.2 million relative to power costs recovered in current rates. There are a number of reasons for this large decline, which are discussed in greater detail below, but a key driver is a drop in natural gas prices which are down an average of $1.25 per MMBtu as compared to current rates. With power costs projected to be $992.5 million in the rate year, a reduction of $88.2 million is a significant amount that will help reduce the impact of other cost pressures.

Q. Please summarize the scope of your prefiled direct testimony in this proceeding.

A. This prefiled direct testimony addresses the following issues relevant to the power costs for this proceeding's rate year May 2012 through April 2013 (the "rate year"):

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

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

(iii) PSE's rate year transmission considerations;

(iv) PSE's experience, analytics and forecast of wind generation and renewable resource integration costs;

(v) PSE's agreements regarding renewable energy;

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

(vii) PSE's rate year production operations and maintenance expense adjustments and projections;

(viii) a comparison of PSE's projected rate year power costs for this proceeding to PSE's projected rate year power costs approved in PSE's last general rate case in Docket Nos. UE-090704 and UG-090705 (consolidated) (the "2009 GRC"); and

(ix) a comparison of PSE's actual power costs to those projected in rates.

II. VOLATILITY AND RISK IN PSE'S ELECTRIC AND NATURAL GAS RESOURCE PORTFOLIOS

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

A. PSE's resource portfolio is subject to significant volatility and risk that ultimately

[1] These "portfolios" consist of resources available to PSE to serve its customers. The electric portfolio includes generation facilities, purchased power and transmission capacity. The gas portfolio includes gas supply, storage and pipeline transportation, and gas transportation capacities. Please see Exhibit No. ___(RG-3) for a discussion of PSE's power and gas portfolios.

have a substantial impact on energy costs.

Q. What drives volatility and risk in the natural gas portfolio?

A. PSE's natural gas supply portfolio contains a diverse mix of supply contracts from various producing areas, including the Western Canadian Sedimentary Basin, the Rocky Mountain area, and the San Juan Basin.

The major causes of gas cost volatility for PSE are: (i) demand variations due to changes in weather; (ii) gas transportation constraints; and (iii) wholesale natural gas market prices. PSE's retail natural gas demand is closely correlated to temperature (e.g., demand increases as temperatures decrease). PSE addresses this gas cost volatility through gas storage and transactions in the wholesale gas markets. Because PSE purchases and sells in the wholesale gas markets to manage this variability, PSE faces risks associated with the volatility of market prices for gas at the various supply points.

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

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

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

(ii) weather uncertainty affecting power usage;

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

(iv) risk of forced generation outages;

(v) variability of wind generation; and

(vi) transmission and transportation constraints.

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

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

A. There are four main factors that can affect streamflow:

(i) below average runoffs;

(ii) average runoffs;

(iii) above average runoffs; and

(iv) the timing or shape of the runoff.

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

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

A. The Pacific Northwest is a winter peaking region in that the winter peak demand is higher than the summer peak. The level of PSE's electric retail load is correlated with temperature (i.e., PSE's load increases as temperatures decline during the winter heating season). In light of the significant electric heating load in PSE's service territory, PSE's costs related to load/temperature uncertainty can be significant. Although still a winter peaking utility, PSE also experiences summer peaking demand. This is due in part to increasing use of electric air conditioning and presents another example of electric load volatility attributable to temperature.

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

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

Q. Please describe the volatility related to forced outages.

A. As shown in the table below, for the rate year, PSE will rely on 2,344 megawatts ("MW") of thermal generating units to help meet its customer loads. The capacities shown represent the operational capacities at International Standard Organization conditions. These units include:

(i) 657 MW of large, base-load coal generation with low variable fuel costs;

(ii) 1,081 MW of gas-fired, combined-cycle combustion turbine co-generation with moderate heat rate conversions; and

(iii) 606 MW of relatively less-efficient, simple-cycle gas and oil-fired combustion turbine generation.

Table 1 below presents PSE's thermal generation units.

Table 1. PSE's Thermal Generation Units

	Capacity (MW)
Coal	657
Goldendale	267
Mint Farm	288
Frederickson 1/Capital Power	134
Encogen	166
Sumas	127
NUGs	100
Simple Cycle CTs	606
Total MWs	**2,344**

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

Q. Please explain the variability of wind generation.

A. PSE's power portfolio benefits from approximately 822 MW of wind generation. Wind resources, however, have significant variability as evidenced by comparing short-term wind generation forecasts to actual generation. PSE must manage this short-term generation variability by reshaping its contracted Mid-Columbia ("Mid-C") hydro generation and utilizing other generating assets within its system to accommodate the wind projects' power variations. Such reshaping takes place on a real-time basis and affects PSE's power costs as PSE's other resources' generation levels are adjusted on a real-time basis to accommodate fluctuations in wind generation. Wind integration costs are discussed in more detail below.

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

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

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

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

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

A. Yes. Examples of other risks to PSE's power and gas costs include, but are not limited to, the following:

- counterparty credit risk, which is the risk of default by PSE's counterparties on contractual obligations; and
- execution risk, which refers to the ability to execute wholesale market transactions. Market liquidity, counterparty credit requirements, PSE's credit standing, and contractual requirements are examples of execution risk.

III. PSE'S MANAGEMENT OF POWER AND GAS COST RISKS

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

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

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

A. PSE uses the following measures to manage its electric portfolio within a dynamic and complex environment:

- internal organizations and staff dedicated to managing portfolio risks;
- executive and Board of Directors-level oversight of staff's portfolio management activities;
- specific procedures and policies governing energy portfolio management activities;
- production cost modeling techniques that develop a 250-scenario probabilistic view of PSE's wholesale electric portfolio and its underlying risks;
- use of programmatic hedging strategies that specify a range of monthly volumes to be hedged, depending upon market fundamentals and energy portfolio management staff's expertise;
- selection of specific commodities to be hedged as informed by Margin at Risk analyses;
- revision of strategies to incorporate up-to-date fundamental views of energy commodity markets;
- a $350 million unsecured revolving credit agreement to support PSE's energy hedging activities; and
- a counterparty credit risk system.

Q. Has PSE revised its hedging strategies since the 2009 GRC?

A. Although PSE constantly reviews its hedging strategies for improvement, PSE has not revised its hedging strategies since the 2009 GRC. Please see Exhibit No. ___(DEM-3C) for an overview of PSE's current hedging strategies. Please also see Exhibit No. ___(DEM-4C) for an Energy Cost Risk Management presentation made to Commission Staff regarding PSE's hedging strategies.

Q. Please discuss the hedges included in rate year power costs.

A. The rate year power costs include gas for power and power contracts that have been transacted as of the gas price cut off date (April 12, 2011) for the rate year months May 2012 through April 2013.

Table 2 below provides a summary of the rate year hedges included in rate year power costs:

Table 2. PSE's 2011 GRC Rate Year Short-Term Hedges

	Contract	Volume	Rate Year Cost	Average
On-Peak Power (MWhs)	Fixed	2,383,600	$110,635,040	$46.42
Off-Peak Power (MWhs)	Fixed	1,258,975	$43,764,774	$34.76
Total Power (MWhs)	Fixed	3,642,575	$154,399,814	$42.39
Financial Gas for Power (Dth)	Fixed	21,787,500	$119,677,550	$5.49
Physical Gas for Power (Dth)	Index	12,939,410	$57,692,633	$4.46

As discussed below, the gas for power contracts are marked to market in the "Not in Models" calculation and the power contracts are included within the AURORA model.

IV. TRANSMISSION

A. Transmission Reassignments

Q. Please describe transmission reassignments.

A. In order to reliably serve load by reducing exposure to transmission curtailment, PSE purchases long-term firm transmission volumes to secure delivery of energy from generation and market resources to meet peak customer demand. Long-term firm transmission is sold on an annual contract basis based on the maximum amount of need during a year. In doing so, PSE has the transmission available at all times and maintains its long-term transmission rights.

As discussed above, PSE's customer peak loads typically occur in the winter. It is generally due to this shaping of peak load demand—higher in the winter, lower in the summer months—that PSE may have times of surplus Point-to-Point ("PTP") transmission. Under the pro forma Open Access Transmission Tariff ("OATT") of the Federal Energy Regulatory Commission ("FERC"), a transmission customer has the right to sell excess firm PTP transmission capacity rights to eligible customers.

Q. Does PSE have a transmission tariff on file with FERC to sell excess BPA transmission?

A. Yes. BPA does not follow the pro forma OATT, which required PSE to file a separate transmission tariff with FERC to sell excess BPA transmission. Beginning in March 2010, PSE had all of the regulatory approvals and compliance procedures to reassign excess BPA PTP transmission rights. Using intra- and next-day transactions, PSE reassigns transmission on a short-term basis after considering variations in load and generation which are caused by changes in temperatures and market heat rates, respectively. During the first year the transmission tariff was in effect, PSE revenues associated with sales of excess transmission were $1.9 million.

Q. Has PSE included sales of excess transmission in its rate year power costs?

A. Yes. PSE calculated the excess transmission available for resale during the rate year by comparing, on a monthly basis, its firm rate year PTP transmission rights to the forecast PTP volumes required to meet customer load. A review of the monthly transmission calculated to be available for resale to the amounts actually sold indicates that, on average, PSE was able to resell approximately 62 percent of the volumes available for resale for the period March 2010 through February 2011. Accordingly, 62 percent of the excess transmission estimated as available for resale in the rate year is forecast to be sold at the current average resale price. Based upon this calculation, PSE has reduced rate year power costs by $1.3 million for transmission resale revenues.

B. BPA 2012-2013 Rate Case

Q. Is BPA planning to change transmission rates during the rate period in this proceeding?

A. Yes. BPA is currently conducting a combined power and transmission rate proceeding to set new rates for BPA fiscal year 2012-2013 ("BPA 2012 Rate Cases") effective October 1, 2011. In January 2011, BPA offered customers a partial settlement that includes a zero percent increase for the FY 2012–2013 period, for all transmission services and for two ancillary services: (i) Scheduling, System Control and Dispatch Service; and (ii) Reactive Supply and Voltage Control from Generation Sources Service. The remaining ancillary services and all control area services are not covered by the partial settlement.

BPA proposes to increase the following rates of interest to PSE:

(i) an increase in the Operating Reserve rates for Spinning Reserve Service from $8.53 to $10.20 per MWh;

(ii) an increase in the Supplemental Reserve Service from $8.24 to $9.63 per MWh; and

(iii) an increase in the Variable Energy Resource Balancing Services ("VERBS") rate from $1.29 to $1.32 per kilowatt month.

PSE has included increases for these transmission services in the pro forma transmission costs included in the rate year power cost forecast. Please see below for a discussion of the VERBS (wind integration) costs in more detail. PSE proposes to update these transmission rates during this proceeding to reflect BPA's final Record of Decision, which BPA has planned to issue on July 25, 2011.

Q. Are there any other changes to the transmission rates in the rate year?

A. Yes. BPA provided notice to the Colstrip owners (Avista Corporation, NorthWestern Energy, PacifiCorp, Portland General Electric Company, and PSE) that BPA Transmission Services ("BPAT") is terminating the Capacity Exchange provision contained in the Montana Intertie Agreement on October 1, 2011. PSE pays BPA each month for PSE's use of BPA's Townsend-Garrison Transmission. This amount is net of the credit that BPA pays the Colstrip owners for use of the Broadview-Townsend line. On October 1, 2011, PSE's monthly charge will increase from $316,472 to $406,844, an increase of $90,372 per month or $1,084,464 per year.

C. <u>Transmission Capacity</u>

Q. Please discuss the changes to PSE's transmission capacities for the rate year.

A. PSE relies on existing firm BPA transmission contracts from Mid-C to PSE's system to meet its capacity need. PSE uses this transmission to wheel both long- and short-term contract resources to PSE's system to serve load. PSE has elected to renew for a five-year term the contract with BPA for 23 MW of firm transmission that expired earlier this year which was related to the Municipal Steam Waste contract with the City of Spokane, which expires December 31, 2011. By renewing this transmission contract at a rate year cost of $414,000, PSE has increased its ability to purchase short-term resources at the Mid-C trading hub and reduced its transmission capacity need by 23 MW starting in 2012.

V. WIND RESOURCES

A. <u>Wind Generation</u>

Q. Please describe PSE's wind resources.

A. PSE's nearly 822 MW of wind capacity is comprised of owned and contracted wind resources. PSE currently owns several wind projects:

(i) the Hopkins Ridge Wind Project ("<u>Hopkins Ridge</u>"), located in southeast Washington near the town of Dayton, began commercial operation in November 2005 and includes 87 Vestas V80 wind turbines with an electrical capacity of 156.6 MW;[4]

(ii) the Wild Horse Wind Project ("Wild Horse"), located in central Washington near Ellensburg, with 127 Vestas V80 turbines and an electrical capacity of 228.6 MW;[5] and

(iii) the Wild Horse Expansion Wind Project ("Wild Horse Expansion") located in central Washington with 22 Vestas V80 turbines and an electrical capacity of 44 MW.[6]

As discussed in the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT), PSE is currently in the process of constructing Phase 1 of the Lower Snake River Wind Project ("LSR Phase 1"), near Hopkins Ridge. LSR Phase 1 is scheduled to come online April 2012 and will have 149 turbines with an electrical capacity of 342.7 MW.

Additionally, PSE has a long-term power purchase agreement ("PPA") with Klondike Wind Power III, LLC, an affiliate of Iberdrola Renewables, Inc. ("Iberdrola Renewables"), for 22.36 percent of the output of the Klondike III Wind Project ("Klondike III") located in the Lower Columbia River Gorge region.

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[4] The 156.6 MW capacity includes the Hopkins Ridge Infill 7.2 MW capacity from the additional four turbines that went into service August 2008. The original 83 Hopkins Ridge turbines were placed in service November 27, 2005.

[5] Wild Horse was placed in service December 22, 2006.

[6] The Wild Horse Expansion project was placed in service November 9, 2009.

Table 3 below provides a summary of PSE's expected rate year wind generation capacity:

Table 3. PSE's Wind Generation Capacity

	Capacity (MW)	# Turbines
Hopkins Ridge	156.6	87
Wild Horse	228.6	127
Wild Horse Expansion	44.0	22
LSR Phase 1	342.7	149
Klondike III PPA	50.0	N/A
Total	**821.9**	**385**

Q. How have PSE's wind facilities performed since beginning commercial operation?

A. PSE's owned wind facilities have a very good safety record and have posted high availability statistics. Since their respective in-service dates through December 31, 2010, PSE's wind facilities have generated nearly 4.5 million MWhs. As detailed in Table 4 below, PSE's wind facilities' capacity factors have averaged less than the pre-construction estimates.

Table 4. Capacity Factors

	Hopkins Ridge	Wild Horse	Wild Horse Expansion
Pre-Construction Estimate	[redacted]%	[redacted]%	[redacted]%
In-Service through 12/31/10	[redacted]%	[redacted]%	[redacted]%
11GRC Test Year 2010	[redacted]%	[redacted]%	[redacted]%
2010 Updated Estimate	[redacted]%	[redacted]%	N/A

Capacity factor is the ratio of the actual energy produced over a specified period of time divided by the energy produced if the facility had operated at full nameplate capacity for the same period.

Q. Please compare the actual capacity factors for PSE's wind facilities to their pre-construction capacity factors.

A. Wind capacity factors were estimated as part of the original acquisition and development process for Hopkins Ridge and Wild Horse.[7] These estimated capacity factors were provided by a leading wind consultant, Garrad-Hassan, after an analysis of the wind resource for each project site. Since the start of commercial operations, both Hopkins Ridge and Wild Horse have posted an average actual capacity factor below Garrad-Hassan's original capacity factor estimates. It should be noted that these actual capacity factors have *not* been adjusted for external or abnormal condition impacts (such as transmission curtailments, serial defect repairs, and force majeure events). Taking into consideration the cumulative effect of these impacts would increase the actual capacity factors.

Q. Has PSE performed an analysis of the difference between the actual and pre-construction capacity factors for Hopkins Ridge and Wild Horse?

A. Yes. In 2010, PSE hired DNV Global Energy Concepts, Inc. ("DNV-GEC") to review the net energy production estimate for the Wild Horse and Hopkins Ridge

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[7] For purposes of this discussion, the Wild Horse Expansion project is not included as it is more recently constructed, so its analytics include current wind forecast methodologies. The four turbines added to the original Hopkins Ridge wind facility are included in the Hopkins Ridge statistics.

projects based on:

(i) wind resource information provided in pre-construction energy assessments; and

(ii) previous analysis conducted for PSE related to these or nearby projects.

Q. What were the results of this evaluation?

A. DNV-GEC's analysis indicates that the capacity factor and annual energy estimates at both Hopkins Ridge and Wild Horse would have been reduced if the evaluation methodology used today had been applied to the original analyses. Based on the latest methodology, the estimated capacity factors for Hopkins Ridge and Wild Horse would be reduced to [redacted] percent and [redacted] percent, respectively.

Q. How has the evaluation methodology changed?

A. Industry wide, capacity factor is strongly influenced by the production availability of the turbines, the reliability of the wind resource itself, and externalities, such as transmission availability. In 2006, Global Energy Concepts ("GEC") performed a study comparing pre-construction energy estimates for 24 wind power facilities across North America having a combined 99 facility-years of operation to actual first year production. The results clearly show reduced actual production relative to expectations due to:

1) over-estimation of gross energy production due to wind speed estimating bias; and

2) energy estimate process bias (losses higher than estimated).

Examination of the causes shows that many effects, both meteorological and mechanical, were not quantitatively evaluated in the uncertainty analysis performed as part of pre-construction energy analysis. For example, turbine availability or power performance may have been assumed to be fixed at relatively high levels, while actual operating experience indicates that these levels decline somewhat over the operating life of the facility. In some cases, entire categories of losses were not considered or were underestimated. For example, at some projects, weather losses were evaluated based on expected icing downtime, while actual operations have shown that more energy is lost through other weather-related problems such as lightning, hail, weather-related faults, and reduced site access. As the differences between pre-construction energy estimates and actual production performance have gradually been recognized, developers and consultants alike have refined their wind resource analyses.

Q. What are the wind resource capacity factors included in the rate year power costs?

A. PSE's prior rate cases have included the original capacity factors based upon the Garrad-Hassan pre-construction estimates for Hopkins Ridge and Wild Horse. For this rate proceeding, however, PSE used DNV-GEC's updated capacity factors for both Hopkins Ridge and Wild Horse as inputs to the AURORA model: [redacted] percent and [redacted] percent, respectively. DNV-GEC's lower capacity factors for Hopkins Ridge and Wild Horse reduced the wind generation included in the

AURORA model by 29,532 and 35,327 MWhs, respectively, for a total reduction of 64,859 MWhs. The AURORA model replaces the lost wind generation with market purchases, resulting in an increase to power costs which are mitigated by lower wind integration costs calculated in the "Not in Models" calculation discussed below. As a result, the rate year power costs increased approximately $2.0 million.

B. <u>Wind Integration Costs</u>

1. <u>Wind Integration Overview</u>

Q. What are wind integration costs?

A. Generally, wind integration costs incurred by PSE, internally and through BPA, are equal to the opportunity costs of having to reserve capacity to balance wind generation. In essence, generation capacity that may have been dispatched but for the presence of wind is withheld from the energy market. Conversely, generation that would not have been dispatched, but for the presence of wind, may be committed into the market. Rate year power costs include the cost of integrating PSE's wind resources and include wind integration costs paid to BPA, as well as internal wind integration costs.

Q. Does the integration of wind present any unique challenges for PSE?

A. Yes. Wind generation is an intermittent and non-dispatchable generation resource. Although the variability can be managed in a manner similar to managing PSE's load, the unpredictable nature of wind creates additional system uncertainty. Consequently, there can be large differences between the wind generation forecast and actual generation. These large, short-term, unanticipated changes (up or down) in generation present some of the greatest challenges that PSE operators have to effectively manage to ensure compliance with its electric system reliability standards. If actual real-time generation output diverges from the hourly scheduled wind output, the operator must rebalance the system by increasing or decreasing generation from the Mid-C and/or other generating assets within PSE's system. To ensure that PSE has sufficient ability to increase (up following) or decrease (down following) generation to balance wind, generation capacity must be held in reserve.

Q. What Balancing Authorities are responsible for integrating PSE wind?

A. The Hopkins Ridge and Klondike III wind projects are located in the BPA Balancing Authority Area ("<u>BA</u>"). As a result, BPA provides integration services to manage the variable output of these wind projects. Under this service, BPA delivers the hourly scheduled amount of wind generation to PSE's system by utilizing its own balancing reserves and charges PSE a Generation Imbalance cost. LSR Phase 1 is proposed to be located in BPA's BA.

Wild Horse is located in PSE's BA and is, therefore, PSE's wind integration responsibility. PSE manages the moment-to-moment variability in Wild Horse generation as well as the deviations between actual and scheduled generation.

2. BPA Wind Integration Costs

Q. How are PSE's wind plants integrated in BPA's Balancing Authority?

A. For the Klondike III PPA, PSE receives the forecasted wind output from the project's owner/operator, Iberdrola Renewables. The forecasted wind output is then scheduled with BPA, and PSE receives the hourly scheduled generation.

For Hopkins Ridge, PSE is responsible for providing BPA with the hour-ahead wind generation schedules and receives the hourly scheduled generation from BPA. The instantaneous wind variability and unanticipated wind ramps are managed by BPA's BA. LSR Phase 1 will follow the same structure as Hopkins Ridge.

BPA's integration services are twofold:

(i) Generation Imbalance service, which captures the after-the-fact difference between the hourly average generation produced and the hourly scheduled generation. Generation imbalance is designed to provide an energy accounting mechanism capable of recovering the cost of delivering scheduled versus actual energy; and

(ii) Wind Integration service, known as VERBS, which manages both the "regulation" (the second-to-second, minute-to-minute variability in wind generation) and the wind "generation following" that corrects for differences over a longer time period of 10 to 50 minutes.

BPA's wind integration charges are designed to capture the cost of reserving generating capacity capable of providing generation imbalance service.

Q. What are the estimated rate year wind integration costs incurred by PSE for wind resources in the BPA BA?

A. As noted above, BPA is currently conducting a combined power and transmission rate proceeding to set new rates for their fiscal year 2012-2013. Effective October 1, 2011, BPA's VERBS rate is expected to increase from $1.29 to $1.32 per kilowatt ("kW") per month, causing only a minor increase to power costs for both Hopkins Ridge and Klondike III. (LSR Phase 1 will be subject to the $1.32 rate at its in-service date).

Table 5 below provides the forecast rate year wind integration costs to be paid to BPA for Klondike III PPA, Hopkins Ridge, and LSR Phase 1.

Table 5. 2011 GRC BPA Wind Integration Costs

Wind Project & Capacity	VERBS	Generation Imbalance	Total
Hopkins Ridge (156.6 MW)	[redacted]	[redacted]	[redacted]
Klondike III PPA (50.0 MW)	[redacted]	[redacted]	[redacted]
LSR Phase 1 (342.7 MW)	[redacted]	[redacted]	[redacted]
BPA Wind Integration Costs	**$8,316,000**	**$1,183,914**	**$9,499,914**

As negotiated in the Klondike III PPA, PSE is [redacted].

3. PSE Wind Integration Costs

Q. How does PSE integrate wind within its BA?

A. Wild Horse[8] is in the PSE BA. For most of the rate year, PSE's average annual 726 MW share of Mid-C hydro generation may be sufficient to manage the instantaneous load and Wild Horse wind generation variability and any deviations from their respective schedules.

If actual real-time generation output diverges from the hourly scheduled wind output, the operator must rebalance the system by increasing or decreasing generation from Mid-C and other generating assets within PSE's system. Moment–to–moment changes in wind and load (net load) are generally mitigated by Mid-C hydro generation, which is on Automatic Generation Control ("AGC") and can respond to small fluctuations instantaneously. Large, unanticipated ramping events must be managed within the hour with a combination of AGC and dispatcher actions. Net load following corrects for differences over longer time increments of 10 to 50 minutes between hourly scheduling adjustments.

During the spring runoff period, April through June, when the Columbia River flows are high, the Mid-C hydro system is less flexible because it has to be managed to stay within Total Dissolved Gas ("TDG") limits by minimizing spill. Mid-C flexibility is limited between available capacity and the minimum

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[8] The Wild Horse wind farm includes both Wild Horse and the Wild Horse Expansion projects.

generation limit that does not violate the TDG limits.

When the Mid-C system does not provide the necessary flexibility to balance the output from the Wild Horse wind project, PSE uses its thermal resources and market transactions to balance the system. For example, during spring 2008, PSE experienced insufficient Mid-C flexibility and managed wind output using its thermal resources. The thermal units were dispatched and operated at minimum, mid-point, and maximum generation levels to provide the flexibility to either increase or decrease generation.

Short term market transactions (spot or real time) are also an important component of wind integration within PSE's current portfolio, and they will continue to be a critical component into the future as PSE's wind portfolio expands and PSE's contractual share of the Mid-C hydro generation declines.

Q. How does the reduction in PSE's share of the Mid-C hydroelectric projects affect PSE's ability to integrate wind resources?

A. Consistent with standard operating practices, all of PSE's regulating reserves will continue to be provided by the AGC from PSE's share of Mid-C hydro generation. Even as PSE's contractual rights to the Mid-C hydro projects change and PSE's total capacity decreases, PSE believes it will be able to continue to reliably satisfy the regulating reserve requirements for rate year portfolio needs.

Due to expiring Mid-C hydro generation contracts, PSE's rate year share of the Mid-C hydro capacity is expected to average 726 MW, or 330 MW less than today's average 1,056 MW. PSE's share of the Mid-C hydroelectric projects output will decline due to the expiration of the old contracts and the beginning of the new contracts with the Public Utility District No. 1 of Chelan County, Washington ("Chelan PUD") for the hydroelectric output from the Rocky Reach and Rock Island dams. Specifically, the current Rocky Reach contract expires on October 31, 2011 and is replaced on November 1, 2011 with a contract that lowers PSE's Mid-C hydro capacity to 878 MWs. The Rock Island contract expires on June 7, 2012 which lowers the Mid-C Capacity even further to 673 MWs. When the replacement Rock Island contract begins on July 1, 2012, PSE's Mid-C hydro capacity share will increase to 720 MWs.

With reduced Mid-C capacity, however, PSE expects a greater number of instances in which Mid-C hydro is unable to provide the necessary wind generation following. In these circumstances, a combination of combined cycle combustion turbines ("CCCT") and simple cycle combustion turbines ("SCCT") may be called upon to provide wind generation following for Wild Horse. PSE modeling efforts indicate that CCCT annual generation will [redacted] slightly and SCCT generation will [redacted] relative to prior periods when PSE's share of Mid-C capacity was greater than it will be in the rate year.

These changes are a function of how PSE intends to modify operations to accommodate "following" requirements with less Mid-C capacity. If CCCT's are economically dispatched, they are considered to be available to provide following. A CCCT is more than likely to be dispatched at maximum output. If down following were needed in the same hour (wind generation may increase), the economically dispatched CCCT could meet that reserve need without adjusting the economically dispatched generation. If, however, up following is needed in an hour coinciding with an economically dispatched CCCT, the CCCT generation would be re-positioned and operated below its maximum output to provide up following in the event that wind decreased.

PSE intends to utilize SCCT plants in any situation where Mid-C, economically dispatched CCCTs, and market transactions are unable to meet PSE's wind integration requirements.

Q. Has PSE updated the costs of integrating its wind resources in the PSE BA from those included in the 2009 GRC?

A. Yes. PSE has completed a study of the costs to integrate wind resources in the PSE BA by studying the impact on regulation and following attributable to incremental wind generation being located in the PSE BA.

Q. What are the wind integration costs PSE incurs to integrate its wind resources?

A. To ensure that PSE has sufficient ability to increase or decrease generation to balance wind, PSE must hold capacity in reserve on the day-ahead, hour-ahead and within-hour time frames. The costs associated with providing the capacity to cover regulation, wind generation following, and any deviations between actual and scheduled generation is called wind integration costs.

PSE takes a least cost approach to integrating wind, which first utilizes its Mid-C hydro assets to ensure adequate balancing reserves. If constraints limit the flexibility of the Mid-C and market transactions are not available, then PSE's most efficient thermal resources are called upon to provide any remaining balancing capacity. PSE must also hold capacity in reserve for the day-ahead time frame for all of its wind resources as this service is not offered by BPA.

Table 6 lists the projected hour-ahead and within-hour opportunity cost of utilizing PSE's system in this manner to integrate all of its wind resources.

Table 6. 2011 GRC PSE Wind Integration Costs

Wind Project & Capacity	Day Ahead	Wind Integration	Total
Hopkins Ridge (156.6 MW)	[redacted]	In BPA Costs	[redacted]
Wild Horse (228.6 MW)	[redacted]	[redacted]	[redacted]
Wild Horse Expansion (44.0 MW)	[redacted]	[redacted]	[redacted]
Klondike III PPA (50.0 MW)	[redacted]	In BPA Costs	[redacted]
LSR Phase 1 (342.7 MW)	[redacted]	In BPA Costs	[redacted]
PSE Wind Integration Costs	**$2,516,579**	**$2,869,431**	**$5,386,010**

Q. What are the total wind integration costs PSE expects to incur to integrate its wind resources in the rate year?

A. The costs to integrate all of PSE's wind projects is $14.9 million as shown in the Table 7 below. These costs represent $9.5 million that PSE pays to BPA plus $5.4 million of costs incurred by PSE to integrate Wild Horse.

Table 7. Rate Year Costs to Integrate PSE Wind Resources

Wind Project & Capacity	Capacity Factor	Rate Year Generation	Balancing Authority	Total Costs	$/MWh
Hopkins Ridge (156.6 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
Wild Horse (228.6 MW)	[redacted]	[redacted]	PSE	[redacted]	[redacted]
Wild Horse Expansion (44.0 MW)	[redacted]	[redacted]	PSE	[redacted]	[redacted]
Klondike III PPA (50.0 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
LSR Phase 1 (342.7 MW)	[redacted]	[redacted]	BPA	[redacted]	[redacted]
Total Wind Integration Costs				$14,885,924	

Q. How does PSE integrate third-party wind?

A. In addition to balancing the output from Wild Horse, PSE, as a Balancing Authority, is required by FERC to manage the output from third-party wind projects within the PSE BA. Third-party wind projects are owned and operated by other entities and, although they are interconnected to the PSE BA, they serve load outside the PSE BA. As a balancing authority, PSE is responsible for delivering the scheduled amount of third-party wind to the sink BA regardless of actual wind power output. Effectively, third-party wind in the PSE BA is operationally indistinguishable from PSE-owned wind assets and is managed in a similar manner to Wild Horse. The Vantage wind project, located in Central Washington, with a nameplate capacity of 96 MW, is the only third-party wind project expected to be in the PSE BA. PSE is in the process before the FERC of seeking cost recovery of wind integration services provided to third-party wind resources.

VI. SALE OF EXCESS RENEWABLE ENERGY CREDITS

Q. What is a Renewable Energy Credit?

A. Renewable Energy Credits ("REC") represent the environmental attributes of renewable energy generation in the form of a marketable commodity which is separate from the attached energy value. Generally, one MWh of generation from an eligible renewable energy resource is equal to one REC.[9] There is a secondary market for the environmental attributes or RECs. 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. Under the Energy Independence Act, codified as RCW 19.285, large utilities such as PSE are required to obtain three percent of their electricity from renewable resources by 2012, nine percent by 2016, and fifteen percent by 2020. Because PSE has acquired several renewable energy resources that provide a supply of generation that exceeds the near-term renewable energy requirements, PSE will have excess RECs during the early years of the program. As the Energy Independence Act's renewable requirements increase, PSE's level of excess RECs will decline over time.

Q. Will PSE have any bundled REC transactions during the rate year?

A. Yes. PSE transacted with third parties in 2009 to monetize RECs generated by its

[9] Different states may have different incentive multipliers, such as the 1.2 multiplier in Washington if the renewable resource was constructed using qualifying apprentice labor.

renewable resources. PSE has sold bundled REC under these contracts and will continue to sell bundled RECs through 2015 (assuming the California Public Utility Commission approval is obtained). PSE's accounting for the revenues created by the sale of RECs was determined in Docket No. UE-070725.

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

A. No. PSE's bundled REC sales do not affect total power costs. Under these agreements, PSE delivers physical market-sourced power at the Mid-C hub as defined in the contracts. The buyers pay the contractual 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. Please see the Prefiled Direct Testimony of Mr. John H. Story, Exhibit No. ___(JHS-1T), for further discussion of the regulatory treatment of these revenues.

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

A. Yes. In February 2011, PSE entered into an agreement with the King County Solid Waste division of King County, Washington ("King County") to purchase all of the emission credits associated with the pipeline quality gas produced by the Cedar Hills Regional Landfill facility ("Cedar Hills"). In exchange, King County will receive a share of the net proceeds from the sale of qualified renewable gas or RECs produced by the Cedar Hills gas when used to generate electricity. This agreement, combined with the agreement to purchase the pipeline quality gas from Bio Energy (Washington), LLC ("Bio Energy"), entitles PSE to all the renewable attributes associated with the landfill gas generated by Cedar Hills. Although it is PSE's intent to monetize the renewable attributes of the pipeline quality gas, PSE has not yet signed agreements with third parties for sale of the Cedar Hills renewable attributes.

Q. How will PSE account for the pipeline quality gas generated by Cedar Hills?

A. In October 2008, PSE arranged to purchase all of the pipeline quality gas supply produced from Cedar Hills under a separate agreement with Bio Energy. PSE included the Cedar Hills landfill gas in the 2009 GRC rate year power costs. PSE is including the Cedar Hills landfill gas in this proceedings rate year power costs in the "Not in Models" calculation for mark-to-market gas contracts, which increases power costs $1,692,000. When this gas is sold, PSE will account for it as a sale of excess gas by crediting FERC 456, other electric revenues, with the sale price of the gas sold.

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

A. No. The revenues generated from the sale of the emission credits will be tracked separately and deferred in the deferred REC revenue 254 account. Payments to King County for their share of the net proceeds will reduce the deferred REC revenues.

VII. PROJECTED RATE YEAR POWER COSTS

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

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

A. PSE's projected rate year net power costs, including production O&M expenses, are $992.5 million. Please see Exhibit No. ___(DEM-5) for PSE's projected rate year net power costs. Please also see the Prefiled Direct Testimony of Mr. John Story, Exhibit No. ___(JHS-1T), for the adjustment of PSE's projected rate year power costs to test year levels.

Table 8. Projected Rate Year Power Costs

	($ in thousands)
AURORA	$595,095
"Not in Models"	$258,054
Production O&M	$139,305
Regulatory Disallowance	--
Projected Rate Year Power Costs	$992,454

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

A. PSE developed projected power costs for the rate year, which for this filing is May 1, 2012, through April 30, 2013. These projections are based on the information available to PSE during the preparation of the initial filing in this proceeding, and except as noted, are consistent with PSE's prior rate cases.

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

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

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

Q. What is the AURORA hourly dispatch model?

A. The AURORA hourly dispatch model is a fundamentals-based production cost model that simulates hourly economic dispatch of PSE's generation resource portfolio within the Western Electricity Coordinating Council ("WECC") region. AURORA produces a forecast of the variable operating costs for PSE's generating resources as well as a forecast of regional power prices. Changes to PSE's assumptions in, and inputs to, the AURORA model since PSE's last general rate case for projecting rate year power costs are described below.

Q. Were there changes made to the AURORA hourly dispatch model since the 2009 GRC?

A. Yes. EPIS, Inc. ("EPIS"), the developer of the AURORA hourly dispatch model, provides periodic software and database updates. The software version of AURORA used in this filing is 10.1.1005. The database used is the North American Database 2010.02 ("2010.02 Database"), which EPIS issued on December 29, 2010. EPIS updated the resource, demand, financial, and regional data within the 2010.02 Database to reflect more recent data, information and economic conditions than those included in the AURORA database used in the 2009 GRC.

Q. Do the regional loads included in 2010.02 Database consider the current recession and economic downturn?

A. Yes. The 2010.02 Database reflects a decrease from the 2009 GRC AURORA database in the regional loads AURORA uses to balance against regional resources. The 2010.02 Database reflects a regional load decrease of approximately 10 percent in both 2012 and 2013 from the regional load in the 2009 GRC AURORA database.

Q. Is AURORA version 10.1.1005 the most recent version of AURORA available?

A. No. EPIS recently issued version 10.1.1027 on April 13, 2011 – long after PSE had begun its power cost modeling for this filing.

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

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

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

A. Consistent with prior proceedings, PSE used the forward electric market prices generated by the AURORA hourly dispatch model.

B. Power Cost Assumptions

1. Rate Year Power Supply Resources

Q. Is PSE's rate year power supply portfolio for this proceeding different from the pro forma power cost portfolio approved in the 2009 GRC?

A. Yes. A number of changes to PSE's portfolio have already occurred or will occur by or during the rate year (May 2012 through April 2013) for this case. Specifically, PSE's rate year power costs:

(i) include LSR Phase 1 for the entire rate year because it is expected to be in-service in mid-April 2012. LSR Phase 1 will have 149 turbines and provide 342.7 MWs of capacity. The rate year includes 892,000 MWhs of wind generation using the rate year average capacity factor of [redacted] percent. Please refer to the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT) for a discussion of LSR Phase 1. PSE is requesting a prudence determination in this proceeding for this resource;

(ii) include the four-year and two-month PPA negotiated with Iberdrola Renewables for 100 MW of winter capacity associated with the Klamath peakers (the "Klamath Peakers 5-Year PPA"). Please refer to the Prefiled Direct Testimony of Ms. Aliza Seelig, Exhibit No. ___(AS-1HCT), and the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT), for a discussion of the Klamath Peakers 5-Year PPA. PSE is requesting a prudence determination in this proceeding for this resource;

(iii) reflect the 4-year winter on-peak power purchase agreement with Barclays Bank PLC for an additional 75 MW of winter-only capacity effective November 1, 2011. The Commission issued a prudence determination for this contract in the 2009 GRC;

(iv) reflect the new twenty-year contract with Chelan PUD that the Commission issued a prudence determination in PSE's

2006 general rate case, Docket Nos. UE-060266 & UG-060267 (consolidated) (the "2006 GRC") for:

(a) 25 percent of the Rocky Reach Hydroelectric Project ("Rocky Reach") output effective November 1, 2011. This 25 percent share is a reduction from the 38.9 percent share contract which expires on October 31, 2011 and will provide PSE with reduced capacity of 320 MW (as compared to the previous contracted 498 MW) and approximately 176 aMW of energy and

(b) 25 percent of the Rock Island 1&2 Hydroelectric Project ("Rock Island") output effective July 1, 2012. This 25 percent share is a reduction from the 50 percent share contract which expires on June 7, 2012 and will provide PSE approximately 156 MW of capacity (as compared to the previous contracted 312 MW) and approximately 96 aMW of energy;

(v) reflect net lower generation and costs under the Mid-C contract terms with Public Utility District No. 2 of Grant County, Washington ("Grant PUD"). Specifically, PSE's share of the output from the Wanapum Development and Priest Rapids Development Hydroelectric Projects decreased from those included in the 2009 GRC (1.29 percent and 0.64 percent in 2010 and 2011, respectively), to 0.64 percent of the combined Priest Rapids Hydroelectric Project projection for 2012 and 2013;

(vi) reflect the expiration of:

(a) the Priest Rapids Displacement Product, an approximately 29 MW block of low cost power purchased under PSE's contract with Grant PUD on September 30, 2011;

(b) the 245 MW capacity contract with Tenaska Washington Partners, LP on December 31, 2011;

(c) the 145 MW capacity contract with March Point Cogeneration Company on December 31, 2011;

(d) the 22.9 MW capacity Municipal Steam Waste contract with the City of Spokane on December 31, 2011;

(e) the 4-year winter 150 MW on-peak power purchase agreement with [redacted] on February 29, 2012;

(f) the 97 MW capacity contract with Northwestern Energy on December 29, 2010;

(g) the agreement between PSE and Occidental Energy Marketing, Inc. for 16,884 MMBtu per day of gas transportation between the Rockies region and Sumas and 6,600 MMBtu per day at Sumas on June 30, 2011 and assumed 20,000 MMBtu per day at Sumas at $0.20 per MMBtu per day to replace the capacity after the contract's expiration; and

(h) the 5 MW capacity PPA with Northern Wasco County People's Utility District on December 31, 2012;

(vii) reflect the contracts executed under PSE's Schedule 91 Tariff, "Cogeneration and Small Power Production";

(viii) assume the extension of the Schedule 91 contract with Port Townsend Paper Corporation ("Port Townsend Paper") through at least the end of the rate year (the current contract extension expires June 30, 2011 and PSE and Port Townsend Paper are negotiating a longer-term contract under Schedule 91);

(ix) reflect the redevelopment of the Snoqualmie Falls Hydroelectric Project and the planned outages of Powerhouse #1 (12 MW capacity) and Powerhouse #2 (34 MW capacity) for the entire rate year;

(x) reflect the planned redevelopment of the Electron Hydroelectric Project beginning March 1, 2013;

(xi) assume the continuance of the Asset Management Agreement with Cabot Oil & Gas Marketing Corporation involving 6,704 MMBtu per day of deliverability and 140,622 MMBtu of storage capacity past its initial 3-year term ending April 1, 2012, as it continues year-to-year thereafter, subject to timely termination notice by either party;

(xii) include the recently acquired 25,853 MMBtu per day of Westcoast pipeline deliverability (released from BNP Paribas) between Station 2 and Huntingdon (Sumas). The rate year power costs reflect a capacity charge of $4.6 million offset by a discount received from BNP Paribas of $0.5 million per year, for a rate year cost of $4.1 million. For further discussion, please see the Prefiled Direct Testimony of Mr. Clay Riding, Exhibit No. ___(RCR-1CT);

(xiii) assume renegotiation of existing Northwest pipeline contracts for Sumas deliverability for 25,000 MMBtu per day effective October 1, 2012 and for 25,000 MMBtu per day effective April 1, 2013. For further discussion, please see the Prefiled Direct Testimony of Mr. Clay Riding, Exhibit No. ___(RCR-1CT);

(xiv) include 28,928 MMBtu per day of gas for power pipeline capacity from Stanfield to Deer Island, Jackson Prairie and Bellingham with a rate year capacity charge of $4.2 million. For further discussion, please see the Prefiled Direct Testimony of Mr. Clay Riding, Exhibit No. ___(RCR-1CT);

(xv) reflect a name change and the expiration of the PPA with Sempra Energy Trading LLC ("Sempra) to J.P. Morgan Ventures Energy Corporation ("JP Morgan"). In April 2011, Sempra assigned to JP Morgan, and JP Morgan accepted the assumption of, this PPA to deliver 75 MW of power in the first, third and fourth quarters and 25MW of power in the second quarter, at a flat price until the PPA expires on March 31, 2013;

(xvi) reflect the change in the name of the 50 MW PPA with Credit Suisse Energy, LLC ("CSE") to Shell Energy North America (US), L.P. ("Shell"). CSE divested its power trades in the WECC region, and, as of December 3, 2009, Shell is obligated to perform under this contract;

(xvii) reflect changes in costs to integrate PSE's wind generation (intermittent renewable resources) into PSE's power portfolio, as discussed above; and

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

2. Projected Hydro Availability

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

A. In consideration of the 2009 GRC Order, which noted that future rate cases should include more recent hydro data,[10] PSE has used the average of the 70-year Mid-C streamflow history from 1929 through 1998 to project power costs for the rate year. Although power costs set in rates since PSE's 2004 general rate case docket UG-040640 & UE-040641 ("2004 GRC") reflected the 50-year average Mid-C streamflow history from 1929 through 1978, the Commission stated as follows in the 2009 GRC Order:

> Inasmuch as the Company has access to at least some of the more recent data, its power cost evidence in future rate proceedings should include consideration of that data. . . .
>
> . . . . However, we have stated above our preference for using the longest span of years possible.[11]

To be consistent with the Mid-C historical data, PSE used the same 70-year historical west side streamflow records for projections related to PSE's owned hydropower on the west side of the Cascade Mountains.

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

[11] *Id.* at ¶¶ 124-125.

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

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

Q. How does the 70-years of hydro generation versus 50-years of hydro generation impact rate year power costs?

A. Using the 70-year hydro data set reduces PSE's rate year hydro generation by nearly 23,000 MWhs from the 50-year data set. The AURORA rate year power costs increased $712,000 due to the lower hydro generation.

Q. Do the AURORA model databases used to determine the underlying power costs for this rate proceeding include the seventy years of hydro data?

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

3. <u>Natural Gas Prices</u>

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

A. As the Commission noted in its final order in the 2006 GRC, the update for gas costs is "well-established" and should be "straightforward, mechanical and non-controversial."[12] Consistent with this order, PSE used a three-month average of daily forward market prices for the rate year for each trading day in the three-month period ending April 12, 2011. PSE input these data into the AURORA hourly dispatch model for each of the months of the rate year.

In addition, consistent with prior general rate cases, all previously executed rate year short term power and gas contracts at the price cut off date, April 12, 2011, are included in the rate year power costs. Fixed-price short term rate year power contracts are included within the AURORA hourly dispatch model and fixed-price rate year contracts for natural gas for its power portfolio are adjusted outside of the AURORA hourly dispatch model in the "Not in Models" calculations. An adjustment is also included in the "Not in Models" calculation for premiums and discounts associated with any power and gas for power contracts priced at plus or minus index. These calculations require updating whenever natural gas prices are changed or updated during a proceeding.

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

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

A. The gas price input to the AURORA hourly dispatch model represents a three-month average of the forecast *market* rate year gas prices at a certain point in time (in this case, April 12, 2011). Given PSE's extensive hedging protocol, which includes a programmatic component that requires a specified amount of hedging be done each month, rate year power costs must reflect PSE's actual fixed price gas and power rate year contracts as of that date. Hedges are included because forecast rate year power costs consist of two components: (i) costs related to *actual* commitments; and (ii) *forecast market costs* dependent upon the AURORA modeled operational and market fluctuations. The adjustment requires calculating the difference between the three-month average monthly cost of natural gas at the pricing cut-off date (April 12, 2011 in this proceeding) and the monthly average cost of natural gas hedges that have been transacted for the rate year as of the same cut-off date.

For each month of the rate year, this difference is multiplied by the volume of the gas for power hedges transacted for the rate year. The resulting amount represents the "mark-to-market" benefit or cost that is included in the power cost forecast. Including the fixed-price power contracts within the AURORA hourly dispatch model and marking both the fixed-price gas for power and index-based power and gas for power contracts to the three-month average rate year gas price input in the "Not in Models" calculation is consistent with the methodology used by PSE in its 2006 GRC, 2007 PCORC, 2007 GRC and 2009 GRC.

Q. How do projected gas prices inputs into AURORA for this proceeding compare with those in the 2009 GRC?

A. Use of a single price can be misleading because there are different projected gas prices for each month of the rate year and for the different trading hubs from which PSE purchases gas. Additionally, these prices do not consider the impact of the fixed price gas contracts at the price cut off date which may significantly change the average gas price. For purposes of comparison, however, the average gas price at the Sumas trading hub for the rate year is $4.72 per MMBtu (for the three months ended April 12, 2011), which is $1.25 per MMBtu *lower* than the average $5.97 per MMBtu price included in the 2009 GRC (for the three months ended August 13, 2009). Table 9 below presents average rate year gas price comparisons.

Table 9. Average Annual Rate Year Gas Prices

Rate Case =>	2011 GRC	2009 GRC	2007 GRC
3-Mo average at =>	4.12.11	8.13.09	3.11.08
Rate Year =>	May 12 – Apr 13	Apr 10 – Mar 11	Nov 08 – Oct 09
Sumas	$4.72	$5.97	$8.51
Change from Prior	($1.25)	($2.54)	--

Q. What factors have affected the decrease in natural gas prices from the last rate proceeding?

A. In general, it appears that prices have declined from the 2009 GRC because of growing confidence in the future supply of natural gas, specifically shale gas. During the three month period ending August 13, 2009 (used to determine the prices in the 2009 GRC), one key market fundamental driver reflected in forward prices was the possibility of a steep decline in production from the reduction in operating gas rigs. The actual outcome, however, has been quite different. Producers have gained more experience in applying new technology–such as horizontal drilling–to explore and discover shale gas; costs of gas production in the United States have declined–enabling productivity to increase; and the market has gained confidence that production will be maintained in a low-price environment.

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

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

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

Although there is no readily available forward gas price for Station 2, PSE has recently contracted to acquire a forward price forecast of the basis differential between the Alberta Energy Company ("AECO") and Station 2 gas hubs (AECO is one of the gas hubs acquired from Kiodex for input to AURORA). Although PSE has not yet received this forward price curve,[13] PSE has used the average of four broker quotes for the forward basis differential between the AECO trading hub and Station 2 in order to determine the rate year gas prices at Station 2 for this filing. The calculated rate year average forward price for Station 2 is $4.20 per Dth. The calculation of the Station 2 basis differential is discussed in the "Not in Models" section of my testimony.

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

A. Yes. PSE intends to update its projected power costs with updated gas price projections because the factors that impact natural gas prices are constantly changing, forward market prices quickly become "stale," and their predictive power with respect to actual future prices decreases with time. Establishing rate year gas prices based on the average of the forward prices for the rate year for a three-month period of time closer to the beginning of the rate year will provide a more accurate projection of rate year gas prices. Therefore, PSE will adjust its requested power costs with updated forward market data prior to rates becoming

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[13] PSE expects to have the contracted forward price forecast of the basis differentials between AECO and Station 2 in time to provide them in the updated power cost filing.

effective. This would also include an update to the short-term fixed-price power contracts that are an AURORA input and the other index-based power and gas for power contracts that are an adjustment included in the "Not in Models" calculation. In addition, some "Not in Models" adjustments are dependent on the AURORA generation and prices. These adjustments update automatically in the MS Excel files whenever a new AURORA model run download is included in the files.

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

A. PSE intends to provide all parties with updated power cost information–including updated average gas prices–in a manner and at a date that enables all parties adequate time to review the proposed changes. In this regard, PSE proposes to file updated rate year power costs to reflect more recent three month average gas prices two to three months prior to the other parties' response filings, which is estimated to be August 2011.

Q. How do more recent forecast rate year natural gas prices compare to the three-month average at April 12, 2011?

A. As of May 17, 2011, the three-month average rate year Sumas natural gas price has increased to $4.79 per MMBtu, an increase of $0.07 per MMBtu from the $4.72 per MMBtu used to determine the prefiled rate year power costs in this proceeding.

4. <u>Load Forecast</u>

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

A. PSE used the most current load forecast, F2011, as the rate year demand input to the AURORA model. The F2011 load forecast was approved by PSE's Energy Management Committee in April 2011. The delivered electric load forecast, net of demand-side resources (conservation), for the May 2012 through April 2013 rate year is 23,172,444 MWhs, or 2,645 average MWs ("<u>aMW</u>").

Q. Is the F2011 load forecast the same as that used in PSE's 2011 March 31, 2011 draft Integrated Resource Plan?

A. No. PSE's March 31, 2011, draft 2011 Integrated Resource Plan (the "<u>IRP</u>") used the then-current load forecast–the F2010 load forecast–in its underlying analytics. The reason for this is twofold: (i) the load forecast is a central component of the IRP analyses; and (ii) the IRP takes up to 18 months to complete. As noted above, the F2011 load forecast was approved in April 2011, shortly after the draft 2011 IRP was issued. Although this provided no time to integrate the F2011 load forecast into the 2011 IRP, it did provide enough time to use the F0211 load forecast in this rate proceeding.

Q. Please compare the F2010 and the F2011 load forecasts.

A. The F2011 load forecast for the rate year May 2012 through April 2013 is

168,953 MWhs lower (19 aMWs) than the F2010 load forecast used in the 2011 IRP, which is estimated to decrease power costs approximately $6.6 million.

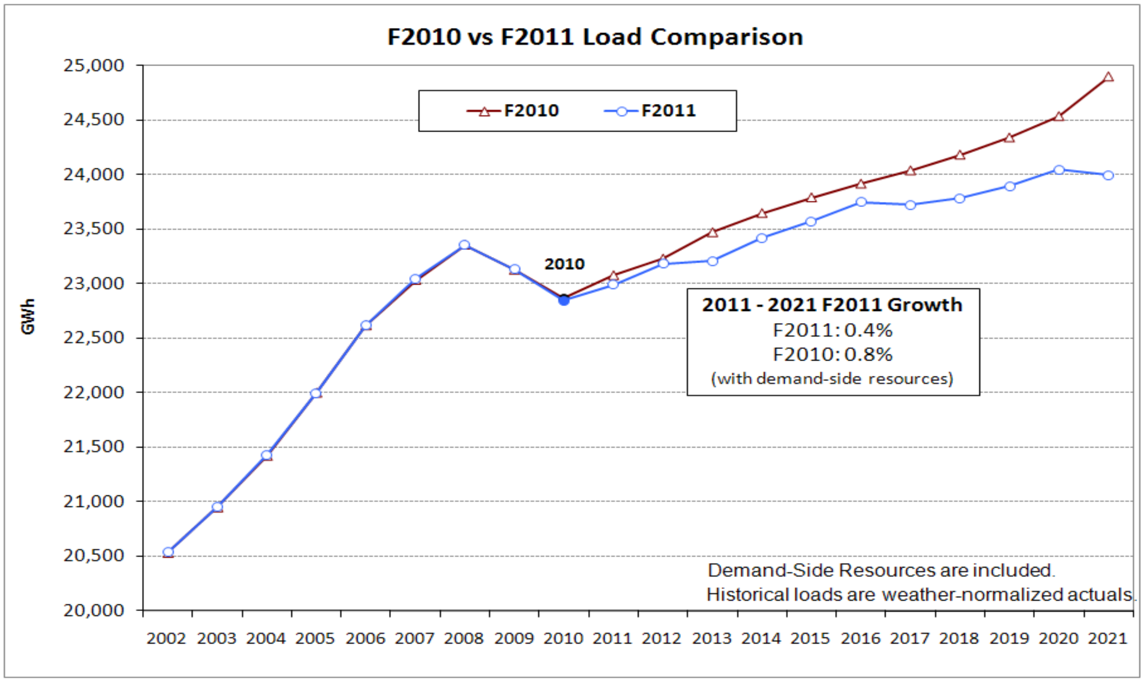
Table 10. Load Forecast Comparisons

Load Forecast	Use	Rate Year (May 12 – Apr 13)		Change from Prior		
		MWhs	aMW	MWhs	aMW	%
F2008R	2009 GRC	23,208,055	2,649	--	--	--
F2010	2011 IRP	23,341,397	2,665	133,342	15	0.57%
F2011	2011 GRC	23,172,444	2,645	(168,953)	(19)	-0.72%

Q. What are the underlying changes between the F2010 and the F2011 load forecast?

A. The major change in the F2011 load forecast from the F2010 load forecast during the rate year is the updated economic-demographic forecast. The F2011 forecast uses an economic-demographic forecast that presents a slower economic recovery than the economic forecast developed in the F2010 forecast. The F2011 forecast expects unemployment to decline more slowly and the housing market to recover more slowly than the F2010 forecast predicted. The relatively higher unemployment and slower housing market growth in the F2011 load forecast impact both use per customer and the customer growth rates. A smaller source of change during the rate year is an increased estimate of conservation.

The below graph compares the annual load forecasts from the F2011 load forecast used in this proceeding to the F2010 load forecast used in PSE's 2011 IRP.



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

Q. Has PSE included adjustments in the "Not in Models" that are consistent with the adjustments approved in the 2009 GRC?

A. Yes. Except for the basis differential calculation for Station 2 and other items discussed in more detail below, PSE has included adjustments in the "Not in Models" calculation that reflect the 2009 GRC order. Although PSE disagrees with the Commission's determination that power costs should be reduced to reflect a benefit for the Cabot Asset Management Agreement, PSE has included the Commission's intended power cost reduction in this rate proceeding.

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

A. Yes. Although the "Not in Models" adjustments are consistent with those presented in the 2009 GRC, below is a listing of PSE's proposed additions and changes to the "Not in Models" adjustments:

(i) PSE has included the costs for the new resources discussed above that are not included in the AURORA modeled power costs, specifically:

- "Not in Models" includes $10.7 million for fixed and variable transmission and wind integration costs for the LSR Phase 1. These costs are net of a $2.9 million credit for interest to be received from BPA related to PSE's Large Generator Interconnection Agreement deposit. LSR Phase 1 costs and the transmission deposit are discussed in the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT) and the Prefiled Direct Testimony of Mr. John H. Story, Exhibit No. ___(JHS-1T), respectively;

- "Not in Models" includes $4.2 million for the Klamath Peakers 5-Year PPA, which represents transmission costs, capacity payments and O&M charges, as described in the Prefiled Direct Testimony of Ms. Aliza Seelig, Exhibit No. ___(AS-1HCT) and the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT); and

- "Not in Models" reflects an additional 28,928 MMBtu per day and 25,853 per day of gas for power transportation at Stanfield and Station 2, respectively. The cost of the Stanfield transportation is $4.2 million and of the Station 2 transportation is $4.6 million. These gas transportation contracts are discussed above and in the Prefiled Direct Testimony of Mr. Clay Riding, Exhibit No. ___(RCR-1CT);

(ii) Mercury and lime variable costs for Colstrip units 1 through 4 have been included in the "Not in Models" adjustments in past rate proceedings. These $4.4 million of costs, however, vary with the quantity of coal burned and have been more appropriately included in the AURORA model variable costs. These costs are discussed in the

Prefiled Direct Testimony of Mr. Michael Jones, Exhibit No. ___(MLJ-1T);

(iii) Rate year costs associated with the Mid-C contract reflect the costs under the new Chelan PUD contract, which, as discussed above, was approved in the 2006 GRC. These include additional contractual obligations under the Chelan PUD Power Sales Agreement for the Rocky Reach and Rock Island Projects, which include amortization of $7.1 million for the $89 million capacity reservation charge, $0.3 million for the funding of the working capital charge and $0.1 million for funding of the coverage fund charge. Also included are $4.3 million for the transmission service requirements under the new contract beginning November 1, 2011;

(iv) PSE determined the forward market price used to calculate the mark-to-market on gas transportation capacity for the Station 2 gas hub by using market quotes from four independent brokers on April 11, 2011. In the 2009 GRC order, the Commission accepted the use of historical basis differentials to forecast the Station 2 forward gas price[14]. The mark-to-market adjustment using broker quotes for the Westcoast (Station 2) pipeline reduce power costs $3.3 million;

(v) Included BPA's rate increase effective October 1, 2011, as discussed above;

(vi) Rate year power costs include $0.6 million for the incremental cost of distillate fuel used to test PSE's combustion turbines under its Power Generation Combustion Turbine Fleet Distillate Fuel Management Program that are above market prices; and

(vii) Rate year costs include a pro forma $1.3 million credit for estimated transmission reassignments as discussed above.

[14] The mark-to-market adjustment using a historical basis differential from the 2010 test year would be a credit of $8.1 million;

Q. Please explain the "Not in Models" adjustment for the Westcoast pipeline basis differential.

A. PSE has contracted rights on the Westcoast pipeline that provide the ability to transport 73,183 MMBtu per day of gas purchased at the Station 2 gas hub in Canada to the Sumas gas hub. Since the AURORA model uses the input Sumas gas prices for PSE's gas fired generators dispatch and power costs, PSE must separately calculate the cost difference between Station 2 and Sumas, also known as the "basis differential", as an adjustment in the "Not in Models"

Kiodex, PSE's contracted provider of forward price curves, does not provide forward price curves for Station 2. In rate cases prior to the 2009 GRC, PSE determined the forward price for Station 2 by obtaining quotes from brokers for the difference between the forward price curve for AECO and the Station 2 hub. In the 2009 GRC, intervening parties argued that the basis differential should be based upon available historical basis differentials. In the Final Order the Commission noted that:

> The ICNU/Staff argument that the Company's reliance on a single broker quote is insufficient to estimate the rate-year basis differential is persuasive. We also find merit in the Company's argument that basis differential should be based on forward market information, as are fuel gas prices.[15]

Although the Commission accepted the use of historical basis differentials based on the facts presented in the 2009 GRC, PSE proposes to use for this proceeding

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[15] 2009 GRC Final Order at ¶ 141.

forward basis differentials from a third party contractor to determine the forward price for the Station 2 hub. As noted above, PSE is in process of acquiring this information and has included in this direct filing the average of four broker quotes as the proxy for the forward basis differential between Station 2 and Sumas. An adjustment to reflect the benefit associated with PSE's acquisition of natural gas pipeline capacity on the Westcoast Energy System is included in "Not in Models". Rate year power costs have been reduced $3.3 million to reflect the basis differential between gas sourced at Station 2 and gas delivered at Sumas.

Q. What is the mark-to-market adjustment for gas for power contracts included in "Not in Models"?

A. As discussed above, rate year gas for power and power contracts transacted by April 12, 2011, are reflected in power costs. Rate year gas for power contracts at April 12, 2011, were compared to the 3-month average gas prices at the same date, resulting in a mark-to-market expense adjustment of $14.1 million.

Q. Please explain the "Not in Models" adjustment for the Power Generation Combustion Turbine Fleet Distillate Fuel Management Program ("<u>Distillate Fuel Program</u>").

A. PSE has put in place a Distillate Fuel Program to ensure its combustion turbines which have capacity to generate with distillate (oil) are available and able to generate with oil when called upon to meet peak or intra-day demand where firm transport of natural gas may not be available. In addition, this program ensures an adequate level and quality of fuel oil inventory is available at PSE's Whitehorn, Encogen, Fredonia and Frederickson gas generating facilities. Under this program, each combustion turbine will generate with oil for an hour every month during the winter months of November through March. The $0.6 million of "Not in Models" costs represents the cost of running the units uneconomically, which is the difference between the cost of running the combustion turbines with distillate under the program and the average market price of power for each of the winter months.

VIII. PRODUCTION OPERATIONS AND MAINTENANCE EXPENSE

Q. How has PSE prepared its forecast of production operations and maintenance expense for the rate year?

A. PSE developed the rate year production operations and maintenance ("O&M") expense in accordance with the 2009 GRC Order, utilizing calendar year 2010 test year data and making certain pro forma adjustments as previously allowed by the Commission and as discussed below.

Q. Are there any notable additions or proposals to the rate year production O&M as compared to the 2009 GRC?

A. Yes. PSE is

(i) including the new maintenance service contracts with Vestas-America ("Vestas") for Hopkins Ridge and Wild Horse in its pro forma rate year wind maintenance costs;

(ii) proposing a pro forma adjustment to incorporate projected wind royalty payments to align with the pro forma wind generation forecasts;

(iii) retaining the test year level of major maintenance amortization for its fleet of gas fired turbines with third party maintenance agreements; and

(iv) considering the test year major maintenance costs to be a normal level of production O&M expense to maintain its gas fired turbines and components without third party maintenance contracts.

A. Wind Resource Maintenance Costs

Q. How is routine and corrective maintenance provided for the wind turbines?

A. PSE's wind turbines are maintained by the manufacturer, Vestas, in accordance with the terms of five-year service agreements. PSE has three service agreements in place -- one each for Hopkins Ridge,[16] Wild Horse, and the Wild Horse Expansion. The original five-year service agreement for Hopkins Ridge expired on November 27, 2010, and the Wild Horse and Wild Horse Expansion service agreements will expire December 22, 2011 and November 6, 2014, respectively. The maintenance costs for the LSR Phase 1 project are discussed in the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT).

Q. What steps did PSE take to evaluate wind turbine service options prior to expiration of the original service agreements?

A. In 2009, PSE engaged Navigant Consulting ("Navigant"), an internationally

[16] Hopkins Ridge includes the Hopkins Ridge Infill.

recognized management consulting firm, to evaluate the current market for wind turbine services. Navigant studied four service alternatives for PSE's wind projects: (1) hire a qualified third-party service provider; (2) PSE self-perform services; (3) continue with Vestas services; and (4) a hybrid of PSE and a third-party service provider. These alternatives were evaluated on a matrix of cost, capabilities, quality, risk, and cultural fit criteria.

Q. What did Navigant conclude and recommend as a result of its analysis?

A. Navigant scored each service alternative against the evaluation criteria mentioned above (cost, capabilities, quality, risk, and cultural fit). Based on its analysis of the cost of each option, the impact of service risks, and organizational capabilities of each alternative service provider, Navigant recommended Vestas as the most qualified and lowest reasonable cost wind turbine service provider for PSE's existing wind turbine fleet. Given the rapid pace of change in the wind industry and PSE's own growth as a wind turbine operator, Navigant also recommended revisiting the available service alternatives in five years.

Q. Did PSE pursue Navigant's recommendation with Vestas?

A. Yes. PSE engaged Vestas in negotiation of a new maintenance service contract, which culminated in a Master Service Agreement covering both Hopkins Ridge and Wild Horse (the latter upon expiration of its original contract on December 22, 2011). The new Master Service Agreement provides uniform terms and conditions for PSE's existing Vestas fleet (today there are three separate agreements with differing terms), includes all scheduled and unscheduled maintenance services, all parts and labor, troubleshooting and engineering support, and provides warranty-like coverage for any existing or future equipment defects and corrective maintenance. The agreement has a five year term giving PSE a unilateral option to renew for a second five year term, provides fixed annual base pricing and variable annual production pricing as an incentive for Vestas to perform. The agreement also includes provisions for liquidated damages on the delayed delivery of needed spare parts, an option for PSE to terminate for convenience, and a mechanism allowing any new wind projects using Vestas turbines to gain service coverage when they are commissioned.

Q. What does the new Master Service Agreement cost for Hopkins Ridge and Wild Horse?

A. The Master Service Agreement cost for Hopkins Ridge and Wild Horse includes an annual fixed cost plus a variable fee. The contracts' fixed and variable fees escalate every January 1 with changes in the Gross Domestic Product Implicit Price Deflator benchmark rate. For 2012 and 2013, the annual fixed cost per turbine is forecast to be $[redacted] and $[redacted], respectively. The variable fee per MWh generated is $[redacted] and $[redacted], respectively. The estimated production O&M cost of these new agreements for the rate year is; $4.7 million for Hopkins Ridge and $6.7 million for Wild Horse. The total Vestas contract costs for the rate year under the MSA and the other agreement for the Wild Horse Expansion, including applicable sales taxes, is $13.6 million, or a $3.1 million increase from the test year cost of $10.5 million.

B. Wind Resource Royalty Costs

Q. Please explain PSE's proposed adjustment to wind royalty expense.

A. Wind turbine production royalties represent variable dollar per MWh fees paid under contract to project stakeholders. These fees are directly matched with the generation from PSE's wind turbines. As wind generation increases, wind royalties increase and power costs decrease, and vice versa. In respect of the matching principle discussed in the 2009 GRC Order, it is appropriate to pro form the royalty costs based upon the wind generation included in the rate year power portfolio. In this regard, the rate year royalty expense for PSE's wind facilities have increased $0.4 million - $0.1 million for Hopkins Ridge and $0.3 million for the Wild Horse wind turbines – for a rate year total of $3.7 million.

Q. Do the wind turbine production royalty payments reflect contract increases?

A. Yes. In accordance with the terms of PSE's development and land lease agreements with project stakeholders, the annual royalty rate paid per MWh of energy production is subject to an annual inflationary increase.

C. Gas Fired Turbine Production O&M

Q. How is PSE proposing to recover O&M costs for its gas fired turbines?

A. PSE considers its test year level of production O&M expense to represent a normal level of operating expenses for its owned gas fired turbines and the plant operators budget (except for major maintenance costs) to represent the rate year level of production O&M for its jointly owned gas fired turbines:

(i) Major Maintenance Costs:

(a) For plants with Long Term Service Agreements ("LTSA") and Contract Service Agreements ("CSA"), the test year major maintenance amortization reflects amortization of known and measurable major maintenance events. Plants with LTSA and CSAs are the Frederickson 1 Generating Station ("Freddy 1"), Goldendale, Mint Farm and Sumas; and

(b) For plants without maintenance contracts, the major maintenance costs incurred in the test year represent known and measurable costs which are indicative of a normal level of maintenance expense.

(ii) Other Production O&M costs:

(a) The Goldendale, Mint Farm, Encogen, Sumas, Frederickson, Fredonia, Whitehorn and Crystal Mountain facilities rate year production O&M is based upon actual test year production O&M expense; and

(b) The jointly-owned Freddy 1 rate year costs are based upon projected rate year operating costs provided by the plant operator, Capital Power Corporation ("Capital Power"), and the rate year expected generation.

Q. Please describe the costs associated with the CSA and LTSA contracts.

A. PSE has a CSA or an LTSA covering major maintenance events with General Electric ("GE") for Goldendale, Sumas, Mint Farm and Freddy 1. Generally, these contracts call for a monthly fixed fee, a variable factor fired hour fee and periodic milestone payments. In the case of Goldendale and Freddy 1, PSE also pays a variable compressor turbine rotor and casing variable factor fired hour fee.

The Mint Farm LTSA payments are based on variable factor fired hour fees and periodic milestone payments (there are no fixed fees).

Q. How does PSE account for the costs under these contracts?

A. PSE uses the deferral method of accounting for planned major maintenance, as set forth within the American Institute of Certified Public Accountants Audit and Accounting Guide for Airlines, without any dollar limit. The contract cost components are accounted for as follows:

(i) Fixed Monthly Fees and variable compressor turbine rotor and casing fees are related to ongoing support services received from GE and are charged to current maintenance expense;

(ii) Variable Factor Fired Hour Fees are allocated between current (Mint Farm only) and prepaid maintenance expense, capital and inventory accounts. The allocations are based on the ratio of the field service costs plus refurbishment costs to expense and capital costs;

(iii) Prepaid capital and inventory are capitalized at the time of the planned event and depreciated over the remaining life of the plant; and

(iv) Prepaid Expense is amortized to expense over the expected period of time until the next planned event.

Q. How is PSE recovering the costs of these contracts in its current rates?

A. In the 2009 GRC, the Commission accepted the principle of using a deferral methodology for major plant maintenance expenses yet did not decide how costs for plants without maintenance contracts would be recovered.[17] In accepting PSE's rate year production O&M expenses, PSE recovered a restated level of amortization for major maintenance contracts but no amount for major maintenance expenses for units without contracts.

Q. What major maintenance expense is included in this rate proceeding?

A. Major maintenance expense associated with generation facilities that have a CSA or LTSA is equal to the amortization of the deferred major maintenance costs that have been incurred in the test year. Major maintenance amortization expense included in the rate year is $1.1 million. Major maintenance costs for gas fired turbines without maintenance contracts are expensed in the year incurred. Non-contract major maintenance expense incurred in the test year and included in the rate year are $8.2 million.

D. Forecast Production O&M Costs

Q. What is PSE's forecast of production O&M for the rate year?

A. The rate year production O&M costs are forecast to be $137.6 million, an increase of $25.4 million from the 2009 GRC production O&M costs of $112.2 million. The production O&M increase is attributed to the addition of the LSR Phase 1 wind facility, increased coal costs and major maintenance expenses for units without contracts. PSE developed the rate year production O&M forecast in

[17] 2009 GRC Final Order at ¶ 163.

accordance with the 2009 GRC Order, except as noted above. Please see Exhibit No. ___(DEM-6) for a summary of the rate year production O&M costs.

Q. Please summarize PSE's forecast of production O&M costs in this filing.

A. In estimating rate year costs, PSE has made the following adjustments to its test year (January 1, 2010 through December 31, 2010) production O&M costs:

(i) PSE added $10.9 million of projected rate year production O&M costs for the LSR Phase 1 wind facility. Cost projections for LSR Phase 1 are discussed in the Prefiled Direct Testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT);

(ii) As discussed above, PSE projected rate year production O&M costs under the Vestas and royalty contracts for the Hopkins Ridge, Wild Horse and Wild Horse Expansion Wind Projects of $13.6 million and $3.7 million, respectively;

(iii) projected rate year operating costs of $4.3 million for Freddy 1 based on projected costs provided by the plant operator, Capital Power and the rate year expected generation. In May 2009, Capital Power acquired all power generation assets of EPCOR Utilities, Inc., which included Freddy 1. Major maintenance costs are normalized or deferred as discussed above;

(iv) projected $0.6 million for O&M costs associated with the relicensing requirements for the Snoqualmie Falls Hydroelectric Project;

(v) projected $4.9 million for O&M costs associated with the FERC relicensing of the Baker River Hydroelectric Project;

(vi) assumed the extension of the assignment between PSE's Core Gas book and PSE's power book for Jackson Prairie storage service through the end of the rate year as discussed in the prefiled direct testimony of Mr. Clay Riding, Exhibit No. ___(RCR-1CT); and

(vii) projected $42.3 million for Colstrip O&M costs based upon forecasted O&M costs provided by the plant operator, PPL Montana and the adjusted test year Colstrip settlement costs. Please see the prefiled direct Testimony of Mr. Mike Jones, Exhibit No. ___(MLJ-1CT) for further discussion regarding the Colstrip coal plants production O&M.

IX. COMPARISON OF PROJECTED POWER COSTS TO THE PROJECTED POWER COSTS IN THE 2009 GRC

Q. What are the principal differences between the power cost projections in this proceeding and the power cost projections approved in the 2009 GRC?

A. The power cost projection in this case, including production O&M and ratemaking adjustments, is approximately $88.2 million *lower* than the power costs projections approved in the 2009 GRC. Projected power costs decreased $114.9 million, production O&M costs increased $25.6 million and regulatory disallowances decreased $1.1 million (to zero), for a net decrease to rate year power costs of $88.2 million. Please see Exhibit No. ___(DEM-7C) for a comparison of the projected power costs and generation for the 2009 GRC rate year (April 2010 through March 2011) and the projected power costs for the rate year in this proceeding (May 2012 through April 2013).

Q. What are the causes of the change in projected power costs relative to the 2009 GRC?

A. The following items caused the majority of the change to projected rate year power costs from the 2009 GRC:

(i) lower rate year average gas prices and AURORA-derived rate year market power prices, as discussed above;

(ii) lower priced PSE short term power and gas for power contracts;

(iii) lower costs due to the expiration of the Tenaska, March Point 1 and 2 and North Western Energy contracts noted above which have been replaced with lower priced market power;

(iv) decreased Mid-C and owned hydro generation, 1.8 million MWhs (202 aMW), primarily due to the decrease in PSE's contractual share of the Chelan PUD projects, as discussed above;

(v) decreased Mid-C contract costs due to the new Chelan PUD contract are mitigated by the amortization of the $89 million capacity reservation charge under the same agreement and lower Reasonable Portion revenues under the Grant PUD contract, as discussed above;

(vi) increased Colstrip coal production costs due to increasing strip ratios (the amount of overburden that must be removed per ton of coal produced) and higher collective bargaining agreement rates, diesel fuel and explosives. Royalties and production taxes also increased direct costs. These are discussed in the Prefiled Direct Testimony of Mr. Mike Jones, Exhibit No. ___(MLJ-1CT);

(vii) decreased Colstrip generation due to a higher 4-year average forced outage rate and two planned major outages which overlap into the rate year as compared to a lower average forced outage and no major scheduled outages in the 2009 GRC power cost forecast, as discussed in the Prefiled Direct Testimony of Mr. Mike Jones, Exhibit No. ___(MLJ-1CT);

(viii) an addition of 21 average megawatts of forecast load from the 2009 GRC rate year;

(ix) increased fixed gas transportation costs associated with the agreements for additional capacity with Westcoast and Williams Northwest Pipeline for Station 2 and Stanfield sourced gas, as noted above;

(x) addition of the LSR Phase 1 wind facility, as discussed above, which adds 892,068 MWhs (102 aMW) of power generation and $10.7 million of power costs;

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

(xii) increased production O&M costs as discussed above.

X. COMPARISON OF ACTUAL TO PROJECTED POWER COSTS

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

A. As shown in the prefiled direct testimony of Salman Aladin, Exhibit No. ___(SA-1CT), over the first nine Power Cost Adjustment mechanism periods, July 1, 2002 through December 31, 2010, PSE's rates have under-recovered actual power costs by $64.0 million. PSE will recover only $13.4 million, or 21% of this under-recovery from customers.

Q. Please discuss why actual power costs differ from those set in rates.

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

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

(ii) weather uncertainty affecting power usage;

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

(iv) risk of forced generation outages;

(v) variability of wind generation; and

(vii) transmission and transportation constraints.

Although power costs set in rates are estimated "as closely as possible to costs that are reasonable expected to be actually incurred,[18]" they are still forecasts of future events, which are further limited by regulatory normalizing assumptions. Specifically, current ratemaking normalizes the power cost volatilities by employing:

(i) a 50-year hydro data set to determine hydro generation, which is requested to be changed to a 70-year set in this proceeding;

(ii) a weather normalized load forecast;

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

(iv) historical average forced outage rates; and

(v) forecast average wind generation.

Q. What are the differences between the power cost projections set in the 2009 GRC and the actual power costs for the 2009 rate year?

A. Actual power costs for the 2009 rate year (April 2010 through March 2011) were $4.1 million higher than those set in the 2009 GRC. However, there were three large, one-time items during this time period which increased power costs by $10.1 million:

(i) In June 2010, PSE lowered the carrying value of its

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

receivable from the California Independent System Operators by $17.8 million;

(ii) in November 2010, PSE received a $5.6 million refund from BPA due to a financial settlement related to the over-return of losses; and

(iii) in March 2011, PSE received a refund of $2.1 million from BPA in settlement of a Goldendale station service metering issue.

Without these one-time items, actual power costs for April 2010 through March 2011 were $5.9 million lower than those set in the 2009 GRC as shown in the Table 11 below.

Table 11. Power Cost Comparison to 2009 GRC
($ in millions)

	Apr. 2010 – May 2011
Actual Rate Year Power Costs	1,010.5
Less One-Time Items:	
California Receivables Write-off	17.8
BPA Losses Refund	(5.6)
BPA Goldendale Refund	(2.1)
Total One-Time Items	10.1
Actual Power Cost Excluding One-Time Items	1,000.5
Power Cost Excluding One-Time Items	1,000.5
2009 GRC Power Costs	1,006.4
Actual Power Costs Lower than 2009 GRC	(5.9)

The primary drivers of the lower power costs for the 2009 GRC rate year were a combination of:

(i) lower market prices plus slightly higher heat rates;

(ii) lower coal costs; and

(iii) lower Mid-C hydro contract costs.

These lower power costs were offset greatly by lower generation output from

PSE's share of the Mid-C projects and from PSE's wind resources.

In the 2009 GRC AURORA model, PSE was short a net amount of 1,338,911 MWhs (152 aMW) of power to meet the rate year demand. The 1,338,911 MWhs of power short was forecast to be purchased in the market at an average price above $45/MWh; however, due to the decline in power prices, the actual average cost of market purchases were lower than those set in rates. While the average price for market sales also declined, the impact was more than offset by the benefit of market purchases.

Table 12. Market Purchases and Sales Actuals Compared to 2009 GRC
2009 GRC Rate Year (April 2010 – March 2011)

	Market Purchases			Market Sales			Net Market Purchases & Sales		
	Actual[1]	**09GRC**	**Change**	**Actual[1]**	**09GRC**	**Change**	**Actual[1]**	**09GRC**	**Change**
$ in 000s	$107,710	$92,987	$14,723	($59,093)	($28,648)	($30,445)	$48,616	$64,339	($15,723)
MWh	4,017,140	2,057,825	1,959,315	(2,082,616)	(718,914)	(1,363,702)	1,934,524	1,338,911	595,613
$ / MWh	$26.81	$45.19	($18.37)	$28.37	$39.85	($11.47)	N/A	N/A	N/A

[1] Market Purchases and Sales exclude the power hedges that were included in the 2009 GRC.

In addition to the benefit resulting from market prices, Mid-C hydro contract costs were $6.4 million lower than the costs included in rates. This reduction in costs from the PUD budgeted amounts was primarily a result of two large true-ups related to the prior contract year. Both Douglas and Grant PUD bill PSE on a monthly basis based on a budgeted amount of spending and true-up to actuals at the end of the contract year.

Coal costs were also below the amount included in the 2009 GRC due to lower than budgeted fixed and variable Western Energy Company costs. Furthermore, coal generation was lower than expected due to low Mid-C market prices which made it more favorable to displace Colstrip units and replace the power with lower-priced market purchases.

The reduction in the 2009 GRC rate year power costs was offset by increases caused by 1) much lower Mid-C hydro generation due to 80.4 percent of normal[19] runoff at Grand Coulee; and 2) lower wind generation as shown in the table below. This "lost" generation was replaced with market purchases as can be seen in Table 12 above.

Table 13. Actual Generation Higher / (Lower) than 2009 GRC

	Mid-C Hydro[1]	Wind
Apr-10	(167,071)	42,570
May-10	(40,726)	(8,244)
Jun-10	13,860	(6,466)
Jul-10	(64,367)	(30,166)
Aug-10	(151,937)	(2,507)
Sep-10	(75,212)	(10,037)
Oct-10	(18,171)	(33,006)
Nov-10	43,975	(19,839)
Dec-10	(68,101)	(12,563)
Jan-11	(25,492)	(5,627)
Feb-11	112,504	4,601
Mar-11	103,365	(20.683)
Total	(337,374)	(101,967)

[1]Mid-C hydro shown is net of CEA

[19] During the period April - September 2010, runoff at Grand Coulee was 80.4 percent of normal where normal runoff is considered to be the 30 year average from 1971 to 2000.

Q. Why have you compared actual power costs to those set in rates in the 2009 GRC?

A. In the final order for the 2009 GRC, the Commission provided an expectation that PSE continue to examine and provide explanations of how well the estimation of net power costs compares with actual power costs.[20] The twelve month period April 2010 through March 2011 represents the rate year for which power costs were determined in the 2009 GRC and provides real-world examples of the volatilities that PSE works with around the clock to provide cost effective, reliable service to its customers.

XI. CONCLUSION

Q. Please summarize your testimony.

A. PSE actively manages the power and gas cost risks faced by its customers in order to keep power costs as low as reasonably possible. PSE's $992.5 million projected rate year power costs for this proceeding are consistent with, and based on, sound assumptions using methodologies approved by the Commission in PSE's prior general and power cost only rate cases.

Q. Does that conclude your prefiled direct testimony?

A. Yes, it does.

[20] *See* 2009 GRC Final Order at ¶ 173.