EXHIBIT NO. DEM-12CT
DOCKET NOS. UE-090704/UG-090705
2009 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-090704** **Docket No. UG-090705**

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

REDACTED
VERSION

DECEMBER 17, 2009

PUGET SOUND ENERGY, INC.

PREFILED REBUTTAL TESTIMONY (CONFIDENTIAL) OF DAVID E. MILLS

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Are you the same David E. Mills who provided in this proceeding prefiled direct testimony, Exhibit No. DEM-1CT, on May 8, 2009, and prefiled supplemental testimony, Exhibit No. DEM-9CT, on September 28, 2009, each on behalf of Puget Sound Energy, Inc. ("PSE")?

A. Yes.

Q. What is the purpose of this prefiled rebuttal testimony?

A. This rebuttal testimony responds to the joint testimony of Mr. Alan P. Buckley, witness for the Staff of the Washington Utilities and Transportation Commission ("Commission Staff") and Mr. Donald Schoenbeck, witness for the Industrial Customers of Northwest Utilities ("ICNU") (collectively referred to as the "Joint Parties"), Exhibit No. JT-1CT, and the testimony of Mr. Scott Norwood, witness for the Public Counsel section of the Washington State Attorney General's Office ("Public Counsel"), Exhibit No. SN-1HCT, with respect to various power cost adjustment proposals.

First, this prefiled rebuttal testimony provides a review of the AURORA model and its benefits in modeling projected rate year power costs. Use of the AURORA model is proper because it is consistent with prior PSE rate proceedings and is a model that has been proven to work in setting PSE's Baseline Rate.

Second, this rebuttal testimony addresses the following power cost adjustments proposed by the Joint Parties to which PSE can agree:

(i) an adjustment to correct projected generation from PSE's Upper Baker River Project and Lower Baker River Project;

(ii) an adjustment to update Mid-Columbia contract costs to reflect more recent budgets from the public utility districts that operate the hydroelectric projects; and

(iii) an adjustment to correct and include additional benefits associated with PSE's plan to acquire Westcoast pipeline capacity.

Third, this rebuttal testimony addresses the following power cost adjustments proposed by the Joint Parties to which PSE cannot agree:

(i) an adjustment to reduce costs associated with PSE's rate year natural gas for power hedges;

(ii) an adjustment to include benefits associated with the contract for Jackson Prairie gas storage facility capacity;

(iii) an adjustment to reduce regional loads;

(iv) an adjustment to include additional benefits associated with PSE's plan to acquire Westcoast pipeline capacity; and

(v) an adjustment to remove certain hydro years' generation.

Fourth, this rebuttal testimony rejects the following power cost adjustments proposed by Public Counsel:

(i) an adjustment to calculate projected rate year power costs using a more recent hydro period; and

(ii) an adjustment to reduce projected rate year power costs for additional off-system sales margins.

Fifth, this rebuttal testimony briefly responds to proposals of the Joint Parties and Public Counsel to change the regulatory recovery methodology associated with gas costs and gas for power mark to market costs.

Sixth, this rebuttal testimony presents an update of PSE's projected rate year power costs, based on (i) the power cost adjustments proposed by the Joint Parties to which PSE can agree and (ii) updated information.

Finally, this rebuttal testimony provides information to adjust projected rate year power costs for the Tenaska and March Point 2 regulatory disallowances.

II. THE AURORA MODEL AND RATES

Q. Please describe the AURORA model that PSE uses to project rate year power costs in this proceeding.

A. The AURORA model is a fundamentals-based model that employs a multi-area, transmission-constrained dispatch logic to simulate real market conditions, based upon supply and demand. The AURORA model captures the dynamics and economics of electricity markets—both short-term (hourly, daily, and monthly) and long-term—to imitate the functioning of wholesale power markets throughout the Western Electricity Coordinating Council ("WECC") region.

The AURORA model simulates, on an hourly basis, economic dispatch of the regional fleet of generating resources to meet regional electric loads, based on input fuel prices and other variable operating costs, inter-regional transmission limitations and other factors. A primary result from the AURORA model is a forecast of wholesale market prices for power that assumes (i) that market participants have perfect foresight and make economically rational decisions and (ii) that the market seeks and maintains continuous equilibrium. In addition to market-wide analysis, the AURORA model also has the capability to simulate hourly economic dispatch of a utility's generation resource portfolio.

Q. Please give a brief history of PSE's use of the AURORA model.

A. PSE began using the AURORA model in 1998 and has used the model in all subsequent Least Cost Plans ("LCPs") and Integrated Resource Plans ("IRPs"). PSE used the AURORA model in LCPs and IRPs to develop long-term power price projections under multiple scenarios of loads, gas prices, and environmental standards. PSE also used the AURORA model in LCPs and IRPs to project variable PSE resource portfolio costs.

PSE has used the long-term power prices from the AURORA model as the estimated avoided cost schedule for resource acquisitions. PSE has also used the AURORA model to analyze and support resource acquisition decisions for an interest in the Frederickson Generating Station, the Hopkins Ridge Wind Facility (and expansion), the Goldendale Generating Station, the Wild Horse Wind Facility (and expansion), the Sumas Generating Station, and the Mint Farm Generating Station.

PSE's electric rates have reflected projected rate year power costs modeled by the AURORA model since the 2001 general rate case (Docket Nos. UE-011570 & UG-011571). Each subsequent general rate filing and power cost only rate filing also used the Aurora model to project rate year power costs. In each of these proceedings, PSE ran the AURORA model and then combined the AURORA model variable power cost projection with costs not included in the AURORA model (the "Not In Models" information) regarding PSE's projected fixed power costs for the rate year in order to develop the projection of PSE's total power costs for the rate year. PSE used these power cost projections to set each proceeding's Baseline Rate, which was then used to calculate the over and under cost recoveries within the Power Cost Adjustment ("PCA") mechanism.

Q. Please describe some of the strengths of the AURORA model.

A. Strengths of the AURORA model include the following:

(1) The AURORA model is a comprehensive, integrated model of electric loads and generating resources in the entire WECC region and Western Interconnection;

(2) The AURORA model accounts for many of the fundamental supply and demand factors that determine power prices in thirteen sub-regions throughout Western North America;

(3) The AURORA model addresses price effects and other interactions between sub-regions (e.g., between California and the Pacific Northwest);

(4) The AURORA model is a standardized model that is widely used and understood by utilities, regulators, the Northwest Power and Conservation Council, Bonneville Power Administration, and others; and

(5) The AURORA model simulates economic dispatch of each generating resource on an hour-by-hour basis.

Q. Does the AURORA model have any characteristics that affect its usefulness?

A. Yes. First, the AURORA model is a detailed, complicated model, with thousands of lines of data that produces large output data sets that can make it time-consuming to evaluate and review. Second, the AURORA model does not have sophisticated capabilities to model fixed costs, which is why PSE has to add in costs outside of the AURORA model via the "Not in Models" workbook. Finally, these characteristics of the AURORA model make it difficult to compare total (fixed and variable) costs for different resource portfolio strategies.

Q. Are the power costs produced by the AURORA model an accurate forecast of the variable rate year power costs?

A. No model, of course, will forecast actual power costs with complete accuracy. In addition, certain normalizing assumptions that PSE is required to make—such as use of the Commission-approved 50-year hydro data set, a weather normalized load forecast, and a static three-month average forward gas price forecast—increase the likelihood that actual rate year power costs will differ from the power costs projected by the AURORA model. Even with such constraints, however, the AURORA model, over time, has

(i) produced a valid and reasonable forecast of how PSE would operate its resources to serve its rate year load and

(ii) provided the variable operating costs for PSE's generating resource by dispatching gas-fired units when their generation cost is less than the market price and simulates hourly market sales or purchases to balance loads and resources.

Q. How has the Baseline Rate, which relies on rate year power costs projections of the AURORA model, compared to actual rate year power costs over time?

A. Over the first seven PCA periods, beginning July 1, 2001, and ending December 31, 2008, PSE's power costs have tracked very closely to the respective allowed power costs. In fact, as shown in Table 1 below, power cost under-recoveries have been $6.8 million (or 0.1% of the allowed power costs).

Table 1

	Puget Sound Energy, Inc.						
	Power Cost Adjustment Mechanism History						
	($$ in Millions)						
	Period	**PCA Period**	**Actual Allowed Costs**	**Actual Recoveries**	**(Over)/ Under Recovery**	**Company Share**	**Customer Share**
	7/02-6/03	1	$ 845.4	$ 843.1	$ 2.3	$ 2.3	$ -
	7/03-6/04	2	$ 903.0	$ 872.8	$ 30.2	$ 25.1	$ 5.1
	7/04-6/05	3	$ 959.7	$ 949.4	$ 10.3	$ 10.3	$ -
	7/05-6/06	4	$ 1,064.7	$ 1,075.2	$ (10.5)	$ (10.5)	$ 0.0
	7/06-12/06	5	$ 597.0	$ 597.1	$ (0.1)	$ (0.1)	$ -
	1/07-12/07	6	$ 1,226.5	$ 1,253.1	$ (26.6)	$ (23.3)	$ (3.3)
	1/08-12/08	7	$ 1,331.1	$ 1,329.9	$ 1.2	$ 1.2	$ -
Cumulative thru PCA 7			$ 6,927.4	$ 6,920.6	$ 6.8	$ 5.0	$ 1.8
(11 mo actual)	1/09-11/09	YTD 8	$ 1,242.6	$ 1,225.0	$ 17.5	$ 17.5	$ -
Cum (Over)/Under Recovery			$ 8,170.0	$ 8,145.7	$ 24.3	$ 22.5	$ 1.8
% of Under Recovery thru PCA7					0.1%		

As expected, some years have under-recoveries and some years have over-recoveries. Over the history of the PCA mechanism, however, PSE's actual power costs have been close to the respective Baseline Rates, which rely on rate year power costs projections of the AURORA model.

Through November 2009, PSE's actual power cost under-recoveries in the current PCA 8 period are $17.5 million due in large part to poor hydro conditions and an unplanned outage at Colstrip Unit 4. PSE expects that total PCA 8 under-recoveries will exceed this $17.5 million amount because December power cost under-recoveries have averaged around $6 million.

Q. Does PSE use the AURORA model for portfolio risk management and day-to-day portfolio management purposes?

A No. PSE does not use the AURORA model for portfolio risk management and day-to-day portfolio management purposes. Consequently, PSE does not use AURORA's dispatch modeling of PSE's owned gas fired units to determine the hedging of power or natural gas used for power generation.

Q. Why doesn't PSE use the AURORA model for portfolio risk management and day-to-day portfolio management purposes?

A. As described above, the AURORA model, is an effective production cost model that predicts future period power costs using a number of static assumptions including natural gas prices, loads, hydro conditions, and generation unit availability. The AURORA model, however, is not a rigorous risk management model designed to be updated on a daily basis and run regularly for portfolio management and hedging. For example, AURORA does not create a set of input data scenarios incorporating correlated gas and power prices based on historical prices, power usage based on weather uncertainty, and daily hydroelectric plant dispatch based on power prices. AURORA is not designed to capture and incorporate PSE's daily hedging and trading activity nor does it include natural gas portfolio modeling capabilities.

Q. What model does PSE use for risk management purposes?

A. For day-to-day active management of the power portfolio, PSE uses a probabilistic modeling risk system that PSE runs several times weekly, using updated operational and market intelligence that includes regularly updated prices of power, natural gas, and market heat rates. PSE uses the results of this portfolio risk system to determine, on a forward-looking basis, the updated commodity risk exposure for PSE and its customers. PSE's approved hedging strategies then dictate the timing and quantity of hedging (gas or power) given these results.

Q. What is PSE's recommendation regarding the AURORA model?

A. As I will discuss below, the Joint Parties propose to use the AURORA model in a manner it was not meant to be used to determine the recovery levels for gas for power fixed contracts. Public Counsel proposes to not use AURORA as it was intended to be used to determine the rate year market sales volumes and costs. PSE recommends the continuation of use and reliance on the AURORA model in this proceeding, without adjustment, as it has been in the many proceedings and for the many purposes referred to above.

III. UNCONTESTED POWER COST ADJUSTMENTS

Q. Does PSE agree with any power cost adjustments proposed by the Joint Parties?

A. Yes. PSE agrees with several of the power cost adjustments proposed by the Joint Parties. These uncontested power cost adjustments reduce PSE's projected rate year power costs by $9.7 million, as demonstrated in Table 2 below.

Table 2

Uncontested Joint Party Power Cost Adjustments ($ in Millions)		
Upper/Lower Baker generation correction	$	(1.8)
MidC Budget Updates - Chelan PUD		(1.4)
MidC Budget Updates - Grant PUD		(0.8)
Westcoast Pipeline Benefit correction		(5.8)
Uncontested Joint Parties Adjustments	$	(9.7)

A. Power Cost Adjustment Related to the Upper Baker River Project and the Lower Baker River Project

Q. Please describe the power cost adjustment proposed by the Joint Parties with respect to the Upper Baker River Project and the Lower Baker River Project.

A. During the course of this proceeding, PSE discovered that it had inadvertently used the wrong time period in determining the projected rate year generation for the Upper Baker River Project and the Lower Baker River Project. Use of the correct data set increases projected rate year hydro generation by 34,661 MWhs, and decreases AURORA modeled projected rate year power costs by $1.8 million. The Joint Parties propose an adjustment to correct for this inadvertent error. *See* Exhibit No. JT-1CT at page 4, lines 8-17. PSE agrees with this adjustment.

B. Mid-Columbia Contract Costs

Q. Please describe the power cost adjustment proposed by the Joint Parties with respect to the Mid-Columbia projects.

A. PSE has several contracts for the purchase of output from certain Mid-Columbia ("Mid-C") hydroelectric projects. Specifically, PSE has contracts with the following public utility districts for the purchase of output from the following projects:

(i) contracts with Public Utility District No. 1 of Chelan County, Washington ("Chelan PUD") for the purchase of output from the Rocky Reach Project and the Rock Island Project;

(ii) contracts with Public Utility District No. 2 of Grant County, Washington ("Grant PUD") for the purchase of output from the Wanapum Project and the Priest Rapids Project; and

(iii) contracts with Public Utility District No. 1 of Douglas County, Washington ("Douglas PUD") for the purchase of output from the Wells Project.

PSE's contracts provide that it pay its contracted portion of the operations and debt expenses of the respective hydroelectric projects in return for a specified portion of the outputs of the projects. Projected rate year power costs represent the most recent budget or forecast information from these public utility districts. PSE has traditionally updated these costs in determining final projected rate year power costs. PSE proposes to include an additional $1.4 million in projected rate year power costs to reflect updated information for the Mid-C contracts, as discussed below.

1. <u>Updated Projected Rate Year Power Costs Associated with the Rock Island Project and the Rocky Reach Project</u>

Q. What is the projected rate year power cost change related to the Rock Island Project and the Rocky Reach Project?

A. Chelan PUD has provided updated preliminary budgets during the course of this proceeding for the Rock Island Project and the Rocky Reach Project. These preliminary budgets, although not final, represent the best estimate of the costs associated with PSE's portion of the projected rate year costs for the Rock Island Project and the Rocky Reach Project and decrease rate year power costs by $1.4 million from the projected rate year power costs provided in PSE's supplemental filing dated September 28, 2009. The Joint Parties have reflected the budgets associated with the projects identified above in a recommended power cost adjustment. *See* Exhibit No. JT-1CT at page 13, line 11, through page 14, line 6. PSE agrees with this adjustment.

2. <u>Updated Projected Rate Year Power Costs Associated with the Priest Rapids Project and the Wanapum Project</u>

Q. What is the projected rate year power cost change related to the Priest Rapids Project and the Wanapum Project?

A. Grant PUD has provided updated preliminary budgets during the course of this proceeding for the Priest Rapids Project and the Wanapum Project. These preliminary budgets, although not final, represent the best estimate of the costs associated with PSE's portion of the projected rate year costs for the Priest Rapids

Project and the Wanapum Project and decrease rate year power costs by $0.8 million. The Joint Parties have reflected the budgets associated with the projects identified above in a recommended power cost adjustment. *See* Exhibit No. JT-1CT at page 13, line 11, through page 14, line 6. PSE agrees with this adjustment.

Q. Is there additional updated information related to the Priest Rapids Project that are not reflected in the power cost adjustments proposed by the Joint Parties?

A. Yes. There is more recent information regarding the Priest Rapids Project that is not reflected in the power cost adjustments proposed by the Joint Parties. As indicated in PSE's First Supplemental Response to ICNU Data Request No. 03.11, provided as Exhibit No. JT-5, PSE noted that Grant PUD would provide updated cost information after Grant PUD had conducted a power auction on November 5, 2009. PSE's Second Supplemental Response to ICNU Data Request No. 03.11, provided as Exhibit No. DEM-13C, noted the power auction's 2010 price was lower than forecast, so the Reasonable Portion Revenues were decreased, which causes an increase of $3.5 million to PSE's projected rate year power costs.

The Joint Parties did not have an opportunity to include this updated cost information in their response filing. Therefore, this updated cost information is neither contested nor uncontested. PSE has subsequently discussed this update with the Joint Parties, and it is PSE's understanding that the Joint Parties do not oppose the reflection of the impact of the final auction in PSE's rate year power costs.

Q. What is the total change to PSE's projected rate year power costs associated with output from the Priest Rapids Project and the Wanapum Project?

A. Considering both the updated preliminary budgets and the results of the auction, PSE's projected rate year power costs associated with the Priest Rapids Project and the Wanapum Project increase $2.7 million from the projected rate year power costs provided in PSE's supplemental filing dated September 28, 2009.

C. <u>Westcoast Pipeline Benefit</u>

Q. Please describe the power cost adjustment proposed by the Joint Parties with respect to the Westcoast Pipeline benefit.

A. PSE's projected rate year power costs include $8.3 million of costs associated with Westcoast Pipeline firm capacity acquired to source gas from Canada's Station 2 hub. Consistent with prior rate proceedings for similar gas capacity, PSE included a benefit for the difference between the costs of sourcing the gas from the Station 2 hub versus the Sumas hub (known as the "basis differential") for the months in which the forecast gas price at the Station 2 hub (considering the 2% pipeline loss) was lower than that at the Sumas hub. The calculation of the benefit included in the projected rate year power costs provided in PSE's supplemental filing dated September 28, 2009, was erroneous because it did not multiply the daily benefit by the days in the month. The Joint Parties have reduced projected rate year power costs by $5.7 million to correct for this error. *See* Exhibit No. JT-1CT at page 15, line 20, through page 16, line 7. PSE agrees with this adjustment.

Q. Does PSE agree with the power cost adjustment proposed by the Joint Parties that would use a historical basis gain differential to derive Station 2 hub prices from the Sumas hub forward prices?

A. No. For the reasons discussed further below, PSE does not agree with the power cost adjustment proposed by the Joint Parties that would use a historical basis gain differential to derive Station 2 hub prices from the Sumas hub forward prices.

IV. CONTESTED POWER COST ADJUSTMENTS

A. Contested Power Cost Adjustments Proposed by the Joint Parties

1. Gas for Power Mark to Market

Q. What is the mark-to-market adjustment for natural gas hedges?

A. The mark-to-market adjustment for natural gas hedges is a calculation included in the Not In Models rate year costs and outside the AURORA model. The adjustment requires calculating the difference between the three-month average monthly cost of natural gas at the pricing cut-off date (August 13, 2009 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.

Q. What adjustment do the Joint Parties propose regarding the mark-to-market for natural gas hedges?

A. The Joint Parties propose to impose an arbitrary cap on the monthly volume of the rate year gas for power hedges. The Joint Parties propose to remove the monthly volume of gas hedges—priced at the monthly average mark-to-market cost for all natural gas hedges—that exceed 80% of the monthly gas requirements calculated using the AURORA model gas fired generation (the "removed hedges"). The Joint Parties suggest that this power cost adjustment would reduce the projected rate year power costs provided in PSE's supplemental filing power dated September 28, 2009, costs by $11.8 million. *See* Exhibit JT-1CT at page 22, line 9, through page 23, line 7.

Q. Is the mark-to-market adjustment for natural gas hedges recommended by the Joint Parties reasonable?

A. No. The mark-to-market adjustment for natural gas hedges recommended by the Joint Parties is unreasonable because the 80% cap level is an arbitrary one, and the AURORA model generation need, on which the cap is placed, is not used for PSE's actual hedging activity. Although the Joint Parties do not challenge PSE's hedging program, they propose that the resulting costs associated with these measures do not warrant full recovery in rates.

Q. Does PSE use the AURORA model base load gas-fired generation need for hedging purposes?

A No. As discussed above, PSE does not use the AURORA model for portfolio risk management and day-to-day portfolio management purposes. Therefore, PSE does not utilize the AURORA modeled dispatch of PSE's owned generating units to determine the hedging of natural gas used for power generation.

PSE has been clear that, for day-to-day active management of the power portfolio, PSE uses a probabilistic modeling risk system that is run several times weekly, using updated operational and market intelligence that includes regularly updated prices of power, natural gas, and market heat rates. The Joint Parties remain indifferent to PSE's hedging policy but seek to deny recovery of the costs of such policy because such costs happen to be increasing for this particular rate year.

Q. Why is the amount of hedging higher in PSE's portfolio model?

A. The amount of hedging for the physical gas demand is higher in PSE's portfolio model because the rate year market heat rates at August 13, 2009 are higher than the AURORA-derived market heat rates using a three-month average gas price at

August 13, 2009. All of PSE's gas for power hedges pertaining to the rate year and transacted at August 13, 2009 should be allowed full recovery in setting Baseline Rates.

Q. Have PSE's customers generally benefited from the existing treatment of mark-to-market for gas hedges?

A. Yes. PSE's customers have generally *benefited* from the existing treatment of mark-to-market for gas hedges. PSE's rates have included a mark-to-market benefit (a reduction to power costs) associated with its rate year fixed-price gas for power contracts since the 2003 power cost only rate case. As shown in Table 3 below, PSE's customers have benefited from gas for power hedging by over $122 million.

Table 3

Rate Case	Docket	3 mo. Average Prices Ending	Rate Year Beginning	Gas Contract MTM (Gain) / Loss ($ in Millions) Short-term Contracts	Long-term Contracts	Total	Months in Rates	Estimated Customer Benefit
2003 PCORC	UE-031725	9/27/2003	4/1/2004	($0.0)	($13.6)	($13.6)	11	$ (12.5)
2004 GRC	UE-040640	9/30/2004	3/1/2005	($0.0)	($22.8)	($22.9)	9	$ (17.1)
2005 PCORC	UE-050870	4/29/2005	12/1/2005	($1.0)	($28.3)	($29.3)	7	$ (17.1)
2005 PCORC Update	UE-060783	4/28/2006	7/1/2006 [1]	$0.5	($16.0)	($15.5)	6	$ (15.5)
2006 GRC	UE-06266	11/30/2006	1/1/2007	$4.3	($33.8)	($29.5)	8	$ (19.7)
2007 PCORC	UE-070565	5/10/2007	9/1/2007	$1.9	($30.1)	($28.2)	14	$ (32.9)
2007 GRC	UE-072300	3/11/2008	11/1/2008	($5.2)	$0.0	($5.2)	17	$ (7.3)
				$ 0.5	$ (144.7)	$ (144.2)		$ (122.1) Credit = Customer Benefit

1 The 2005 PCORC Update included power cost updates for the 6-month period beginning July 1, 2006.

In other words, customer rates would have been higher over the past several years if rates were set using only forward gas prices.

Q. Has PSE significantly modified its energy commodity hedging strategies since its last general rate proceeding?

A. No. PSE has not significantly modified its energy commodity hedging strategies since its last general rate proceeding. In addition, this strategy and the resulting hedges have been explained in detail in PSE's prior PCA compliance filings.

The framework of PSE's hedging strategies has not been significantly altered since 2003. Please see Exhibit No. DEM-3C for a detailed overview of PSE's hedging strategies. In 2007, following the run up in natural gas prices to near-record levels in 2005, PSE extended the term or tenor of its hedging program to remove additional volatility from commodity prices faced by PSE and its customers. PSE based its decision to extend the term of its hedging strategies upon a thorough review of industry best practices and market research. PSE, working with Commission Staff, developed and implemented market research survey instruments that resulted in focus group discussions with a wide variety of customers and completion of an in-depth customer survey. Through this analysis, PSE learned that a majority of its customers prefer less volatility and more stability in their energy costs. The logical result of these findings was to extend the term of PSE's existing hedging strategies.

Q. Please describe PSE's concerns with the proposal of the Joint Parties to use an 80 percent cap on natural gas purchases based on the AURORA model?

A. In proposing to exclude costs associated with rate year gas for power transactions that are above 80% of the AURORA model gas requirements from the Baseline Rate, the Joint Parties are in effect proposing that PSE use static model results to set an arbitrary 80 percent cap on the amount of natural gas to hedge for power generation. Recognition of the static versus dynamic differences resulting from these two models raises an interesting counterpoint on how the Joint Parties proposal would function in a rapidly rising natural gas price or market heat rate environment. It is plausible that PSE, under the Joint Parties proposal, could find itself significantly short of natural gas in a rising price or heat rate environment because PSE was limited by an 80 percent cap based on a dated and static AURORA output that is not used by PSE to track actual market trends or changes in the power portfolio position.

Q. Please summarize PSE's conclusions regarding the mark-to-market for gas hedges adjustment proposed by the Joint Parties.

A. The proposal of an adjustment to mark-to-market costs based upon an arbitrary 80 percent volume from a static AURORA output exposes PSE and its customers to increased risk by the implication that PSE should hedge accordingly. Furthermore, this proposal undermines the intent and objectives of PSE's long-standing energy commodity hedging strategies. Historically, the existing treatment for gas hedges has resulted in a cumulative benefit to customers.

The timing of such a proposal appears to be solely motivated by a desire to capitalize on current lower natural gas prices when, in fact, there was no such proposal from either of the Joint Parties when the mark-to-market on gas for power transactions resulted in *savings* that were passed onto customers through lower Baseline Rates. PSE urges the Commission reject the mark-to-market for gas hedges adjustment proposed by the Joint Parties.

Q. Does PSE have any other issues with the mark-to-market for gas hedges adjustment proposed by the Joint Parties?

A. Yes. First, if the Commission were to adopt the arbitrary mark-to-market for gas hedges adjustment proposed by the Joint Parties, then PSE would have to be allowed to include up to 100% of the AURORA gas requirements in the rate year power costs.

Second, the Joint Parties' calculation prices the entire volume of the "removed hedges" at the Sumas hub even during months in which the volume of the removed hedges is greater than the volume hedged financially at the Sumas hub. The volumes of the "removed hedges" greater than the volume hedged at the Sumas hub should be calculated using the Rockies prices.

Finally, the Joint Parties' adjustment uses the average cost of all hedges, which includes the costs of hedges removed by Joint Parties. Because the Joint Parties suggest that PSE stop hedging at the 80% of AURORA gas need, their logic implies the hedges transacted subsequently should be the ones disallowed.

All of these adjustments are unnecessary and would surely be contentious in any future filing. Adding this additional burden to a model that is not designed for day-to-day operations to meet the service and reliability requirements of a utility is unreasonable.

2. <u>Jackson Prairie Storage Capacity</u>

Q. Please describe the Cabot asset management agreement.

A. As discussed in the direct prefiled testimony of R. Clay Riding, Exhibit No. RCR-1T, PSE took a three-year assignment of a small Jackson Prairie storage resource through an asset management arrangement with Cabot Oil & Gas Marketing Corporation ("<u>Cabot</u>") that will reside in the power book, involving 6,704 MMBtu per day of deliverability and 140,622 MMBtu of storage capacity. This assignment has an initial term of three years but continues year-to-year thereafter, subject to timely termination notice by either party. This assignment provides the power portfolio with access to natural gas storage, which is instrumental for intraday balancing of load, integration of renewable resources, and meeting peak-day load requirements with gas-fired generation resources.

Q. What value does the PSE electric portfolio retain with the Cabot asset management agreement?

A. First and foremost, access to natural gas storage is essential to increase electric service reliability and to ensure efficient integration of renewable resources. PSE's combustion turbine fleet is a critical component in meeting PSE's electric load requirements as well as providing day-to-day operational flexibility for unplanned generation outages, balancing load, and managing PSE's intermittent renewable generation resources.

Frequently, PSE's gas-fired combustion turbines are called upon to dispatch intra-day or on weekends to manage sudden, unexpected changes in load or wind generation. A liquid, intraday natural gas market, however, does not exist. If natural gas is available during these events, it usually comes at a premium to the standard daily product that is traded. It can be purchased and scheduled only during the two standard intraday scheduling cycles. If gas cannot be purchased during these windows, and PSE elects to run its generation units, it will have to draft the interstate pipeline or local distribution systems and subject itself to potential imbalance penalties.

Conversely, if a combustion turbine is displaced or output is reduced on the weekends or intraday, it is difficult to find a market to sell the gas. In these circumstances, the gas is sold at a discounted daily market price or PSE has to leave the gas on the interstate pipeline or local distribution systems, which packs the pipeline with excess gas and is subject to potential imbalance penalties.

PSE expects to rely more and more on its combustion turbines to meet the intra-hour generation variability from wind generation. There currently is no intra-hour energy market to procure products that would help support wind integration and load following needs. If PSE does not have the generating resources or the market options to meet these requirements, it significantly reduces PSE's ability to operate its electric system in a safe, reliable, and cost-effective manner. Therefore, having natural gas storage gives the power book the ability, on a real time basis, to withdraw gas from storage to dispatch its generators or inject excess gas into storage when units are displaced. This contributes to the overall reliability of the electric system.

Q. What is the power cost adjustment proposed by the Joint Parties with respect to the Cabot asset management agreement?

A. The Joint Parties note that the rate year should include some value associated with the Cabot asset management agreement to offset the costs of the storage for the power book. Accordingly, the Joint Parties calculate a seasonal difference between the average forward prices for the summer (May/June) and winter months (December/January) and multiply this by the storage volume of the agreement to reduce rate year power costs by $338,000. See Exhibit No. JT-1CT at page 24, line 13, through page 25, line 10.

Q. Does PSE agree with this proposed power cost adjustment?

A. No. If PSE could use this gas storage to capitalize solely on the seasonal price differentials, the adjustment proposed by the Joint Parties would seem appropriate. However, PSE does not have the opportunity to purchase the gas at low summer prices and store the gas to sell during the higher priced winter months because, as discussed above, PSE acquired the Cabot asset management agreement storage for reliability and renewable resource integration management.

PSE's rate year power costs, accordingly, should not include any benefit for the seasonal gas price differences.

3. <u>Regional Load Adjustment</u>

Q. Please describe the load adjustment filed by PSE in its supplemental filing dated September 28, 2009?

A. In its supplemental filing dated September 28, 2009, PSE reduced the forecasted rate year loads included in the AURORA model by 932,382 MWhs, or about 106 aMWs. This reduction reduced PSE's projected rate year power costs by $41.7 million. Please see Exhibit No. DEM-9CT at page 4.

Q. Did PSE reduce regional loads by the same amount?

A. No. PSE did not reduce regional loads in the AURORA model. PSE believes that its load reduction would have only a minor impact on the Pacific Northwest aggregate loads because the Pacific Northwest rate year load is about 163,229,598 MWhs, or 18,634 aMWs. Therefore, the reduction in PSE's load is less than 1 percent, or only about 0.57%, of the aggregate regional load. A subsequent run of the AURORA model proved the impact of incorporating the regional load reduction in the AURORA analyses is a reduction of about $0.12 million in projected rate year power costs.

Q. Why did PSE not incorporate regional load reductions in its supplemental filing dated September 28, 2009 to reflect the economic and demographic trends in the region?

A. As noted by the Joint Parties, there are thirty individual areas encompassing all or parts of eleven states, two Canadian provinces, and the northern portions of Baja California, Mexico included within the WECC region modeled in the AURORA database used in this rate filing. PSE did not have updated load forecasts or the economic trend data required to provide accurate adjustments to all WECC loads.

Q. Have the Joint Parties developed an adjustment to regional loads?

A. Yes. The Joint Parties reduced the AURORA model's regional loads in the Pacific Northwest, the load of Southern California Edison, and the load of Pacific Gas and Electric Company by assuming no load growth for 2009, 2010, and 2011 in the AURORA input database. This caused a $1.1 million reduction in the Joint Parties' forecast of PSE's rate year power costs. Exhibit No. JT-1CT at page 7, lines 13-21.

Q. Does PSE agree with the regional load adjustment in the AURORA model proposed by the Joint Parties?

A. No. PSE does not agree with the regional load adjustment in the AURORA model proposed by the Joint Parties. Neither PSE nor the Joint Parties have developed a methodology to analyze the extent of such an impact on regional loads. Although PSE does not agree with the ad hoc methodology used by the Joint Parties in deriving their proposed regional load reduction, PSE agrees that the same economic trend data that reduced PSE's load forecast may have an impact on the regional load forecast. Therefore, PSE proposes to adopt the $1.1 million reduction of rate year power costs proposed by the Joint Parties. This reduction, however, should be a one-time "Not In Model" power cost adjustment and not an adjustment in the AURORA model.

4. <u>Westcoast Pipeline Basis Benefit</u>

Q. Please provide a brief overview of the Westcoast pipeline benefit.

A. PSE has acquired Westcoast Energy T-South capacity in order to improve the reliability and predictability of supply to its generation portfolio, by diversifying supply risks. British Columbia originated supply can be moved to markets at Sumas (via Westcoast Energy T-South); markets in the US Midwest (via Alliance Pipeline); or to markets in Alberta and east (via Westcoast's interconnect with TransCanada's Alberta System). Currently only 72% of Westcoast Energy's T-South capacity of approximately 1,750 MDth/day to the Northwest Pipeline interconnect is contracted. Of this, approximately 67% or 850 MDth/day is held by load serving utilities (including PSE) or industrial end-users. The remaining 33% or 420 MDth/day is held by producers and marketers. During high demand periods, the 485 MDth/day of unsold capacity is often times fully utilized to serve demand at Sumas, including southern British Columbia. It can be reasonably assumed that firm capacity held by utilities and end-users is committed to serving firm customer requirements, and thus not available for purchase to serve PSE's generation requirements. It can also be reasonably assumed that firm capacity held by producers and marketers is dedicated, at least in large part, to longer-term firm gas supply sales agreements at Sumas. If the gas supply at Sumas that is backed by firm T-South pipeline capacity is generally not available to be acquired by PSE on a seasonal or short-term basis, PSE must then rely on gas supply that is not necessarily dedicated to the Sumas market. PSE is committed to assuring that sufficient supply be available at Sumas in high demand periods, which means that some supply needs to be obtained at Station 2, before it can be redirected to other markets.

Additional natural gas transportation was acquired by PSE as a means to diversify supply risks associated with PSE's gas supply requirements originating in British Columbia. As referenced in the Prefiled Rebuttal Testimony of Mr. Clay Riding, Exhibit No. RCR-5T, there has been a large volume of firm capacity from the Station 2 hub to the Sumas hub that has been returned to Westcoast Energy. As a result of the decrease in firm capacity holders, PSE is concerned with the risk associated with relying too heavily upon the Sumas hub for firm supplies because there has been a significant volume of gas at the Sumas hub that appears to be relying on non-firm or interruptible transportation service.

When setting rates, PSE bases projected rate year gas prices on a forecast of what is expected to occur in the rate year, as represented by a three-month average forward gas price forecast. In this instance, the gas is sourced at the Station 2 hub, which does not have a reliable forward price curve. Therefore, to determine the forecast gas price at the Station 2 hub for the supplemental filing dated September 28, 2009, PSE obtained a broker quote of the basis differential between the Station 2 hub and the Sumas hub.

Q. What is the power cost adjustment proposed by the Joint Parties with respect to the Westcoast pipeline basis benefit?

A. As discussed above, the Joint Parties have proposed a power cost adjustment with respect to the Westcoast pipeline basis benefit that corrected an erroneous calculation that failed to multiply the daily benefit by the days in the month. *See* Exhibit No. JT-1CT at page 15, line 20, through page 16, line 7. PSE agrees with this adjustment.

The Joint Parties have also proposed an unprecedented methodology that would use historical prices to determine the rate year benefit of the Westcoast pipeline acquisition. The Joint Parties use the actual basis differential between the two hubs (Station 2 hub versus Sumas hub) from calendar 2008 as a proxy for the rate year basis differential and propose an additional $3.9 million power cost reduction for a total benefit of nearly $10.0 million, or $1.7 million *more* than the cost of the pipeline capacity. *See* Exhibit No. JT-1CT at page 16, line 9, through page 19, line 11.

Q. What adjustment, if any, does PSE propose with respect to the Westcoast pipeline basis benefit?

A. The Joint Parties noted that a single quote did not provide enough information. Therefore, PSE has subsequently obtained four additional broker quotes of the basis differential between the Station 2 hub and the Sumas hub for the rate year. Although PSE has not transacted to firm any of the gas from the Station 2 hub to the Sumas hub, there are no instances where the basis gain is more than the cost of the pipeline capacity based on the additional broker quotes obtained. PSE, however, is willing to accept the risk that some pricing benefits will offset costs.

PSE proposes that the rate year power costs associated with the Westcoast pipeline be offset 100% with a forecast benefit of the basis differential between the Station 2 hub and the Sumas hub. Therefore, PSE proposes to reject the $3.9 million reduction in rate year power costs proposed by the Joint Parties and replace it with a reduction in rate year power costs of $2.4 million.

5. <u>Hydro Filtering</u>

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

A. During an average streamflow year, nearly thirty percent of PSE's electric energy production is from hydroelectric resources. These resources include both PSE's contractual rights under its Mid-C contracts and its owned hydroelectric projects: the Snoqualmie Falls Project, the Upper Baker Project, the Lower Baker Project, and the Electron Project. PSE interacts in a marketplace where it is normal for market prices to be low when hydro energy is abundant and market prices to be disproportionately higher when hydro conditions are poor. This creates a skewed distribution of power costs across various hydro conditions.

To consider the power cost impact from this volatile, yet highly valued resource, PSE uses fifty years of historical streamflow data to model hydroelectric generation as the determinant of an average water year. The fifty years of hydro generation is input into the AURORA model. The AURORA model relies on factors such as supply resources and regional 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 fifty model results—one for each of the fifty hydro years. The average of these fifty AURORA model runs is the AURORA model normalized power costs and generation for the rate year.

Q. Please explain the water filtering adjustment proposed by the Joint Parties.

A. The Joint Parties propose to remove power costs associated with Mid-C hydro generation that is beyond one standard deviation (defined by the Joint Parties as "outlier water years") from the average of the Mid-C fifty hydro years' generation to leave "the review and recovery of costs associated with those years, if indeed they do occur, to the annual PCA review when all costs are known". Exhibit No. JT-1CT at page 8, lines 4-5, and at page 12, line 1. Doing so reduces projected rate year power costs. The Joint Parties claim that this adjustment benefits "ratepayers by more appropriately realigning risk sharing" and better aligns "the methodology for determining base power supply costs with a regulatory environment that includes an annual PCA." Exhibit No. JT-1CT at page 12, lines 16-17, and at page 7, lines 26-27, respectively. The Joint Parties note this proposal is warranted only because PSE has a PCA mechanism in place. *See* Exhibit No. JT-1CT at page 8, line 18, and through page 9, line 4.

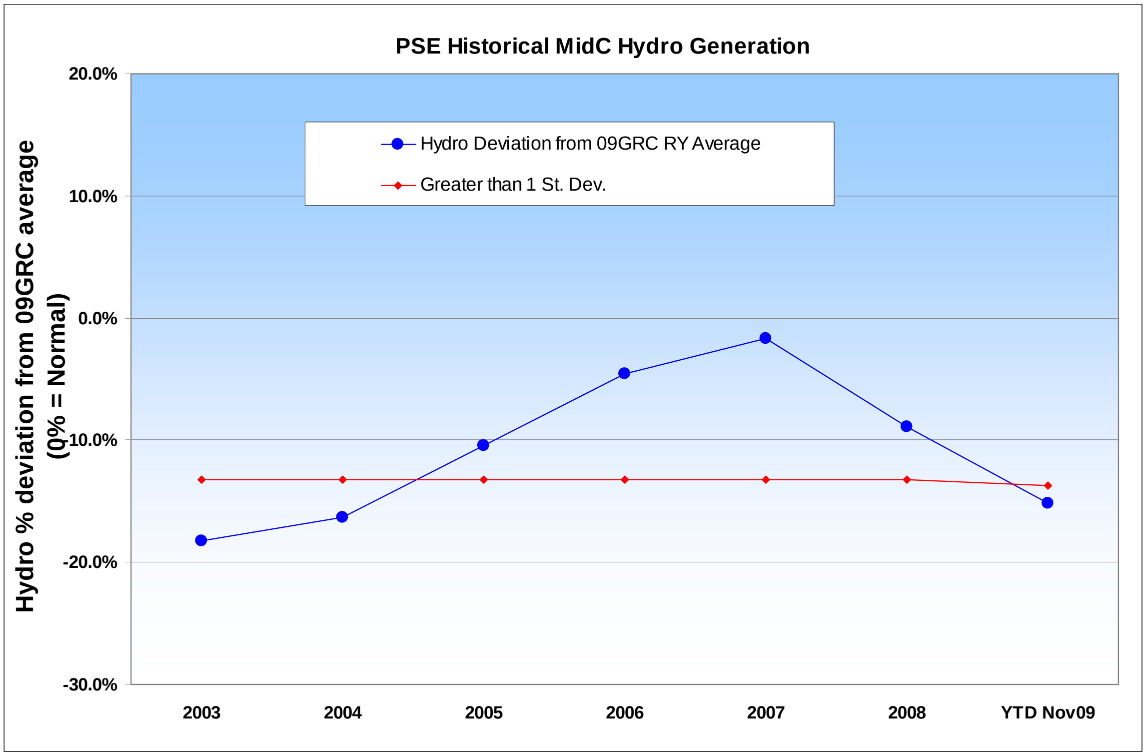
Q. Does PSE agree with the water filtering adjustment proposed by the Joint Parties?

A. No. In theory, rate year power costs should be calculated using agreed upon methodologies and regulatory precedents. The existence of a PCA mechanism is irrelevant when setting base rates. If a PCA mechanism is in place and if the PCA mechanism indeed shifts risk from the shareholders to customers, it is the underlying conditions of the PCA mechanism itself (i.e., sharing bands and procedures) that should be adjusted to more appropriately balance risk between shareholders and customers—not the underlying power costs. The proposal of the Joint Parties merely biases projected rate year power costs.

Q. Over the history of the PCA mechanism, has PSE experienced "outlier water years"?

A. Yes. In fact, three of the last seven years would be considered to be "outlier water years" as PSE's actual ownership share of Mid-C generation falls outside of one standard deviation as defined by the Joint Parties and shown in Table 4 below.

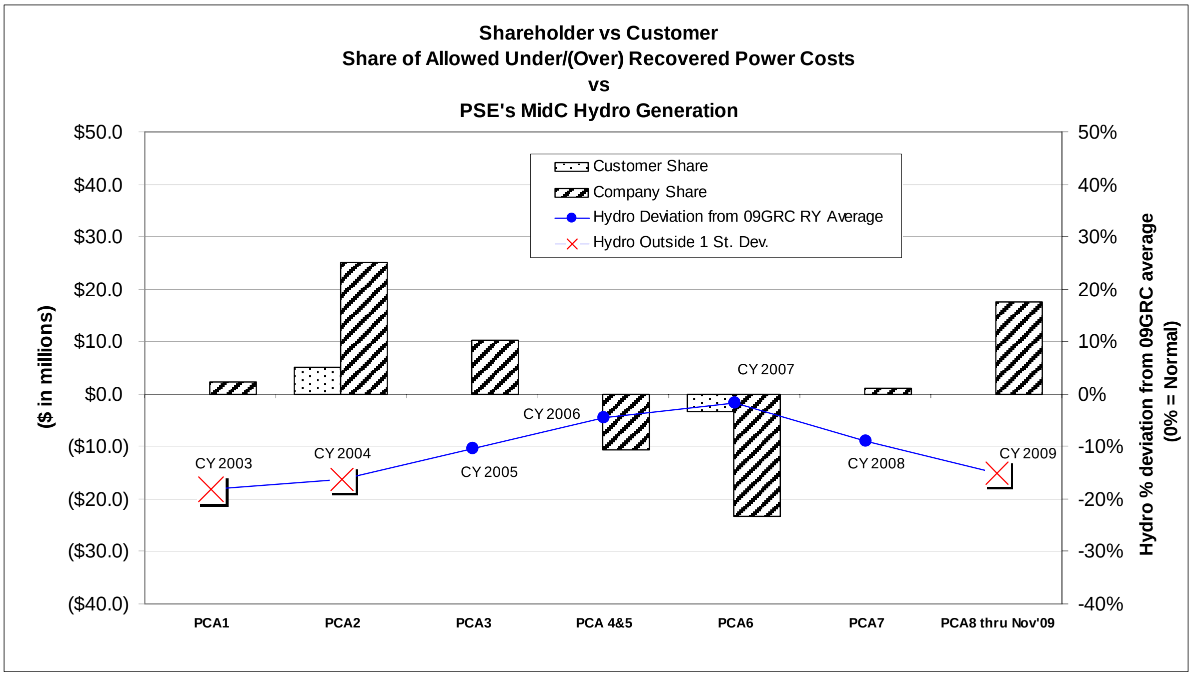
Table 4



Q. Were the costs associated with these years addressed in the PCA?

A. Yes. As shown above, PSE experienced an extreme loss in its ownership share of Mid-C hydro generation in years 2003, 2004 and is forecast to do so for 2009. The increased power costs resulting from these poor hydro conditions are included in the allowed costs tracked in the PCA mechanism. Over these three periods, shown in Table 5 below, PSE is forecast to absorb $44.9 million, or 90% of the PCA cost underrecoveries due to the PSE's obligation to cover the first $20 million of costs not recovered through rates. The very small portion of losses absorbed by the customer during those years may or may not be attributable to a loss of hydro generation as other factors contributed to underrecoveries during those periods.

Table 5



In total, the magnitude of the losses absorbed by the Company indicate the customer is currently not at risk for extreme hydro variability due to the $20 million PCA deadband.

Q. Does PSE recommend a change to the PCA Sharing Mechanism?

A. PSE has made such a recommendation – for instance, in PSE's 2006 general rate case, PSE proposed a change to the PCA mechanism to provide equal sharing of costs between PSE and customers, with no deadband. The analysis presented in that case specifically addressed the uncontrollable costs caused by hydro variability and how removal of the deadband, coupled with customer and shareholder sharing, was the appropriate methodology to recover such costs. PSE agreed to study the PCA mechanism again as part of the settlement of the 2007 general rate case, and PSE submitted its study to the parties to that case in December 2008. PSE received no comments from the parties in response to this study.

Q. What is the underlying philosophy for the forecast of projected rate year power costs that will be included in rates?

A. Clearly, recent history proves that so called "outlier" water years have occurred several times in the past several years. Exhibit No. JT-1CT at page 8, line 5. The projected rate year power costs included in rates should, therefore, reflect what is expected to occur in the rate year. As noted below, the best estimate for ratemaking purposes, of what hydro generation will be in the rate year, is the average of actual historical hydro generation data using at least fifty years of data.

In addition, the PCA mechanism is intended to be a balanced mechanism—one that should result in roughly an equal chance of under- or over-recoveries for both shareholders and customers. In other words, a PCA mechanism should, on average, be revenue neutral. An estimate of the Baseline Rate that is biased, as would likely result using the proposal of the Joint Parties, neither reflects what shareholders and customers can expect to occur in the rate year nor cures any possible design deficiencies in the PCA mechanism. Indeed, it is the PCA mechanism itself that may require adjustment, not projected rate year power costs.

Q. Has the Commission previously recognized that the Baseline Rate should be set as closely as possible to costs that are reasonably expected to be actually incurred during the rate year?

A. Yes. The Commission has previously recognized that the Baseline Rate should be set as closely as possible to costs that are reasonably expected to be actually incurred during the rate year:

> If the power cost baseline is set too low relative to actual prices, the greater the burden of those consequences for PSE's shareholders. Similarly, if the power cost baseline is set too high, ratepayers are burdened by the fact that they are paying more for power than what they should be paying. The PCA mechanism was meant to be fair to both shareholders and ratepayers.
>
> In summary, as we examine the power cost baseline from time to time—recognizing that it is important that we undertake that examination on a regular basis—we must strive to determine, with the greatest degree of precision that forward looking models can produce, an accurate estimate of actual costs that PSE will experience in the near and intermediate terms. It is a challenging task to estimate what the Company's actual costs of power will be in future periods, yet that is what we must strive to do so that the PCA mechanism functions, as intended, to balance the risk of excursions in power costs as equally as possible between ratepayers and shareholders.
>
> We resolve the philosophical question raised by ICNU in favor of the practical conclusion that power costs determined in general rate proceedings and in PCORC proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings.

Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc., Docket Nos. UE-040640, *et al*., Order 06 at ¶ 106-108 (Feb. 18, 2005).

Q. Are there other risks included in projected rate year power costs that should be considered when developing a PCA mechanism?

A. Yes. In establishing the Baseline Rate, it is reasonable to normalize many of the inherent variabilities of power costs. Rate year power costs include what is expected for each of the drivers based upon the best information available:

(1) weather uncertainty assumes a single forecast of normal temperatures and load;

(2) market variations in gas prices assumes a three-month average monthly gas price forecast which does not vary during the rate year;

(3) forced outages are based on historical averages; and

(4) wind generation is based on average modeled historical information.

A normal, or expected, power cost associated with these risks is included in the rate year power costs, along with the expected, or normal, hydro generation.

Q. Is water filtering just another way to normalize hydro generation?

A. No. Water filtering is simply a variation of the argument to eliminate low water years from determining average available resources. In effect, water filtering artificially maximizes a low cost resource and lowers projected rate year power costs when setting rates.

Q. If not through water filtering, how should the Commission normalize hydro generation?

A. Hydro generation is very difficult to forecast; therefore, analysts use historical streamflows to determine future hydro generation. The issue of the number years to include in hydro generation for modeling projected rate year power costs has been a matter of debate for a number of years.

Dr. Yohannes Mariam, witness for Commission Staff, and Dr. Jeffrey Dubin, witness for PSE, conducted the most recent analysis of the hydro streamflow and generation data in PSE's 2004 general rate case. As discussed in the rebuttal testimony of Dr. Dubin in the 2004 general rate case, Commission Staff and PSE concluded that *at least* fifty years of hydro information should be used when determining power costs for rate purposes. This conclusion stands in stark contrast to the Joint Parties' analysis in this rate proceeding. The Joint Parties, in this proceeding, would take a giant step backwards because their proposal considers only thirty years of hydro information. Please see the Prefiled Rebuttal Testimony of Dr. Jeffrey A. Dubin, Exhibit No. JAD-1T, for a discussion of the erroneous basis for the water filtering adjustment proposed by the Joint Parties.

Q. Do the Joint Parties correctly calculate the water filtering methodology they propose?

A. No. The Joint Parties utilized the entire Mid-C generation for each of the water years without considering the fact that PSE has varying contractual shares of the generation from the Mid-C hydro projects. It is PSE's share of the generation of the Mid-C projects generation that directly affects PSE's power costs in the AURORA model runs, not the total Mid-C projects generation (although total Mid-C generation does impact regional market prices).

Q. Does PSE offer a correction to the Joint Parties' hydro filtering adjustment to reflect PSE's share of the generation of the Mid-C projects generation?

A. Yes. If the Joint Parties had used only PSE's share of Mid-C hydro generation in its hydro filter calculation, the adjustment would have resulted in a $3.0 million reduction to projected rate year power costs, rather than the $4.6 million reduction calculated using the Joint Parties' approach. Please see Exhibit No. DEM-14C for a correction of the Joint Parties' calculation. Although PSE does not believe that the Joint Parties' proposal has any merit, PSE offers this correction to the Joint Parties' hydro filtering adjustment to illustrate the flawed analysis of the Joint Parties and not as an endorsement of such adjustment.

Q. Please explain what the AURORA model is modeling with the fifty years of hydro.

A. As stated above, the gas prices input into the AURORA model represent the three-month average gas prices at a given date and are a static forecast that does not vary over the fifty AURORA model runs. Each of the fifty AURORA model runs, therefore, uses the same monthly gas price with different hydro generation. This hydro generation causes variations in the AURORA-generated market price because less efficient generation units will be dispatched when hydro generation is scarce. In essence, the varying hydro generation drives the variability in the AURORA generated market heat rates and the resulting dispatch of PSE's gas fired generators is what creates variability in power costs.

B. Contested Power Cost Adjustments Proposed by Public Counsel

1. Rolling 50-Year Average Hydro

Q. Please discuss Public Counsel's proposed adjustment to PSE's rate year hydro generation.

A. Public Counsel proposes to use a more recent fifty-year hydro period, 1949-1998, to reflect "significantly higher" generation associated with PSE's ownership share of the Mid-C projects so that PSE will not have "significant over-recovery of power supply costs". Exhibit No. SN-1HCT at page 35, line 16. Public Counsel states that its adjustment increases PSE's rate year Mid-C hydro generation by 122,873 MWhs, and reduces rate year power costs by $5.6 million. *See* Exhibit No. SN-1HCT at page 35, line 18, through page 36, line 5.

Q. Is Public Counsel's hydro adjustment appropriate?

A. No. As explained in the Prefiled Rebuttal Testimony of Dr. Jeffrey A. Dubin, Exhibit No. JAD-1T, Public Counsel's proposal advocates for a 50-year rolling average that is arbitrary and without merit. Simply using a more recent period of data because it creates results favored by Public Counsel is not a valid reason to change the years of hydro information used to set rates. If Public Counsel wishes to use the more recent hydro data, then the full 70-year set of hydro data should be used to set PSE's rate year power costs. PSE's average ownership share of the Mid-C generation using the full 70-year data set is 26,157 MWhs *less* than the average using the hydro years 1929-1978.

Q. What is the Company's basis for using the 50-year hydro period 1929-1978?

A. In the Company's 2004 GRC, the Commission agreed with Staff and PSE's recommendation to use this 50-year hydro period in projecting power costs for the rate year. PSE had originally argued to use the full then-60-year period of data from 1928-1987, but had agreed to use 50-years of information in acknowledgement of Staff's argument that the recent ten years of data was not developed in a similar manner as the prior 50 years.

Q. Are there any issues in running the AURORA model with either the 50-year hydro period 1949-1998 or the full 70-year set of hydro data as recommended by Dr. Dubin?

A. Yes. The AURORA model databases used in this rate case include the fifty years of hydro data (1929-1978) used by PSE in its projected rate year power costs provided in its supplemental filing dated September 28, 2009, for the Mid-C projects, the Westside hydroelectric projects, and the Pacific Northwest areas modeled. The databases, however, do not currently include the data for the remaining twenty years (1979-1998) of the seventy-year period (1929-1998).

PSE has the generation data for the Mid-C and Westside plants for the full seventy years but does not have consistent data for the other Pacific Northwest areas included in the AURORA model. PSE provided Public Counsel with the generation data for the full seventy years for PSE's resources in PSE's Response to Public Counsel's Data Request No. 528.

Q. Does PSE have a recommendation regarding how to overcome this lack of data while utilizing all seventy years of available data?

A. Yes. If ordered to use the full seventy years of hydro data in this proceeding, PSE recommends

(i) the use of the average generation for the first fifty years for each of the remaining twenty years for the Pacific Northwest areas for which consistent data is not available and

(ii) the use of the available seventy-year data for the Mid-C and Westside projects.

This approach would account for the power generated by the Mid-C and Westside projects in PSE's resource portfolio for each of the seventy years. This approach, however, would not incorporate the secondary effects of the higher or lower regional hydroelectric generation on regional power prices and thus on the market power purchases and sales used to balance PSE loads and supply resources for the 1979-1998 period.

2. **Off System Sales of Power**

Q. Please describe the argument of Public Counsel that the secondary sales modeled by the AURORA model are understated and should not be used for setting rates in this proceeding.

A. Public Counsel makes the following argument that the secondary sales modeled by the AURORA model are understated:

> It appears from the results presented in Table 2 that the Aurora model is not accurately simulating the operations of PSE's system and regional market prices. This apparent problem, which affects the level and costs of both market purchases and market sales, raises a serious concern since the majority of PSE's rate year baseline power costs are derived from the Aurora model dispatch analysis.

Exhibit No. SN-1HCT at page 39, lines 2-6. In an attempt to remedy this perceived problem, Public Counsel recommends "that PSE's baseline power cost forecast for the rate year be adjusted to reflect the average annual volume of [off system sales] made by PSE over the last 5 calendar years." Exhibit No. SN-1HCT at page 39, lines 8-10.

Q. Does PSE agree with Public Counsel's assertion that the AURORA model produces incorrect results in its modeling of rate year secondary sales?

A. No. In asserting that the AURORA model is deficient in its calculation of market sales, Public Counsel is refuting the logic of the AURORA model output the Commission has approved for ratemaking purposes in all of PSE's recent rate cases. Public Counsel's proposal appears to be motivated by an attempt to lower projected rate year power costs rather than any concern over inaccuracy in the AURORA model's projection of projected rate year power costs.

Since 2002, the PCA mechanism has provided that PSE (and not its customers) would bear the first $20 million of any power cost under-recovery, regardless of whether the under-recovery was attributable, in whole or in part, to differences between the AURORA model power prices and actual power prices. Now, Public Counsel expresses concern that "PSE has consistently under-forecasted the volume of OSS [Off System Sales] by a large amount when setting its baseline power costs in past rate cases" and "the Company's baseline power rate will be overstated and will therefore tend to over-recover actual power costs during the rate year period." Exhibit No. SN-1HCT at page 37, lines 11-12, and at page 38, lines 9-11, respectively.

Q. Does the history of the PCA mechanism support Public Counsel's assertion that the Baseline Rates have been overstated?

A. No. As noted above, considering power cost under-recoveries have totaled $6.8 ***million*** of actual allowed PCA mechanism costs of $6.9 ***billion*** over a six and a half year period, the history of the PCA mechanism does not support Public Counsel's assertion that the Baseline Rates have been overstated. If Public Counsel's assertion were true, it seems that PSE should have been over-recovering power costs in the PCA mechanism. Indeed, PSE has under-recovered over $17 million of power costs in the first eleven months of the current PCA 8 period.

Q. How are rate year market purchases and sales determined in the AURORA model?

A. AURORA determines, on an hourly basis, whether it is more economical for PSE to dispatch its incremental generation unit or to purchase power within the AURORA-generated marketplace. If purchasing power is a lower cost option, AURORA will model PSE as purchasing power in the market at the AURORA-generated hourly market price. If AURORA modeled economics dictate PSE has more generation than needed to meet load, the AURORA model will model PSE as selling this power in the market at the AURORA-generated hourly market price. PSE also considers actual rate year short-term, fixed-price power purchases and sales contracts and includes them in the projected rate year power costs by including them in the AURORA model.

In addition, Public Counsel is looking at only part of the market transactions modeled by AURORA—market sales—and noting actual market sales are higher than AURORA modeled market sales. Certainly actual transactions will differ from modeled transactions—that is the nature of a forecast. If a comparison is to be made between modeled and actual market transactions, one must consider all market transactions—both sales and purchases. Public Counsel has completely ignored the fact that PSE is in a short position more often than in a long position, and that PSE's market transactions are more often market *purchases*.

Q. Please provide further information regarding actual market transactions compared to forecast market transactions.

A. Public Counsel compared actual sales transactions for each of the past six rate periods (without recognizing one rate period included only six months) to the forecast sales transactions. Table 6 below provides a more appropriate comparison of the forecast to actual rate period total market transactions for the past six rate cases.

Table 6

Puget Sound Energy Actual Market Transactions vs Projected

Dollars in Millions:

Rate Case	Projected Market Purchases	Actual Market Purchases	Increase Market Purchases	Projected Market Sales	Actual Market Sales	Increase Market Sales	Net Market Increase
04GRC	$ 132.2	$ 504.3	$ 372.1	$ (27.9)	$ (185.2)	$ (157.4)	$ 214.8
05PCORC	$ 194.4	$ 521.1	$ 326.6	$ (7.9)	$ (197.3)	$ (189.5)	$ 137.2
05PCORC Update (6 mos)	$ 100.2	$ 288.1	$ 187.9	$ (8.7)	$ (134.9)	$ (126.2)	$ 61.7
06GRC	$ 273.9	$ 540.1	$ 266.2	$ (7.5)	$ (224.3)	$ (216.8)	$ 49.4
07PCORC	$ 305.4	$ 538.2	$ 232.8	$ (6.2)	$ (191.1)	$ (184.8)	$ 48.0
07GRC	$ 335.3	$ 441.9	$ 106.6	$ (15.8)	$ (176.6)	$ (160.8)	$ (54.2)
Ave of 6 Rate Cases (66 months)	$ 243.9	$ 515.2	$ 271.3	$ (13.5)	$ (201.7)	$ (188.3)	$ 83.1

MWhs:

Rate Case	Projected Market Purchases	Actual Market Purchases	Increase Market Purchases	Projected Market Sales	Actual Market Sales	Increase Market Sales	Net Market Increase
04GRC	2,403,678	8,842,838	6,439,160	(625,383)	(3,190,496)	(2,565,113)	3,874,048
05PCORC	3,642,250	10,086,374	6,444,124	(229,486)	(4,219,116)	(3,989,630)	2,454,494
05PCORC Update (6 mos)	1,579,333	4,906,712	3,327,379	(181,863)	(2,477,069)	(2,295,206)	1,032,173
06GRC	4,332,974	9,619,746	5,286,772	(173,868)	(4,422,562)	(4,248,694)	1,038,078
07PCORC	4,728,688	8,856,870	4,128,182	(141,255)	(3,356,238)	(3,214,983)	913,199
07GRC	5,367,241	10,185,232	4,817,991	(310,360)	(5,149,365)	(4,839,005)	(21,014)
Ave of 6 Rate Cases (66 months)	4,009,848	9,545,050	5,535,202	(302,221)	(4,148,154)	(3,845,933)	1,689,269

Table 6 confirms Public Counsel's assertion that actual market sales are much higher than forecast but also demonstrates that *total* actual net market transactions (market purchases less sales) are much greater than forecast, on average, more than 1.7 million MWhs or $83.1 million greater than forecast

Q. Please explain why forecast market transactions would be so different from actual transactions.

A. The AURORA model considers the modeled resource portfolio available to PSE in determining whether to purchase or sell power in the market. The actual resources available to PSE will always differ from modeled resources due to the inherent nature of PSE's power supply portfolio, which contains a diverse mix of resources with widely differing operating and cost characteristics.

Q. What is PSE's recommendation regarding market transactions forecast in this proceeding?

A. PSE modeled the projected rate year power costs in this proceeding consistently with past rate proceedings. These projected rate year power costs are appropriate for setting rates. PSE recommends that the Commission use the market transactions generated by the AURORA model and the rate year fixed-priced contracts to determine rate year power costs.

Q. What adjustment does Public Counsel propose regarding rate year secondary sales?

A. Public Counsel has derived an arbitrary average margin of $2.00 per MWh for secondary sales—representing 5% of the AURORA modeled average rate year market sales prices—without any relevant basis in actual margin information. Public Counsel then proposes a reduction in rate year power costs by $5.1 million by multiplying their random margin by their proxy for rate year sales, which is equal to the average of the past five years' secondary sales volume above what is included in PSE's supplemental filing dated September 28, 2009. As discussed above, the Commission should reject Public Counsel's adjustment to rate year market sales.

Q. Does PSE agree with Public Counsel's proposal that PSE be required to account for actual off system sales revenues and margins?

A. No. PSE disagrees with Public Counsel's proposal that PSE be required to account for actual off system sales revenues and margins and urges the Commission to reject it. Although PSE tracks actual off system sales revenues, in order to determine margins associated with sales, PSE would need to be able to determine the cost of the power sold. In other words, PSE would have to be able to determine which specific resource produced the power sold. Due to the complexity of PSE's power portfolio, PSE does not currently have the ability to track the specific resource of the generation sold. To track the information requested by Public Counsel, PSE would have to significantly upgrade and modify its systems, which would require costs not planned in this proceeding.

V. REGULATORY PROPOSALS FOR GAS MARK TO MARKET AND GAS COSTS

A. Gas Mark to Market

Q. Please explain the proposals of the Joint Parties and Public Counsel to remove costs associated with the gas for power mark to market costs.

A. Both the Joint Parties and Public Counsel express concerns regarding the level of gas for power mark to market costs included in projected rate year power costs. The Joint Parties propose that the Commission create a rider that would expire March 31, 2011, to recover the gas for power mark to market costs so that PSE does not over-recover these costs. *See* Exhibit No. JT-1CT at page 23, line 9, through page 24, line 5. In the same vein, Public Counsel proposes the implementation of a $0.00201/KWh credit, effective April 1, 2011, to eliminate rate recovery associated with the gas mark to market. *See* Exhibit No. SN-1HCT at page 40, line 18, through page 41, line 6. Both proposals result in no recovery of any short-term mark to market costs post-March 2011, unless PSE resets rates beforehand. Please see the Prefiled Rebuttal Testimony of Mr. John H. Story, Exhibit No. JHS-14T, for further details regarding these proposals.

Q. Does PSE agree with the proposals of the Joint Parties and Public Counsel to remove costs associated with the gas for power mark to market costs?

A. No. PSE disagrees with the proposals of the Joint Parties and Public Counsel to remove costs associated with the gas for power mark to market costs. First, The

Joint Parties and Public Counsel inaccurately portray the mark to market as a one-time significant cost that should not be allowed to be included in base rates past the rate year. PSE is concerned that, with over a $1 *billion* dollar portfolio, there are many costs that may be singled out as "significant" and proposed to be recovered separately. For example, this is the first rate year in memory that [redacted] for the Colstrip units. As discussed in my prefiled supplemental direct testimony, this caused a $10.0 million reduction to rate year power costs, which will remain in general rates even though two Colstrip units have [redacted] past the end of the rate year.

Second, PSE does not engage in market speculation, taking risks and attempting to "beat the market" to make money for its customers. Instead, PSE seeks to remove the volatility from its power portfolio by hedging the price of gas for power. Therefore, there will always be a mark to market cost or benefit of the gas for power hedges transacted to fix the cost of gas for power. There will be a gain if the forward gas prices have increased since the transaction date. Conversely, there will be a cost if the forward gas prices have declined since the transaction date. Any proposal to remove any cost recovery associated with mark to market costs or benefits ignores the basic fact that, as long as PSE hedges, there will be mark to market. The Commission should reject any proposal to impose a rider for the mark to market costs that arbitrarily eliminates the cost at the end of a projected rate year.

B. Gas Trigger Mechanism

Q. Please describe Public Counsel's proposed "trigger" mechanism.

A. Public Counsel recommends the Commission implement a mechanism to "trigger" a power cost reduction whenever gas prices drop by 15% or more from the gas prices reflected in rates. Public Counsel correctly states that PSE's gas fired generation has increased over the past five years, which causes increased power cost volatility. Public Counsel, however, incorrectly concludes that PSE must update the Baseline Rate whenever there is a decline in gas prices. *See* Exhibit No. SN-1HCT at page 42, lines 4-13. Public Counsel's proposed "trigger" mechanism is overly simplistic and unworkable as proposed.

Q. Why is Public Counsel's proposed "trigger" mechanism overly simplistic and unworkable as proposed?

A. Public Counsel's proposed "trigger" mechanism is overly simplistic and unworkable because it focuses exclusively on natural gas prices without regard to any other variable that affects projected rate year power costs and would require PSE to recalculate all projected power costs to reset the Baseline Rate. This recalculation would likely require a rate proceeding similar to the power cost only rate case because gas prices are but one input into projected rate year power costs. Such recalculation would require PSE to rerun the AURORA model to reflect more recent gas prices, the possibility of new regional resources, updates for new power contracts, changes in power supply agreements, and revisions to load.

Moreover, Public Counsel's proposed "trigger" mechanism is unwarranted because gas prices are not the sole determinant in the need to update the Baseline Rate. For example, gas prices have decreased 30% from PSE's last general rate case filing, but PSE's projected rate year power costs are higher.

VI. UPDATED RATE YEAR POWER AND PRODUCTION OPERATIONS AND MAINTENANCE COSTS

Q. Is PSE providing an update to the projected rate year power costs filed in its supplemental filing dated September 28, 2009?

A. Yes. PSE is providing an update to the projected rate year power costs filed in its supplemental filing dated September 28, 2009. PSE has updated its projected rate year power costs for purposes of this rebuttal filing to include some, but not all, of power cost adjustments proposed by the Joint Parties. PSE has not incorporated any of the power cost adjustments proposed by Public Counsel.

A. Projected Production Operations and Maintenance Costs

Q. What are PSE's projected rate year production operations and maintenance costs?

A. PSE's projected rate year production operations and maintenance ("O&M") costs are $113.7 million, a decrease of $8.0 million from the projected rate year production O&M provided in PSE's supplemental filing dated September 28, 2009. Please see Exhibit No. DEM-15 for the rate year production O&M costs.

Please see the Prefiled Rebuttal Testimony of Mr. Louis E. Odom, Exhibit No. LEO-13CT, for a discussion regarding production O&M for the gas-fired generators and wind turbines, Mr. Kim W. Lane, Exhibit No. KWL-1T, for a discussion regarding the Snoqualmie and Baker licensing costs and Mr. Michael Jones, Exhibit No. MLJ-5CT, for further discussion regarding the rate year production O&M costs for the Colstrip units.

B. <u>Projected Rate Year Power Costs</u>

Q. What are PSE's projected total rate year power costs, including projected production O&M costs?

A. PSE's projected total rate year power cost, including projected production O&M costs, are $1,116.6 million, a decrease of $17.7 million from the projected total rate year power cost, including projected production O&M costs, provided in PSE's supplemental filing dated September 28, 2009. Please see Exhibit No. DEM-16C for the projected total rate year power costs, including projected production O&M costs, as reconciled with the projected total rate year power cost, including projected production O&M costs, provided in PSE's supplemental filing dated September 28, 2009.

Table 7 below also provides a summary of the projected total rate year power cost, including projected production O&M costs, as reconciled with the projected total rate year power cost, including projected production O&M costs, provided in PSE's supplemental filing dated September 28, 2009.

Table 7

Rebuttal Power Cost and Production O&M Adjustments ($ in Millions)		
Supplemental Power Costs		**$ 1,134.3**
Upper/Lower Baker Correction	$ (1.8)	
Westcoast Pipeline Benefit	(5.8)	
MidC Costs	(2.1)	
Total Uncontested		**$ (9.7)**
Grant PUD Power Auction	$ 3.5	
Westcoast Pipeline Addtional Benefit	(2.4)	
Regional Load Forecast	(1.1)	
Baker/Snoqualmie License (Prod O&M)	(1.0)	
Mint Farm (Prod O&M)	(4.2)	
Sumas (Prod O&M)	(1.2)	
Other Gas Fired Generation (Prod O&M)	(1.9)	
Hopkins and Wild Horse O&M)	0.3	
Other	(0.0)	
Total Contested		**$ (8.0)**
Total Power Cost & Prod'n O&M Updates		**$ (17.7)**
Rebuttal Power Costs		**$ 1,116.6**

Q. Should the Commission require an update to projected rate year power costs before the new rates go into effect?

A. Yes. The Commission should require an update to projected rate year power costs before the new rates go into effect. In that regard, the Commission has stated in PSE's general rate proceedings that the "power costs determined in general rate proceedings and in PCORC proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings," *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket Nos. UG-040640, *et al*., Order 06 at ¶ 108 (Feb. 18, 2005), and "the Power Cost Baseline Rate is the expected level of power costs around which PSE's power cost adjustment mechanism works," *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket Nos. UE-060266, *et al*., Order 08 at ¶ 99 (Jan 5, 2007). In this regard, the projected rate year power costs should be updated to reflect more recent gas prices, just prior to rates going into effect, so that they reflect the best estimate of the costs to be incurred in the rate year.

Q. How are the projected rate year power costs updated to reflect more recent gas prices?

A. The projected rate year gas price forecast input into the AURORA model should reflect a three-month average gas price as close as possible to the rate effective date. Rate year short-term fixed-price power and gas for power contracts at such date should also be included in the determination of the power costs. The short-term fixed-price power contracts are an input to the Aurora model, and the gas for power contracts are an adjustment included in the "Not in Models" calculation. In addition, some "Not in Models" adjustments, regulatory adjustments, and production O&M 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 the current three-month average rate year gas price?

A. The current three-month average rate year gas price as of December 4, 2009, was

$6.02 per MMBtu, and the average rate year gas price as of December 4, 2009, was $5.59 per MMBtu. The three-month average rate year gas price included in the current projected rate year power cost forecast is $5.97 per MMBtu.

VII. TENASKA AND MARCH POINT 2 DISALLOWANCE CALCULATION

Q. Please explain the calculation of the disallowance on the Tenaska regulatory asset.

A. The Commission's May 13, 2004 order in Docket UE-031725 provided that PSE is not allowed to recover a portion of its Tenaska-related costs in excess of the original Tenaska contract costs. If PSE's Tenaska-related costs are greater than the original Tenaska contract costs, the rate year power costs should be reduced by the lesser of 50% of that difference or 50% of the rate year return on the Tenaska regulatory asset. (Tenaska-related costs include fuel and contract related costs per the AURORA model, replacement power costs, tax timing differences, gas mark to market gains or losses, recovery of the Tenaska regulatory asset and return on the Tenaska regulatory asset.) Using the rate year rebuttal costs, the projected reduction is 50% of the difference in Tenaska costs and is shown in Table 8 below and included as Exhibit No. DEM-17C.

Table 8

	Tenaska Disallowance Calculation:	PSE Rebuttal
	Tenaska Reg Asset RY AMA	$ 47,565,333
	times After Tax ROR	7.34%
	After Tax Allowed Return	$ 3,491,295
A	pre Tax Allowed Return	$ 5,371,224
	Rate Year Costs	$ 206,590,522
	Rate Year Costs under Old Contract	$ 202,049,560
B	Rate Year Costs - Old Contract Costs	$ 4,540,962
	Lower of A or B	$ 4,540,962
	Disallowed %	50.00%
	Tenaska Disallowance	**$ 2,270,481**

Q. Did the power cost adjustments of either the Joint Parties or Public Counsel consider the Tenaska disallowance?

A. No. Neither the Joint Parties nor Public Counsel reflects the impact on the rate year forecast of the Tenaska disallowance. In years past, different rates of return ("ROR") caused changes in the calculation of the disallowance. However, in this proceeding, it appears that the disallowance may be determined by the difference between the rate year forecast costs for Tenaska and the costs under the original Tenaska contract.

Q. What is PSE's request regarding the Tenaska disallowance?

A. When power costs are determined for this rate proceeding, PSE requests the Commission consider the impact any changes will have to the Tenaska disallowance on the rate year power costs.

Q. Does PSE have a request regarding the disallowance for the March Point 2 or Tenaska power costs?

A. Yes. Rate year power costs should be reduced by 1.2% of the Tenaska-related fuel costs and 3.0% of the March Point 2 fuel costs. These costs are determined by the contract-related costs per the AURORA model, plus the replacement power costs. Therefore, whenever a new AURORA model run is used for the underlying power cost forecast, its generation and fuel cost output must be used to determine the costs subject to the regulatory disallowance. The change to the Joint Parties' power costs would be a decrease of $0.1 million. PSE proposes that when the rate year power costs are finalized that the disallowances for both Tenaska and March Point 2 be updated.

VIII. CONCLUSION

Q. Please summarize your testimony.

A. PSE has carefully considered all of the power cost adjustments proposed by the Joint Parties and Public Counsel. PSE has accepted the power cost adjustments proposed by the Joint Parties that relate to (i) projected generation for the Upper Baker River Project and the Lower Baker River Project, (ii) updated Mid-C contract costs to reflect more recent budgets from the public utility districts that operate the hydroelectric projects, and (iii) the corrected calculation for the Westcoast pipeline benefit. However, PSE urges the Commission to reject the other power cost adjustments proposed by the Joint Parties and all of the power cost adjustments proposed by Public Counsel.

The Commission should (i) adopt PSE's projected rate year power costs, based on the power cost adjustments proposed by the Joint Parties to which PSE can agree and updated information; and (ii) adjust projected rate year power costs for the Tenaska and March Point 2 regulatory disallowances.

PSE also encourages the Commission to reject both parties' proposals to segregate cost recovery of the gas for power mark to market and to retain such cost recovery until the baseline rates are adjusted at a later date. Finally, PSE recommends the Commission reject Public Counsel's proposal for a gas "trigger" mechanism.

Q. Does that conclude your prefiled rebuttal testimony?

A. Yes.