EXHIBIT NO. ___(DEM-19CT)
DOCKET NO. UE-060266/UG-060267
2006 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-060266** **Docket No. UG-060267**

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

REDACTED VERSION

REVISED AUGUST 25, 2006

PUGET SOUND ENERGY, INC.

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CONTENTS

PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Are you the same David E. Mills who submitted prefiled direct testimony in this proceeding on February 15, 2006, and supplemental prefiled direct testimony in this proceeding on July 10, 2006, each on behalf of Puget Sound Energy, Inc. ("PSE" or the "Company")?

A. Yes.

Q. Please summarize the purpose of your rebuttal testimony.

A. My rebuttal testimony responds to various statements and proposals for power cost adjustments made by Dr. Yohannes K.G. Mariam, testifying on behalf of the Staff of the Washington Utilities and Transportation Commission ("Commission Staff"), Mr. Jim Lazar, testifying on behalf of Public Counsel and Mr. Donald Schoenbeck, testifying on behalf of the Industrial Customers of Northwest Utilities (collectively referred to as the "Joint Parties").

The Joint Parties assert that there are major deficiencies in the input data and resulting hourly prices derived from the AURORA model. This is not the case. The input data used by PSE for AURORA modeling that the Joint Parties criticize is provided by EPIS, Inc., an independent third party and the developer of AURORA. The EPIS database provides a reasonable approximation of future market conditions. The AURORA model has been relied on, audited and approved for determining PSE's electric rates in similar proceedings since 2001, is widely used by other utilities and stakeholders within this region including the Bonneville Power Administration ("BPA"), and should be used for setting power costs in this case, as well.

PSE's support for continued use of the AURORA model in this case is not based purely on precedent. PSE has carefully considered each of the issues raised by the Joint Parties regarding the AURORA inputs. There is merit to one of the suggestions: increasing the AURORA model capacity by 2,281 megawatts to reflect updated information about certain generating resources that have been made to the EPIS database since the model run PSE used to prepare its original filing in this case. However, the Joint Parties' other recommendations with respect to the AURORA model, market prices and for determining peaking capacity costs should be rejected for the reasons outlined below.

My rebuttal testimony also responds to certain mis-statements and mistakes the Joint Parties make in: (1) comparing forward market prices with the prices PSE is obligated to pay pursuant to fixed-price contracts that it entered into over time; and (2) calculating the Tenaska disallowance.

Finally, I present an update of the Company's power cost projections for this rate case based on the Joint Parties' proposed adjustment to which the Company can agree.

II. BACKGROUND REGARDING MARKET PRICES

Q. The Joint Parties begin their testimony by revealing their "hope" at the time of the 2005 PCORC settlement in Docket No. UE-050870 that market prices would decline by the time PSE filed the general rate case required in that settlement.[1] Do you agree with their subsequent assertion that market prices have declined since the time the Commission approved the 2005 PCORC settlement?

A. I do not. The Joint Parties are comparing the prices in fixed-price contracts that PSE entered into during one period of time with forward market prices that happened to exist during another period of time. Specifically, they attempt to compare the following unrelated pricing points:

> (a) the average amounts paid or to be paid by PSE for energy under short-term, fixed-priced power contracts for July through December 2006 delivery that PSE had entered into as of April 28, 2006 over a time period of many months, and
>
> (b) the average Mid-Columbia ("MidC") forward market prices for each of the months in the same period, based on forward prices for each trading day during the 3-month period ending May 23, 2006 (see the Confidential table below).

[1] *See* Exhibit No. ___(JOINT-8CT) at page 5.

To show a decline in market prices, it would be appropriate to compare market price forecasts from the same data source at different points in time; it is not appropriate to compare average forward market prices over a three month period of time to an average cost of contracts committed over a different period of time.

Q. Can't one infer from this comparison that prices have declined, even if the comparison is not perfect?

A. No, it is incorrect to infer from the data offered by the Joint Parties that market prices have declined since the 2005 PCORC settlement. Whether market prices appear to have declined or to have increased is entirely a function of which forward prices one picks to compare with the average price of the fixed-price contracts PSE had already entered into over an extended period of time. For example, under the Joint Parties' suggested approach, if the same PSE contract amounts were compared to the Kiodex average MidC forward market prices at August 4, 2006, PSE's average cost would, in total, appear to be below market. These different comparisons are presented in the charts below:

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PSE on-Peak Purchases to Current Market Prices

	Per Joint Parties Exhibit No. ___(TC (JOINT-8TC) Page 6				PSE Calculation	
	On-Peak Purchases (MWhs)	PSE Cost ($/MWh)	Mkt Price 3-mo avg 5.23.06 ($/MWh)	Difference in Costs ($000)	Mkt Price at 8.4.06 ($/MWh)	Difference in Costs ($000)
Jul-06				-$2,017		$4,584
Aug-06				-$1,726		$272
Sep-06				-$4,510		-$2,117
Oct-06				-$5,363		-$4,229
Nov-06				-$2,821		-$1,422
Dec-06				-$1,202		$1,039
Jul-Dec '06				-$17,639		-$1,873

PSE off-Peak Purchases to Current Market Prices

	Per Joint Parties Exhibit No. ___(TC (JOINT-8TC) Page 7				PSE Calculation	
	Off-Peak Purchases (MWhs)	PSE Cost ($/MWh)	Price 3-mo avg 5.23.06 ($/MWh)	Difference in Costs ($000)	Mkt Price at 8.4.06 ($/MWh)	Difference in Costs ($000)
Jul-06				-$8		$1,731
Aug-06				$171		$275
Sep-06				$148		$332
Oct-06				-$1,161		-$911
Nov-06				-$224		-$35
Dec-06				$485		$1,255
Jul-Dec '06				-$589		$2,646
			Total Difference	**-$18,228**		**$773**

In short, the variability of factors involved in the pricing of transactions at MidC over one period of time is too great to provide a relevant point of comparison with the pricing of actual transactions entered into by PSE over a different period of time. Accordingly, it is incorrect for the Joint Parties to conclude that "PSE's current base purchase power cost…is almost $38 million greater than current forward prices."[2]

[2] *Id.* at page 7, lines 1-2

Q. Should the Joint Parties be "concerned" about the prices PSE paid for short-term, fixed-price power contracts included in the 2005 PCORC Update Filing, Docket No. UE-060783?

A. They should not, as PSE executed such contracts pursuant to its sound and robust hedging program. However, they will have an opportunity to analyze these contracts in the Company's annual Power Cost Adjustment ("PCA") mechanism compliance filing for the period about which they are concerned and may challenge PSE's prudence if they wish at that time. But this proceeding is concerned with determining rates for 2007; the Joint Parties offer no comparison of PSE contract prices to forward market prices for 2007 transactions.

Q. If PSE's contract prices for 2007 were higher than forward market prices for 2007 transactions, would that be a cause for alarm?

A. It should not be. PSE's power procurement efforts are not designed to "beat the market" by obtaining power at prices that are less than spot market prices at the time the power is consumed. Instead, PSE's primary purpose for executing commodity purchases is to reduce volatility and spot market exposure.

As discussed in my direct testimony, PSE follows a programmatic hedging plan, called the "Rolling [[redacted]]-Month Hedging Plan" (the "Plan") in determining the specific time periods and quantities for energy hedging.[3] This Plan is designed to

[3] *See* Exhibit No. ___(DEM-1CT), beginning at page 9.

reduce the Company's net power portfolio exposure starting [[redacted]] months in advance of delivery. Generally, this requires PSE to reduce its net power portfolio exposure each month, such that the net exposure by the end of each month falls within the range of exposure (stated in dollars) that is permitted in the Plan. The majority of the hedging strategies and transactions have been executed at least [[redacted]] months prior to delivery. Decisions for hedges made [[redacted]] months or less prior to the month of delivery are made by PSE under approved limits.

As further discussed in my direct testimony, one can make projections regarding future market movements, but one will never know at the time of executing a transaction how the future will actually unfold.[4] For this reason, the Company sees the benefit of a programmatic hedging strategy that is informed by fundamental analyses but that does not rely solely on discretionary market timing.

Q. What is the importance of this distinction regarding the purpose of PSE's short-term resource procurement efforts with respect to the Joint Parties' comparisons of PSE's contract prices with market prices?

A. Comparing a hedged purchase price to a current market price assumes 20/20 hindsight (or perfect foresight), which is impossible to achieve in real time evaluation. In addition, because PSE's hedging strategy is in many respects programmatic, the extent of its projected need for a given time period that is

[4] *See id*. at page 10.

covered by contracts for commodity purchases will depend on how close one is to that time period at the time of the projection. The percentage of projected resource needs covered by contracts at that point in time and the length of time over which they were acquired can also impact the comparison between an average hedged market price and current forward prices.

Q. If there actually were a "decline in forward market prices," should that be "factored into the power cost determination in this proceeding" as asserted by the Joint Parties?[5]

A. Not in the manner recommended by the Joint Parties. Fundamentally, PSE is not seeking to build into rates stale or inaccurate projections of power prices for the 2007 rate year. PSE's power cost projections in this case have been updated for current information. For example, PSE input into its updated AURORA model run for its July 2006 supplemental filing the average forward gas prices for the rate year during the 3 months ending May 23, 2006. Because AURORA uses these gas price inputs to model the economic dispatch or displacement of generating units (as described further below), this updated gas price information results in an updated market price forecast for the rate year, which is then incorporated in PSE's rate year power cost projections. I discuss in more detail in Section IV of my testimony why the Commission should reject the Joint Parties' proposal to replace the AURORA-generated market power prices with forward power prices for the rate year in this case.

Q. Does the Company's update filing contain a rate that is higher than the PCA Baseline rate approved in the 2005 PCORC Update Filing?

A. Yes. PSE's requested PCA Baseline rate in this rebuttal filing has increased $2.024 per megawatt-hour ("MWh"), from the current PCA Baseline rate of $56.901/MWh to $58.925/MWh. Contrary to the Joint Parties' inference, it is not just the variable power costs that are causing this increase.[6] Variable power costs included in PSE's requested PCA mechanism Baseline rate have actually *declined* by approximately $40.6 million. Rather, the PCA Baseline rate increase is due to recovery of (a) costs related to the Wild Horse wind generating facility, and more specifically, its costs of acquisition, return on investment, depreciation, transmission, property taxes, insurance and other revenue sensitive items, and (b) requested return on ratebase and production operation and maintenance costs.

III. AURORA MODEL INPUTS

Q. The AURORA model is the basis for the Company's power cost projections in this rate proceeding. Please describe this model.

A. AURORA 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

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[5] *See* Exhibit No. ___(JOINT-8CT) at page 7.
[6] *See id*. at page 8, line 5.

long-term--to imitate the functioning of wholesale power markets throughout the Western Electricity Coordinating Council ("WECC") region. It 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 AURORA is a forecast of wholesale market prices for power that assumes market participants have perfect foresight and make economically rational decisions, and that the market seeks and maintains continuous equilibrium. In addition to market-wide analysis, AURORA also has the capability to simulate hourly economic dispatch of a utility's generation resource portfolio.

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

A. Strengths of the AURORA model include:

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

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

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

(4) It is a standardized model that is widely used and understood by utilities, regulators, the Northwest Power and Conservation Council, BPA and others;

(5) It 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, AURORA 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, AURORA does not have sophisticated capabilities to model fixed costs (as opposed to variable costs), which is why PSE has to add in costs outside of AURORA, via the "Not in Models" workbook. Lastly, these AURORA characteristics make it difficult to compare total (fixed and variable) costs for different resource portfolio strategies.

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

A. PSE began implementation of the AURORA model in 1998 and has used it in all four subsequent Least Cost Plans ("LCPs"). The AURORA model was used in these LCPs to develop estimates of long-term power prices under multiple scenarios of loads, gas prices and environmental standards, as well as to project PSE resource needs. The Company is planning to use it for similar purposes in the 2007 Integrated Resource Plan.

PSE has also used the long-term power prices from AURORA as the estimated avoided cost schedule in Requests For Proposals for resource acquisitions. AURORA has been used to analyze and support our resource acquisitions decision for the Frederickson 1 acquisition in 2004 and for more recent wind turbine projects, Hopkins Ridge and Wild Horse.

PSE's electric rates have reflected the power costs modeled by AURORA since the 2001 general rate case, including the 2003 PCORC, the 2004 general rate case (GRC), the 2005 PCORC, the 2005 PCORC Update and, of course, this current proceeding. In each of these cases, the Company ran the AURORA model without making the kinds of adjustments the Joint Parties argue for in this case. The Company 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.

Q. The Joint Parties assert that there are major deficiencies in PSE's AURORA model inputs. How does PSE maintain the integrity of the AURORA database?

A. It is a complicated process to model the interactions of WECC resources--that is why AURORA is so detailed, with thousands of lines of data. This complexity is also why PSE relies on the economic and resource planning knowledge of AURORA's developer, EPIS, Inc., to maintain and provide periodic updates to its database, including regional resource specifications. PSE does modify some of the base data sets to consider PSE's more detailed and complete information regarding its owned and contracted resources, rate year gas prices and specific regional resource additions.

Q. What is your general response to the Joint Parties' assertion that PSE's AURORA model is producing incorrect results?

A. The Joint Parties' proposal appears to be motivated by an attempt to modify the model in their favor rather than concerns over inaccuracy in the model. During times when AURORA-modeled power prices were arguably lower than forward market power prices in the applicable rate year, intervenors did not raise any issues with respect to the AURORA model. 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 AURORA-modeled and actual power prices. Now, on the other hand, when forward market power prices appear (based on certain assumptions) to be lower than AURORA-generated power prices, the Joint Parties express concern.

Moreover, the Joint Parties indicate that their review has been piecemeal, stating that they "have not undertaken the labor-intensive effort to review each and every resource line (and column) of PSE's AURORA data set".[7] Candidly, the Company would not expect the Joint Parties to review each and every resource line and column, but it does not follow that downward adjustments to PSE's

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[7] *Id*. at page 9, lines 17-18

AURORA-derived power costs should be made outside the AURORA model based on a partial or arbitrary review. Therefore, except as specified below, the AURORA model should continue to be used and relied on in this proceeding, without adjustment, as it has been in the many proceedings and for the many purposes referred to above.

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--increase the likelihood that actual rate year power costs will be different from the power costs projected by the model. However, given such constraints, the AURORA model produces a valid and reasonable forecast of how PSE would operate its resources to serve its rate year load and provides the variable operating costs for its generating resources. It normalizes fifty years of hydro data by running fifty simulations. It models the Company's MidC contract generation in a manner that closely approximates historical data, dispatches 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. The AURORA model and its generated market prices produce a valid and reasonable forecast of rate year MidC market prices, as has been generally recognized in PSE's past six electric rate proceedings. The AURORA model should continue to be so recognized.

Q. Have you reviewed the Joint Parties' requests regarding AURORA input data included in the Joint Parties' prefiled testimony?

A. Yes. The Joint Parties request three particularized changes to "correct" the AURORA input data:

- Adding two generating plants and updating the capacity rating of several generating plants, primarily cogeneration facilities, to increase capacity by 2,281 megawatts;
- Changing the minimum up and down times of a number of gas-fired combustion turbine generating units; and
- Changing the shaping of the generation the Company receives from the MidC hydro projects.

A. Additional Plant Generation and Capacity

Q. Please describe your recommendations with regard to adding two generating plants and updating the capacity rating of certain generating facilities?

A. The Company reviewed the Joint Parties' requested changes and compared them to generating and capacity data and to sources contained in more recent versions of the AURORA input database, which were received after the initiation of this proceeding. While there appear to be some minor differences in the capacity ratings among the various data sources, the addition of the two generating plants and the changes to the cogeneration facilities' capacity ratings generally appear reasonable to PSE and consistent with the updated EPIS, Inc. database. The

Company accepts the suggested changes and has included them in the AURORA database used for this rebuttal filing.

Q. What is the impact to PSE's rate year power costs of adding these two generating plants and increasing the capacity rating of certain generating facilities?

A. The AURORA model variable power costs are reduced by approximately $4.0 million. After considering the effects of the AURORA model updates on the costs not in the AURORA model, such as marking contracts to market, PSE's rate year power costs are reduced by $3.2 million.

Q. Why didn't PSE just re-run its power costs using the entire updated EPIS database?

A. The EPIS database cannot be used "off the shelf" to project PSE's power costs because specific information about PSE's portfolio of resources must first be entered into the model, along with other calibration. PSE only received the updated EPIS database in June 2006. Furthermore, if PSE were to use this new software to generate power cost projections in the middle of a rate proceeding, it would prevent the other parties from having sufficient time to examine PSE's modeling. By holding the EPIS database version constant during a proceeding, other parties are able to check any updating performed by PSE as well as the ultimate compliance filing in a case relatively quickly. For these reasons, PSE made the capacity increase proposed by the Joint Parties as an update to the AURORA model run for this case rather than re-running the entire power cost projection on the most recent EPIS database release.

B. Minimum Up and Down Times for Gas-Fired Combustion Turbines

Q. Please describe the Joint Parties' requested changes regarding the minimum up and down time input parameters for new large Combined Cycle Combustion Turbines ("CCCTs").

A. The Joint Parties request changes to two of the input parameters used to specify the dispatch of a set of CCCTs. They request reduction of the minimum up times for these plants from [[redacted]] hours to [[redacted]] hours and reduction of the minimum down times from [[redacted]] hours to [[redacted]] hours.

Q. What is the basis for the Joint Parties' request to reduce the minimum up and down times?

A. The Joint Parties base their requested changes in the input data on three contracts totaling approximately 1,820 megawatts. One contract is between Southern California Edison ("SCE") and "a wholly owned subsidiary for the 1,000 megawatt Mountainview plant."[8] A second contract is for 520 megawatts between the California Department of Water Resources and the Sunrise Power

[8] *Id*. at page 14, line 21

Company"[9] and a third contract is for approximately 300 megawatts between SCE and the Kern River Cogeneration Company.

Q. For how many generating plants do the Joint Parties wish to change these data inputs?

A. The Joint Parties request that these changes in data input, which are based solely on the three contracts they cite, be applied to a total of 37 plants, amounting to over 23,000 megawatts of generating capacity.

Q. Please describe your recommendations with regard to the minimum up and down times changes requested by the Joint Parties.

A. The Company does not agree with the Joint Parties' suggested changes for several reasons:

1. The input parameters included in the Company's AURORA database are a reasonable, internally consistent set of data for large CCCT generating plants,

2. One of the most important factors impacting the maintenance costs of CCCT plants (and other thermal generating plants in general) is the number of "thermal operating cycles" (consisting of a start-up and shut down) a plant undergoes. The Joint Parties' requested changes do not consider the increase in maintenance costs caused by the increased thermal cycling of CCCTs that would be caused by the reduced minimum up and down times. Reducing the minimum up times from [[redacted]] hours to [[redacted]] hours and the minimum down times from [[redacted]] hours to [[redacted]] hours would increase the maintenance costs of these plants,

3. The requested changes do not recognize the restrictions to CCCT cycling operations imposed by air quality and other permits, and

[9] *Id*. at page 15, line 21

4. The requested changes do not recognize that the different operating characteristics of these 37 plants will cause the minimum up and down times of these units to vary from unit to unit:

   a. First, the contractual Long-Term Service Agreement relationship that exists between the plant operator and the service provider needs to be considered. These agreements specify the parameters under which a specific unit may be operated and may vary greatly from unit to unit. Items such as number of starts, ramp rates, and minimum run times are generally specified in these agreements. To assume that all of these generating plants can be modeled or operated in a similar manner is incorrect, and

   b. Second, the ownership structure of these 37 units will influence how the plants are dispatched. Specifically, the operating parameters between how a utility versus a merchant generator may operate a generating unit will vary. For example, a merchant generator with no load serving obligations may be willing to run the unit up and down on an hourly basis, simply to capitalize on the market heat rate. To assume that all 37 of these units can be modeled based on the same dispatch parameters is incorrect. Again, the input parameters included in the Company's database are a reasonable, internally consistent set of data for large CCCT generating plants.

Q. Has the Company estimated by how much the Joint Parties' requested changes would increase the plant maintenance costs?

A. Estimating plant maintenance cost increases is made difficult by not having access to the maintenance records of any of the 37 plants for which the changes are requested. However, based on the Company's experience with the operation of both simple cycle combustion turbine plants and CCCT plants, PSE estimates that these changes may increase the Variable Operation and Maintenance ("VOM") costs by $[[redacted]] to $[[redacted]] per MWh.

Q. Has the Company analyzed the impact of such increases in the VOM costs on projected power costs?

A. Yes. The AURORA database includes a $[[redacted]]/MWh VOM input value for the 37 plants for which the changes are requested. Increasing the VOM by $[[redacted]]/MWh and $[[redacted]]/MWh, as noted above, adds approximately $2.1 million and $3.7 million, respectively, to the Joint Parties' proposal, which estimated a reduction in power costs of $2.4 million. Taking these additional VOM costs into consideration, the Joint Parties' $2.4 million reduction would result in a decrease in power costs of as little as $0.3 million or even an increase to power costs of $1.3 million.

Q. Are there other reasons why reducing the minimum up and down times should be combined with an increase to variable O&M costs?

A. Yes, the Company's experience with the dispatch and operation of the Frederickson 1 generating plant indicates that plant starts are limited to [[redacted]] per day, in recognition of the detrimental operational effects of cycling the plant more frequently. The Company owns a 49.85% undivided interest in the Frederickson 1 plant, a relatively new, large CCCT generating facility located near Tacoma, Washington. The Dispatch Protocols (Exhibit B of the Joint Ownership Agreement for the facility) for this plant provide that the minimum time between a shut down and a subsequent start-up shall be [[redacted]] hours; however, the agreement further provides that the plant operation is restricted to [[redacted]] per day. This is due to a provision in the Long-Term Service Agreement between the plant owners and the firm contracted to provide plant maintenance. This restriction is imposed because the frequency of a CCCT's thermal cycling is a key determinant of maintenance costs. While the CCCT may be able *physically* to be cycled with more than [[redacted]] per day, the number of thermal cycles permitted is restricted to [[redacted]] per day. This restriction recognizes that any economic benefit of increased cycling would be more than offset by an economic detriment of increased maintenance costs.

Q. How do permitting requirements restrict the cycling operation of CCCT plants?

A. PSE reviewed the agreement between the California Department of Water Resources and Sunrise Power Company used by the Joint Parties as a basis for requesting minimum up and down time adjustments. The agreement provides that any plant dispatch shall be subject to the "Permit Limits." (Amended and Restated Confirmation Agreement (Tolling) entered into as of December 31, 2002, by the California Department of Water Resources and Sunrise Power Company, LLC, Section 5.01(d).) The "Permit Limits" schedule in that agreement provides that "No more than one Start-up of a Unit may occur on any day." (Schedule A, first paragraph under the heading "Phase 2.")

Q. What conclusion does the Company draw from these investigations?

A. It appears that increases in the maintenance costs associated with the Joint Parties' requested reduction in the minimum up and down times would offset the reduction in power costs resulting from such minimum up and down time reductions. Further, it is likely that environmental, other permitting restrictions and different operating characteristics would prevent plant operations as requested by the Joint Parties. For the reasons indicated above, the Company maintains that the input parameters included in the Company's database with respect to minimum up and down times are reasonable and internally consistent for large CCCT generating plants.

Q. Does the Company have additional concerns regarding the Joint Parties' minimum up and down times testimony?

A. Yes. First, the Joint Parties indicate that if a minimum up time is set to a period greater than 6 hours, a resource "could not be considered by AURORA" for a hypothetical peak load period of 6 hours or less.[10] This simply is not the case. AURORA dispatches resources based on economic benefits, not on a plant's minimum up or down time. The dispatch methodology only calls for a plant to have a positive economic value, i.e., to make money over the minimum up time. Second, the Joint Parties state that PSE's input parameters do not allow generating plants to be "ramped down overnight in anticipation of higher demands the next

[10] *See id*. at page 13, lines 9-18

day."[11] Again, this is not the case. The database used by the Company includes a parameter referred to as "minimum capacity," which specifies how much the plant can be ramped down during periods of lower prices in anticipation of higher demand the next day. In the case of the 37 generating plants selected by the Joint Parties, this parameter is set to [[redacted]]%, which allows a plant to run at [[redacted]]% of its full capacity for extended periods and to be ramped up within a single hour when demand increases.

C. Hydro Shaping

Q. Do you agree with the Joint Parties' assertion that the AURORA modeling does not produce reasonable on-peak generation from the Company's MidC hydro contracts?

A. No. The Joint Parties' assertion that the AURORA model does not shift enough hydro into high-value, on-peak hours is mistaken. Artificially shaping more of PSE's MidC contracts' generation into the highest value hours of the day disregards how hydroelectric systems are managed, specifically for non-power constraints. In addition, the Joint Parties failed to consider the actual historical shaping of the MidC generation.

The chart below compares historical on- and off-peak generation with what the Company has assumed in the AURORA run. As can be seen in the chart, the rate

[11] *See id*. at page 14, lines 14-18.

year AURORA-modeled shaping already requires PSE to increase its optimization of the MidC hydro by projecting an improvement to the percentage of on-peak generation in the rate year to 64.5%. This compares to an actual average historical on-peak operations percentage of 62.1%.

Compare 2007 Forecast to Annual Historical Averages

	Actuals							Forecast		
	7.01-12.01	2002	2003	2004	2005	YTD 6.06	Jul '01 - Jun '06	2007 AURORA	2007 KW	2007 Joint
On Peak MWh	1,346,186	3,799,950	3,441,084	3,420,307	3,516,310	1,952,002	3,495,168	3,685,721	3,873,445	3,880,801
Off Peak MWh	789,764	2,398,254	2,012,454	2,089,599	2,127,987	1,249,396	2,133,491	2,029,249	1,835,292	1,834,169
Total MWh	2,135,950	6,198,204	5,453,538	5,509,906	5,644,297	3,201,398	5,628,659	5,714,970	5,708,737	5,714,970
On Peak %	63.0%	61.3%	63.1%	62.1%	62.3%	61.0%	62.1%	64.5%	67.9%	67.9%
Off Peak %	37.0%	38.7%	36.9%	37.9%	37.7%	39.0%	37.9%	35.5%	32.1%	32.1%
Total %	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The Joint Parties propose to use MidC shaping of 67.9% for on-peak hours in setting power costs for this proceeding based solely on the fact that PSE's risk-assessment model has generated that figure. However, the risk-assessment modeled projection should not be used for setting rates.

Q. Why shouldn't the rate year hydro be shaped so optimistically for rate purposes?

A. The risk assessment model optimizes the MidC contract resource even more than either the actual historical or the forecast AURORA shaping. This provides PSE a "stretch goal" to create maximum value from this resource for operational purposes. However, the Company's risk assessment model is not capable of capturing all of the dynamic variables that negatively affect the ability to optimize on- or off-peak hydro generation, as discussed below. While the AURORA model is also limited in its ability to capture the impact of such variables, its hydro shaping forecast is closer to the actual average historical operations that PSE has been able to achieve, and thus is a more reasonable input for rate setting purposes.

Q. Please explain the hydro variables that restrict hydro optimization.

A. As more fully described below, non-power factors that limit the ability to optimize hydroelectric generation between on- and off-peak hours include (a) environmental restrictions, specifically operations mandated under the Biological Opinion, (b) reservoir restrictions, specifically flood control operations, (c) load factoring, (d) unit outages, (e) operating reserve requirements and (f) wind integration requirements.

(a) *Environmental restrictions* limit the ability to optimize generation between on- and off-peak hours by mandating specific project flow and reservoir requirements. These restrictions are put into place either to facilitate the upstream migration of adult anadromous fish or to expedite the downstream movement of juvenile species, depending on the time of year. These restrictions require specific minimum and maximum flow rates and oftentimes reservoir elevations--operations that may limit the ability to optimize generation based on price alone.

(b) *Flood control operations* mandate either the storage or evacuation of water from behind hydro projects to ensure that the hydro system is capable of containing spring run-off and meeting winter peak load requirements. This has a significant impact on PSE's MidC hydro operations as the MidC units are directly downstream from the Grand Coulee and Chief Joseph federal project dams. Grand Coulee is a principal storage reservoir for the Federal Columbia River Power System ("FCRPS"). Therefore, PSE is directly impacted by BPA's daily and hourly operating decisions, specifically as the FCRPS moves into and out of storage versus evacuation of water modes. This severely limits PSE's ability to independently manage hydro operations on the MidC projects.

(c) *Load factoring* refers to energy limitations on hydroelectric plants. Simply put, there is not enough fuel (water) to operate these units at maximum capacity for extended periods. As a result, these units tend to operate at lower overall capacity levels across hours.

(d) *Unit outages* refer to those periods where generators are not able to operate at full capacity due to planned or unplanned maintenance.

(e) *Operating reserve requirements* typically mandate that the Company carry reserves amounting to 5% on hydro and wind generating assets and 7% on its thermal generators. The Company, like many of its peers in the Pacific Northwest, uses hydro resources to meet a portion or all of its reserve obligations. Carrying reserves (typically spinning reserves) on a hydro unit means that the plant cannot generate up to its full capacity. For example, if the Company is generating 1,000 megawatts in a particular hour, split evenly between hydro and thermal generation, the Company would be required to carry 60 megawatts of operating reserves, 25 megawatts for the hydro generation component and 35 megawatts for thermal. During this hour, hydro capability would typically be decreased by 60 megawatts.

(f) *Wind integration* relies heavily on the flexibility of hydro generation. The intermittent and dynamic nature of wind generation requires that the Company hold hydro flexibility in reserve to honor or "firm" the wind generation schedule. Hydro is used to firm wind because of its instantaneous flexibility and relatively low cost. Our region recognizes the importance of the complicated process to integrate wind into our resource stack. BPA has recently assembled a working group of utility managers to fully consider how best to do so. As discussed in my prefiled testimony, PSE has included wind integration costs in its rate year power cost forecast.

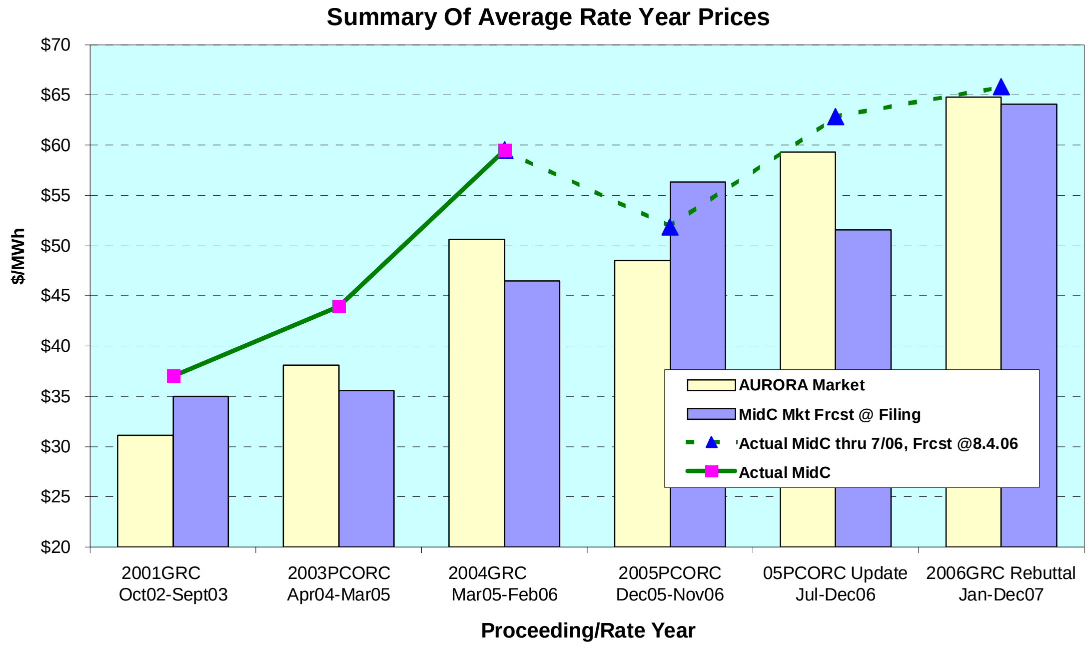
IV. RESPONSE TO JOINT PARTIES' REQUEST FOR MARKET PRICE ADJUSTMENTS

A. AURORA Modeled Prices Should Not Be Replaced By Forward Market Prices

Q. The Joint Parties state that the AURORA prices are wrong. Do you agree?

A. As described above, AURORA's modeled market price will never match forecast forward market prices, nor will they ever match the market prices that actually occur during the rate year. But this does not mean that they are "wrong" and should not be used for rate setting.

AURORA's track record of forecasting market prices for the rate years at issue in PSE's rate cases since 2001 is shown in the chart below. The bars in the chart show the AURORA forecast of market prices for the rate year compared to the forward market price forecasts for the rate year. The squares joined by the solid line show where actual market prices settled. The triangles joined by the dotted lines show a combination of actual market prices and recent forward market prices or just the recent forward market price forecast depending on whether actual market price information is yet available for the months in the rate year for the proceeding.



Q. What does the chart demonstrate?

A. For some proceedings, the AURORA-generated forward market prices have been higher than forward market prices and for some proceedings they have been lower. However, in no case to date have the AURORA-generated prices been higher than the market prices that actually occured during the rate year. Even when the market was forecast to be lower than AURORA, the actual average MidC prices came in higher. For the last three rate periods shown, which are still incomplete with respect to where actual market prices will settle, market prices (as of August 4, 2006) are again forecast to be higher than the AURORA-generated forecast.

AURORA's track record provides no reason to discard its modeled prices for the rate year in this case.

Q. Are there other reasons to use AURORA for determining rate year power costs?

A. PSE has used the model extensively over the past six electric rate proceedings. The Company has used AURORA not only for ratemaking purposes, but also for resource planning purposes. Commission Staff and other intervenors have been trained to use AURORA and possess fully licensed versions of the software (the cost of which is not prohibitive). Commission Staff, in particular, has used its own AURORA model to replicate and modify PSE's AURORA model results since PSE's 2001 general rate case. Also, AURORA's fundamentals-based dispatch abilities have been widely accepted by several utilities, such as Avista and BPA, for ratemaking, resource analyses and integrated resource planning.

Q. But what about the Commission's approval of the use of forward market prices for projecting rate year gas prices?

A. The Joint Parties' analogy to the forward *gas* price method that the Commission has approved as an input to AURORA fails to acknowledge the significant differences between the gas and power markets. The gas market and the power market each have different dynamics and causalities. One cannot simply assume--as the Joint Parties appear to do--that a three-month average MidC market forecast is reasonably predictive of actual electricity prices, without conducting more extensive analysis. The use of the three-month average of gas forward prices was proposed and adopted in the 2004 general rate case, during which

Dr. Jeffrey A. Dubin and Dr. Yohannes K.G. Mariam performed extensive statistical analysis that indicated the three-month average gas forecast is reasonably predictive of actual gas prices. Such analysis has not been presented in this case.

Q. What is your conclusion regarding how market prices should be projected for the rate year power costs?

A. For this proceeding, I strongly recommend that the Commission approve use of the AURORA model in the same manner as PSE has since 2001. While including the forward MidC market prices to model the rate year power costs does provide an alternative way of pricing market purchases and sales and the Company is willing to investigate this idea further, there are significant methodological and modeling issues that would need to be resolved before such a method could be implemented and appropriately used to set rates.

For example, the market prices developed using the current AURORA-based methodology are based on the average of the hydro conditions over 50 historical water-years, as well as normalized or average electrical loads (for both PSE and the region). Forward market prices, on the other hand, incorporate whatever hydro conditions, loads, and many other factors that are anticipated to occur at any point in time. If lower than average hydro generation (due to low stream-flow) is anticipated, forward market prices will tend to be higher than if higher-than-average hydro generation is anticipated. Similarly, expectations of temperatures that are different than normal impact forward prices. Because of the number of factors incorporated into the determination of forward market prices, the forward market prices tend to be much more volatile than AURORA's normalized or "fundamental" prices currently used to establish rates. Any alternative rate methodology using forward prices would need to allow for frequent updates based on then-anticipated conditions.

The simple fact is that no model will predict the market with perfect accuracy. Given that fact, it is appropriate to continue to use and rely on the full capabilities of the AURORA model to forecast power costs for the rate year. The inner workings of the AURORA model are all interdependent such that the least cost resource is dispatched to meet regional load, and more costly resources are dispatched to meet incremental load up to the variable cost of the gas fired units. The gas price input data determine the variable cost of gas-fired units to dispatch to meet the input regional load. Costs should generally be derived from a single model, rather than creating an inconsistent pastiche by puzzling together particular pieces from various other models or calculations. It is not sound practice to simply "cherry pick" from different models or inputs--such as hydro from PSE's risk system and power prices from the MidC forward market.

B. Even If AURORA Modeled Prices Are Replaced By Forward Market Prices, the Joint Parties' Proposed Methodology For Doing So Is Not Sound

Q. If the Commission nevertheless accepts the Joint Parties' recommendation to replace the AURORA modeled prices with forward market power prices, should it accept the Joint Parties' calculations that incorporate such replacement?

A. No, there are a number of inaccuracies in the way in which the Joint Parties propose to apply their proposed market price substitution, as described below.

Q. The Joint Parties' testimony states that PSE uses the AURORA-derived hourly values to price its projected market purchases.[12] Is that correct?

A. This statement is not entirely correct and may be misleading. Let me clarify how PSE's rate year market purchases are valued. 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 and price the quantity purchased at the AURORA-generated hourly market price. In this regard, PSE does not price its projected market purchases, AURORA does. However, PSE also considers actual rate year short-term, fixed-price power purchases and sales contracts and includes

[12] *Id*. at page 9, lines 1-2.

them in the projected rate year power costs by adjusting for these contracts in the "Not In Models" section of the rate year power cost calculations.

Q. If the Commission were to order PSE to re-price the AURORA market purchases, should it do so for 100% of the AURORA market purchases, as the Joint Parties propose?

A. No. PSE does not procure all of its market power needs in the short-term market. As shown in the table below, for actual market procurements in the first seven months of 2006, PSE purchased 42% of the market volume in the spot or real time market, compared to 58% in the short term market (transactions to settle, on average, two or more days in the future). Including the market sales, PSE obtained 72% of its net market purchases in the short-term market and 28% in the real time or spot market.

PSE's Actual Short Term, Exchanges, Real Time, Spot deals for Jan-July 2006

	S-T/Exch	Spot/R-T/Index	Total	S-T/Exch	Spot/R-T/Index	Total	ST/Exch	Spot/R-T/Index	Total
	Purchases			Sales			Net Purchases and Sales		
MW	789	574	1,363	(258)	(366)	(624)	532	207	739
MW	58%	42%	100%	41%	59%	100%	72%	28%	100%
# of Deals	281	9,692	9,973	101	6,987	7,088	382	16,679	17,061
% of Deals	3%	97%	100%	1%	99%	100%	2%	98%	100%

Q. What does this mean?

A. Although the Company strongly recommends against doing so, any re-pricing of the AURORA market purchases for PSE should exclude a portion to recognize PSE's spot and real-time purchases. According to actual data, only 72%, on average, of PSE's market power needs are purchased in the short-term market; the remaining 28%, on average, is purchased in the spot and real time market.

Q. Did the Joint Parties use a MidC forward price date consistent with the forecast gas price input?

A. No. The Joint Parties used the supplemental filing's 3-month average gas price at May 23, 2006, but used the 3-month average MidC power price at June 13, 2006--so their gas and power forecasts do not use the same period of forecast data. This apparently simple contradiction could have major effects on the rate year power costs. As I have discussed above, AURORA dispatches the least cost resource to meet regional load--with the gas price inputs determining the variable costs of the gas-fired units. The Joint Parties suggest that AURORA economically dispatch regional resources using gas prices from one period of time but then adjust PSE's market purchases with market prices from an unrelated period of time.

V. PEAKING CAPACITY COSTS

Q. What is your view of the Joint Parties' request that interested parties work together to derive a specific peak temperature to forecast extreme peak load in future filings?

A. PSE does not agree with the Joint Parties' request that peak temperature be based on the historical temperatures experienced over the same time period used for weather normalization, but PSE is open to examining further the appropriate historical period to be used in determining the design peak temperatures. Also, PSE does not agree with the Joint Parties' claim that it is a remote possibility that PSE will incur about $1 million in power costs to meet an extreme peak December 2007 deficit.[13] Nonetheless, PSE is receptive to collaborating with concerned parties with a view to agreeing upon which historical period to use in determining "design" peak temperatures.

VI. TENASKA DISALLOWANCE

Q. Did the Joint Parties' power cost request appropriately consider the Tenaska disallowance?

A. No, the Joint Parties' power cost request did not reflect the impact on the rate year forecast Tenaska disallowance caused by their proposing a different rate of return ("ROR"). If the Joint Parties' had adjusted the Tenaska disallowance to be consistent with their proposed relief in this case, their proposed rate year power costs would increase by $1.1 million.

Q. Please explain how the disallowance on the Tenaska regulatory asset is determined.

~~A. No, the Joint Parties' power cost request did not reflect the impact on the rate year forecast Tenaska disallowance caused by their proposing a different rate of return~~

[13] *See id*. at page 41, lines 9-11

~~("ROR"). If the Joint Parties' had adjusted the Tenaska disallowance to be consistent with their proposed relief in this case, their proposed rate year power costs would increase by $1.1 million.~~

~~Q. Did the Joint Parties' power cost request appropriately consider the Tenaska disallowance?~~

A. The WUTC'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. Simply put, if PSE's forecast Tenaska-related costs are greater than the original Tenaska contract costs, the rate year power costs should be reduced by the lesser of the difference or 50% of the rate year return on the Tenaska regulatory asset. (Tenaska-related costs include gas costs, recovery of the Tenaska regulatory asset and return on the Tenaska regulatory asset.) For the rate year, the projected lesser reduction is 50% of the rate year return on the Tenaska regulatory asset. The Tenaska disallowance for the rate year, using PSE's requested ROR, is calculated below:

Tenaska Disallowance Calculation:		
Tenaska Reg Asset RY AMA	$	142,925,000
times After Tax ROR		7.57%
After Tax Allowed Return	$	10,819,423
Pre Tax Allowed Return		16,645,265
Disallowed %		50%
Tenaska Disallowance	$	8,322,633

VII. UPDATED RATE YEAR POWER COSTS

Q. Have you updated power costs since PSE's Supplemental Filing in July 2006?

A. Yes, the Company updated its power costs for purposes of this rebuttal testimony to include one of the Joint Parties' requested power cost adjustments. As noted above, PSE adjusted the regional generation facilities in the AURORA model, which decreased rate year power costs by $3.2 million. As discussed above, PSE does not agree with or incorporate the Joint Parties' other requested changes to the rate year power costs for purposes of this proceeding.

Q. Did the Company adjust the rate year production O&M as proposed by Mr. James Russell of Commission Staff?

A. PSE's forecast rate year production O&M costs have not been modified from the Supplemental filing and accordingly do not include Commission Staff's suggested adjustments. Please see Mr. Kris Olin's and Mr. John Story's rebuttal testimony, Exhibit No. ___(KO-10T) and Exhibit No. ___(JHS-19T) for further discussion regarding the Muckleshoot Indian Tribe settlement payment and Baker Hydroelectric Project relicensing costs.

Q. What is the Company's current rate year power cost estimate?

A. PSE's rebuttal filing rate year power costs, including production operation and maintenance costs, are $965.2 million, a decrease of $3.2 million from the Supplemental Filing. The updated rate year power costs are provided in Exhibit

No. ___(DEM-20). The rate year power costs, reconciled to the As-Filed and the Supplemental filed rate year power costs, are provided in Exhibit No. ___(DEM-21).

Q. How would rate year projected power costs for this proceeding change if the Wild Horse Project were not included as a resource?

A. PSE ran the AURORA model with the same assumptions as for the rate year power costs presented in this proceeding, except the Wild Horse Project was removed. The model showed that, without the forecast generation from the Wild Horse Project, PSE would need to purchase additional power, or would be unable to sell excess power, in the market, for a total increase in power costs of approximately $40.2 million. Including other costs associated with the Wild Horse Project, power costs would increase $27.7 million. *See* Exhibit No. ___(DEM-22).)

VIII. CONCLUSION

Q. Please summarize your testimony.

A. PSE has carefully considered all of the Joint Parties' requested power cost adjustments. PSE has accepted the Joint Parties' recommendation to adjust the AURORA database for generating plant additions and capacity ratings for changes that have been made by EPIS, Inc. to the AURORA model database since the AURORA run that the Company used for filing its original case in this proceeding. However, PSE urges the Commission to reject the Joint Parties' other requested power cost adjustments for the reasons described above.

Q. Does that conclude your rebuttal testimony?

A. Yes.