EXHIBIT NO. ___(DEM-15T)
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 SUPPLEMENTAL
DIRECT TESTIMONY (NONCONFIDENTIAL) OF
DAVID E. MILLS
ON BEHALF OF PUGET SOUND ENERGY, INC.

JULY 7, 2006

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Are you the same David E. Mills who provided prefiled direct testimony in this Docket on behalf of Puget Sound Energy, Inc. ("PSE" or "the Company")?

A. Yes.

Q. What topics are you covering in your supplemental direct testimony?

A. I am updating the projected rate year power costs submitted with my direct testimony for changes that have occurred since the time of the original filing in February 2006.

Q. Please summarize your testimony regarding the update of power costs.

A. Projected rate year power costs in this supplemental filing are $968.4 million, a $2.9 million increase from the originally filed power costs of $965.5 million. This is the net result of certain costs going up and other costs going down from the power costs projected for the February 2006 filing, based on updated information available to PSE. The updated power costs are provided in Exhibit No. ___(DEM-16). As discussed by Mr. John Story in his supplemental testimony, Exhibit No. ___(JHS-15T), Mr. Story used these updated power costs, plus other data, to adjust the revenue deficiency for the rate year.

II. UPDATE TO PROJECTED POWER COSTS

Q. Have you reconciled the projected power costs filed in February 2006 to the updated projected power costs?

A. Yes. The table below details the changes to the projected rate year power costs since the February filing.

Description	Projected Rate Year Power Costs ($ in thousands)
As filed February 15, 2006	$ 965,541
Update AURORA Model	(5,672)
Coal Cost Update	2,438
MidC Power Contract Update	5,650
Transmission Cost Update	(3,826)
Production O&M Cost Updates	4,160
Miscellaneous	113
Total Updates	$ 2,863
As Updated July 2006	$968,404

A more detailed reconciliation between the power cost projections is provided in Exhibit No. ___(DEM-17).

Q. How did the Company update its power costs for the rate year?

A. PSE updated forward market gas prices and regional resource assumption inputs to the AURORA hourly dispatch model. In addition, cost projections outside of the AURORA model were updated to reflect these and other changes as noted below.

A. <u>AURORA Model and Gas Price Updates</u>

Q. What natural gas prices did the Company use for the rate year in running its AURORA model for this supplemental testimony?

A. PSE used a three-month average of daily forward market gas prices for the rate year for each trading day in the three-month period ending May 23, 2006. These data were input into the AURORA model for each of the months in the rate year. This is the same methodology as described in my original prefiled direct testimony except that it uses the more recent three-month period described above.

For purposes of comparison, the updated average price at Sumas for the rate year resulting from use of the updated information is $8.57/MMBtu, which (coincidentally) is the same average price included in this proceeding's original filing. This compares to the average rate year price at Sumas of $6.54/MMBtu for the original 2005 PCORC filing and $5.60/MMBtu for the 2004 general rate case.

In addition, projected power costs have been adjusted outside of the AURORA model to properly reflect fixed-priced natural gas and power contracts in place at May 23, 2006 for PSE's rate year power portfolio.

Q. Were any changes made to the AURORA database for this revised filing?

A. Yes, the EPIS database used in this proceeding's originally filed power costs was updated to the most recent April 2006 database "North_American_DB_2005.02". Three adjustments were made to the AURORA database to bring the resource tables up to date.

1. The new resources that have either come on-line or are definitely scheduled to come on line through 2007 were added to the resource data table. Approximately 6,595 MW of largely natural gas-fired resources were included in the April 2006 database that were not included in the original database.

2. Renewable Portfolio Standards ("RPS") resources assumed by the Company to come on-line, but are not scheduled to be built, were removed from the resource data table. The Company removed 3,060 MW of new RPS resources, largely wind plants, from the resource data table.

3. New resources added based on AURORA's long-term optimization logic, which either have not been, nor are scheduled to be, added were removed from the resource modifier data table. There were 52 wind plants, with a total capacity of 5,200 MW in this category.

Overall, the AURORA database' regional capacity from new resources was increased 6,595 MW for largely gas-fired generation and decreased 8,260 MW for, in large part, wind plants, for a net decrease of 1,665 megawatts to regional capacity from new resources. However, since wind plants have a lower capacity factor and, therefore, in general, don't produce as much energy per megawatt of capacity as gas and coal-fired plants, regional *energy* has *increased*. The increase in regional energy production reduces regional power prices, and as a result, power costs. In addition, there were several minor resource and contract input updates to the AURORA model. The AURORA modeled power costs for the rate year decreased $3.8 million due to the updates to forecast gas prices, regional resource assumptions and resource and contract data.

Q. Did forecast power costs outside of the AURORA model change as a result of the update to rate year gas prices?

A. Yes. As I noted above, projected power costs have been adjusted outside of the AURORA model to properly reflect fixed-priced natural gas and power contracts in place at May 23, 2006 for its rate year power portfolio. The combination of updating the forecast rate year gas prices and including new short term fixed-priced natural gas and power contracts at May 23, 2006 decreased rate year power costs by $1.9 million.

B. <u>Coal Price Update</u>

Q. Please explain the change to projected rate year coal costs.

A. Cost estimates for rate year coal costs were updated to reflect more recent coal cost information. Colstrip Units 1&2 coal costs were updated to reflect the March 2006 semi-annual contract cost adjustment and the first quarter 2006 royalty billings. Colstrip Units 1&2 rate year variable commodity coal costs increased an average of $0.35/MWh, from $8.82 to $9.17, with a resulting $1.1 million increase in power costs. Colstrip Units 3&4 updated coal costs are now based upon a June 2006 forecast, compared to the original filing cost support dated August 2005. Colstrip Units 3&4 rate year variable commodity coal costs increased an average of $0.52/MWh, from $8.12 to $8.64, with a resulting $1.2 million increase in power costs. These variable cost increases, along with minor changes to the fixed coal costs, increased projected rate year power costs $2.4 million.

C. Mid-C Power Contracts Update

Q. What caused the increase to the Mid-Columbia ("Mid-C") power contracts?

A. The majority of the increase to PSE's rate year Mid-C power contract costs is due to an inadvertent omission in PSE's original filing related to Grant County PUD's Priest Rapids Development's Meaningful Priority contract. Appropriately including this contract cost within the rate year increased power costs $6.3 million. Corrections to the cost calculation for the Priest Rapids Displacement Product, and other minor changes, reduced power costs by approximately $0.7 million, for a total Mid-C cost increase of $5.7 million.

D. Transmission Cost Update

Q. Please explain the change to transmission costs for the rate year.

A. As discussed in my original testimony, Exhibit No. ___(DEM-1CT), in December 2005, PSE requested from BPA additional firm transmission from the Mid-C to PSE's system. In response to PSE's request, BPA determined they could only offer a lesser amount of transmission due to a limited amount of Available Transfer Capability ("ATC"). The updated proforma rate year power costs have been reduced by $1.7 million to reflect BPA's offer of less transmission capacity. PSE is currently reviewing and responding to BPA's offers, with the expectation that the contracts will be finalized by the end of August 2006. This, as well as updates to the expected rate year BPA transmission rates and correcting the transmission cost calculation for Hopkins Ridge, has reduced power costs $3.8 million.

E. <u>Production O&M Cost Update</u>

Q. How has PSE updated its forecast of Production Operation and Maintenance costs in this supplemental filing?

A. To update its rate year power costs, PSE has made the following adjustments to its originally filed production operation and maintenance ("O&M") costs:

i) Updated the proforma Colstrip O&M costs to reflect a more recent, May 2006, business plan of rate year O&M costs, for a total cost increase of $3.0 million;

ii) Revised the O&M costs projection associated with the Snoqualmie Hydroelectric Project and with the FERC relicensing of the Baker River Project for a cost increase of $0.4 million;

v) Updated the O&M costs for the Frederickson 1 resource to reflect PSE's expected ownership share of costs and to update the expected rate year major maintenance costs for a total cost increase of $0.8 million;

vi) Updated the proforma Fredonia 3 & 4 lease costs to reflect the lease costs expected in the rate year for a cost increase of $0.1 million; and

vii) Updated normalized major maintenance for PSE's owned simple-cycle gas and oil-fired combustion turbines and PSE's owned Encogen plant for changes in expected rate year generation, for a power cost decrease of $0.1 million.

In total, PSE's rate year production O&M costs are $80.5 million, an increase of $4.2 million from the originally filed production O&M costs.

III. PROJECTED POWER COSTS WITHOUT THE WILD HORSE PROJECT

Q. How would rate year projected power costs for this case 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 supplemental filing, except removed the Wild Horse Project. The model showed that, without the forecasted 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 $40.8 million, as compared to $40.1 million in the original filing. *See* Exhibit No. ___(DEM-18).

Q. Does this conclude your testimony?

A. Yes, it does.