EXHIBIT NO. ___(MLJ-1CT)
DOCKET NO. UE-11___/UG-11___
2011 PSE GENERAL RATE CASE
WITNESS: MICHAEL L. JONES

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF
MICHAEL L. JONES
ON BEHALF OF PUGET SOUND ENERGY, INC.

REDACTED
VERSION

JUNE 13, 2011

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF MICHAEL L. JONES

CONTENTS

PUGET SOUND ENERGY, INC.

PREFILED DIRECT TESTIMONY (CONFIDENTIAL) OF MICHAEL L. JONES

I. INTRODUCTION

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

A. My name is Michael L. Jones. My business address is 10885 N.E. Fourth Street, Bellevue, WA 98004. I am Asset Manager, Thermal Joint Ownership and Power Contracts for Puget Sound Energy, Inc. ("PSE").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(MLJ-2).

Q. What are your duties as Asset Manager, Thermal Joint Ownership and Power Contracts?

A. I am responsible for the management of PSE's ownership and contract interests in the four-unit Colstrip Steam Electric Station in Colstrip, Montana ("Colstrip"). My responsibilities include oversight of plant operations, environmental issues, budget performance and the Colstrip fuel supply contracts. I am also responsible for managing PSE's ownership interests in the Frederickson 1 combined cycle facility and for managing thermal power purchase agreements.

Q. Please summarize the purpose of your prefiled direct testimony.

A. My prefiled direct testimony provides background regarding Colstrip. My testimony also explains the current capacity levels of the four Colstrip units and the factors used to determine the availability and the schedule of planned plant maintenance overhauls. I will also discuss Colstrip's costs and other Colstrip information used to produce PSE's power cost projections, which are described in the Prefiled Direct Testimony of David E. Mills, Exhibit No. ___(DEM-1CT).

II. BACKGROUND REGARDING THE COLSTRIP STEAM ELECTRIC STATION

Q. What is the Colstrip Steam Electric Station?

A. Colstrip is a four-unit, mine mouth, coal-fired electricity-generating facility operated by PPL Montana, LLC ("PPL") in Colstrip, Montana, about 120 miles southeast of Billings. Colstrip is capable of producing up to 2,094 megawatts ("MW") of electricity. Colstrip includes four generating units: Units 1 and 2, which are each rated at 307 MW of net generating capacity, and Units 3 and 4, which are each rated at 740 MW of net generating capacity. Units 1 and 2 began commercial operation in 1975 and 1976, respectively, and Units 3 and 4 began commercial operation in 1984 and 1986, respectively.

Q. What is PSE's interest in Colstrip?

A. PSE owns a 50 percent undivided interest in Units 1 and 2 and a 25 percent undivided interest in Units 3 and 4. The 94 MW purchased power contract between PSE and NorthWestern Energy, for a portion of NorthWestern Energy's Colstrip Unit 4 output, ended in December 2010 and is no longer included in future projections. In total, Colstrip provides about 20 percent of PSE's overall energy needs.

III. COLSTRIP AURORA MODEL INPUTS

Q. Please explain the term "forced outage rate" as used for forecasting power costs.

A. In the context of forecasting power costs, the forced outage rate ("FOR") is the percentage of time that a unit is not available for power production for reasons such as maintenance outages and forced outages or deratings.[1] PSE uses the FOR to model the availability of the Colstrip units in estimating power costs. The FOR does not include the time that a unit is unavailable due to the planned overhaul of each unit because the dates and durations of these planned overhauls are separately accounted for in the AURORA power cost model.

Q. What method did PSE use to determine the FOR in this proceeding?

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[1] The term derating refers to operating a machine at less than its rated maximum power due to ambient conditions or equipment limitations.

A. Consistent with the method used in both the 2007 general rate case ("GRC"), Docket No. UE-072300 and UG-072301,[2] and PSE's 2009 GRC, Docket Nos. UE-090704 and UG-090705, the FOR used in this proceeding is based on the average FOR over the most recent four calendar years, 2007 through 2010. Because of the differences in design and equipment suppliers between Units 1 and 2 and Units 3 and 4, PSE applies one FOR to Units 1 and 2 and another FOR to Units 3 and 4.

Q. How do the results of the FOR calculation in this proceeding compare to the results of the last general rate case?

A. In its 2009 GRC, PSE calculated the FOR by using actual data from years 2005 through 2008 (9.6 percent for Units 1 and 2 and 5.9 percent for Units 3 and 4). For this proceeding, the FOR for Units 1 and 2 decreased to 8.8 percent, yielding an increase in rate year available generation of nearly 21,000 MWh compared to PSE's 2009 GRC. The FOR for Units 3 and 4 increased to 10.2 percent, partly due to the extended Unit 4 outage in 2009, reducing available rate year generation by about 135,000 MWh compared to PSE's 2009 GRC. Please see the Second Exhibit to my Prefiled Direct Testimony, Exhibit No. ___(MLJ-3C) for the data used to calculate the FOR in this proceeding.

[2] *See* 2007 GRC, Prefiled Rebuttal Testimony of Michael L. Jones, Exhibit No. MLJ-15T, at 2.

Q. Is the FOR reported to the North American Electric Reliability Corporation ("NERC") Generator Availability Data System the same as the FOR PSE used to calculate power costs?

A. No. The FOR used for Colstrip in the AURORA power cost model is not the same as the FOR reported to the NERC Generator Availability Data System ("GADS") database. The GADS FOR is lower than that used in AURORA because it is tracking only one type of outage. The GADS FOR includes only the time that a unit is *forced* offline or suffers a *forced* derating. PSE's FOR in the AURORA power cost model includes both forced *and planned* outages and deratings, except the planned triennial overhauls. For this reason, PSE's FOR for Colstrip will always be higher than the NERC's FOR. If planned outages were not included in the power cost modeling, the effect would be to overestimate the availability of the unit and understate forecasted power costs.

Q. Please describe the forced outage to Unit 4 in 2009.

A. Colstrip's Unit 4 steam turbine-generator contains two low-pressure sections that remove the last energy from the steam before it is exhausted to the condenser. Each low-pressure section includes an element called the rotor that rotates at 3600 revolutions per minute when the unit is producing energy. During the 2009 overhaul of Unit 4, an inspection of these rotors was conducted, as recommended by the turbine-generator manufacturer, Siemens. Inspection of the face of the connection of the rotor shaft to the last stage blades revealed a crack in the metal holding the blade to the shaft on one rotor. Blades were removed from both rotors and further inspection showed cracks in this area in both rotors. The manufacturer recommended repairing the cracks before returning the rotors to service. An independent consultant hired by the owners agreed with Siemens' recommendation. Both 60-ton rotors had to be returned to a Siemens shop in Charlotte, North Carolina for the repair.

The Unit 4 planned overhaul started on March 28, 2009 and was scheduled to end 55 days later, on May 21, 2009. The necessity of repair of both rotors delayed the Unit 4 restart for five months - until October 29, 2009.

Q. Should the long forced outage of Unit 4 in 2009 be included in the FOR calculation?

A. Yes. In past proceedings, certain parties have advocated eliminating years in which a Colstrip unit experienced a high forced outage rate, arguing that such years were unusual and should not be expected to re-occur. This, in fact, is not the case: the number of components needed to operate the units safely can cause a high forced outage rate even though a single component rarely fails. As is typical for units of Colstrip's size, there are certain major components that have no redundancy, such as the boiler, the steam turbine, the generator and the condenser circulating water system. While these components are highly reliable, if any one suffers damage, it is impossible to generate any energy until the component is repaired or replaced. This was the case in 2009, when the two low-pressure turbines needed repair. As shown in Exhibit No. ___(MLJ-3C), the FOR used in this proceeding is consistent with those of previous proceedings.

Q. Are there other assumptions PSE applies to the AURORA modeling of the Colstrip units?

A. Yes, the AURORA model uses several Colstrip-specific data inputs. In addition to the FOR input, PSE's AURORA model also includes: (1) the four-year average heat rate; (2) the average rate year coal heat content; and (3) the average transmission line losses on the Colstrip Transmission system (see Exhibit No. ___(MLJ-3C)). PSE also inputs the forecasted costs of coal from our coal supplier's Annual Operating Plans into the AURORA model. The annual variable cost per MWh for Colstrip is determined from these third-party estimates of coal costs and other fuel-related costs from PPL Montana's Business Plans, the average transmission losses and the average heat rate.

Q. What planned outages are included in the AURORA model to determine the rate year Colstrip fuel costs?

A. The AURORA model for this proceeding's rate year includes the actual outage schedules approved by Colstrip's owners. The rate year includes 80 days of planned unit outages for the combined Colstrip units. These 80 days are comprised of the full 55-day outage planned for the 2012 Unit 1 outage and 25 of the 44-days planned for the 2013 Unit 4 outage. Additionally, the AURORA model includes periods during the rate year when Units 1 and 2 will be derated to approximately two-thirds of rated capacity to allow for planned scrubber maintenance. PSE did not include rate year planned outages in the AURORA model for its 2009 GRC because there were no outages scheduled during that proceeding's rate year.

Q. Please describe other fuel-related costs.

A. The costs for lime used in the scrubbers and the cost of mercury control chemicals are included in AURORA to determine the cost of heat input. These costs are variable costs of production, rather than fixed, because they are directly related to the amount of energy produced.

The method of determining coal costs is unchanged from PSE's 2009 GRC: it is based on the Annual Operating Plans prepared by the mine owner, Western Energy Company. Coal costs are increasing due to increasing strip ratios (the amount of overburden that must be removed per ton of coal produced), as well as higher collective bargaining agreement wage rates and increases in diesel fuel costs, explosives costs and other commodities.[3] Royalties and production taxes, which are based on the direct cost of coal, add approximately 40 percent to the cost of coal purchased by PSE.

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[3] Such increases are consistent with least cost mine planning required by the coal supply agreements.

Q. How are the transmission losses determined?

A. Under the provisions of the Colstrip Transmission Agreement, the amount of power each owner receives is reduced to account for transmission line losses on the transmission lines from Colstrip to the junction with the Bonneville Power Administration ("BPA") lines near Townsend, Montana. Using data from PSE's energy management system, PSE compared the amount of energy received by PSE at the junction of Colstrip's transmission system and BPA's system with PSE's share of net generation at the power plant. The result showed that over the four-year period of January 2007 through December 2010, the losses averaged 2.96 percent.

IV. COLSTRIP PRODUCTION O&M

Q. Please describe the Colstrip legal settlements and insurance recoveries included in production operations and maintenance ("O&M") expense during this proceeding's test year (calendar year 2010).

A. The test year includes a credit of $2,429,480 for settlements and insurance recoveries related to three different Colstrip matters. The first matter is related to a 2008 accident (the Belmontez accident). PSE reached a settlement with Mr. Belmontez's estate in May 2010, and PSE's cost was [redacted]. PSE's insurance paid [redacted] and Mr. Belmontez's employer reimbursed [redacted]. The net test year cost to PSE for this matter was therefore [redacted].

In July 2010, PSE and plaintiffs settled litigation concerning Units 3 and 4's holding ponds (the Kluver litigation). PSE's share of this settlement totaled [redacted] [redacted] allocated to Units 1 and 2 and [redacted] to Units 3 and 4).

In November 2010, an agreement was reached concerning a partial reimbursement from former insurance carriers related to PSE's share of the settlement payment from the Ankney lawsuit in 2008. PSE's actual recovery totaled [redacted] ([redacted] was allocated to Units 1 and 2 and [redacted] was allocated to Units 3 and 4). This total was [redacted] more than the $2,083,590 credited for possible insurance recovery included in rates pursuant to PSE's 2009 GRC.

Q. What amount is included in the rate year production O&M for Colstrip lawsuit settlement costs?

A. The rate year production O&M includes a credit of $345,890 for settlement and insurance proceeds associated with the Colstrip units. PSE's 2009 GRC production O&M, which is currently being recovered in rates included an estimate of $2,083,590 for future insurance proceeds. Because the actual credit received for this lawsuit is included in this proceeding's test year, the $2,083,590 estimate currently in rates is appropriately removed from this proceeding's rate year production O&M. The rate year credit of $345,890 is the total test year credit of $2,429,480 less the $2,083,590 credit estimated in PSE's 2009 GRC.

Q. What are the sources of other operation and maintenance costs for Colstrip?

A. The operating and maintenance (O&M) costs for both jointly-owned facilities, the Colstrip units and Freddy 1, are developed from budgets and business plans provided by the plant operator and approved by owners. PSE has consistently used this practice in rate cases for determining rate year power costs.

Q. In your testimony in PSE's 2007 GRC, you described a coal supply agreement that included payment of a $5 million dedication fee. What accounting treatment did PSE apply to this dedication fee?

A. PSE recorded the payment as a prepaid asset and is amortizing it over nine years, 2011 through 2019.

Q. Please explain the rationale for the amortization of the dedication fee.

A. Starting at page three of my Prefiled Direct Testimony in Docket No. UE-072300, Exhibit No. MLJ-1CT, I discussed the Coal Purchase and Sale Agreement ("CPSA") between PSE, PPL and Western Energy Company ("WECo"). At the time of contract execution, PSE paid a $5 million dedication fee in order to obtain the exclusive rights to all of the uncommitted coal contained in Areas A, B and D of WECo's Rosebud Mine. However, this dedication of coal from these areas in the Rosebud Mine was limited by a prior contract executed by WECo and a third party, which terminated on December 31, 2010. In calendar year 2010 there was an overlap with WECo supplying coal for the CPSA and also supplying pursuant to this other contract. The appropriate amortization period for the dedication fee is one that matches the time period when customers will benefit from the lower cost of coal from the CPSA. This benefit period starts on January 1, 2011, and continues through December 31, 2019, the earliest date the CPSA can be terminated.

Q. Does that conclude your testimony?

A. Yes, it does.