Exhibit No.___(GND-1T)
Docket UE-11___
Witness: Gregory N. Duvall

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	
Complainant,	)	Docket UE-11______
vs.	)	
PACIFICORP dba Pacific Power & Light Company	)	
Respondent.	)	

PACIFICORP

DIRECT TESTIMONY OF GREGORY N. DUVALL

July 2011

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Gregory N. Duvall, my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present position is Director, Long-Range Planning and Net Power Costs.

Q. Describe your education and professional background.

A. I received a degree in Mathematics from University of Washington in 1976 and a Masters of Business Administration from University of Portland in 1979. I was first employed by PacifiCorp in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions and trading. From 1997 through 2000 I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. After returning to Portland, I was involved in direct access issues in Oregon and was responsible for directing the analytical effort for the Multi-State Process. Currently, I direct the work of the load forecasting group, the net power cost group, and the renewable compliance area.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I present the proposed pro forma normalized net power costs for the 12-month period ending May 31, 2013. Specifically, my testimony:

- Describes the primary drivers behind the increase in net power costs as well as factors that mitigate the increase;

- Describes the changes that the Company has made to comply with Order 06 in the Company's last general rate case in Docket UE-100749 (2010 Rate Case);[1]
- Presents the Company's 2011 Wind Integration Study (Wind Study), and explains how it is incorporated in the current filing, and
- Describes the modeling of net power costs under the west control area (WCA) allocation methodology.

Q. Is the Company proposing to contest any net power cost issues that were decided in the 2010 Rate Case?

A. No. Consistent with the make-whole rate filing approach, the Company has elected not to contest any issues that were decided in the 2010 Rate Case, including net power costs. The Company, however, reserves the right to contest these issues in the future as appropriate.

Summary of Net Power Cost Results in the Current Filing

Q. What are the proposed pro forma normalized net power costs for the test period?

A. The proposed pro forma normalized net power costs for the 12-months ending May 31, 2013, are approximately $567.5 million for the Company's west control area. As discussed in Company witness R. Bryce Dalley's direct testimony, the Washington-allocated net power costs are approximately $128.2 million prior to the application of the production factor adjustment.

[1] See *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-100749, Order 06 (March 25, 2011) (Order 06).

Q. How do the pro forma normalized net power costs in this proceeding compare to the net power costs authorized in the Company's 2010 Rate Case?

A. The pro forma normalized net power costs in the current proceeding are approximately $32.7 million higher than what was authorized by the Commission in the Company's 2010 Rate Case on a west control area basis, and approximately $7.0 million higher on a Washington-allocated basis. The $32.7 million increase in net power costs includes all Commission ordered adjustments and is consistent with the Company's make-whole filing.

Q. Please provide an illustration of the changes in net power costs since the 2010 Rate Case.

A. Table A, provided below, illustrates the change in net power costs by category:

Table A

	Washington 2011 GRC - Washington 2010 GRC		
Category	**Decreases in Net Power Costs ($ Millions)**	**Increases in Net Power Costs ($ Millions)**	**Change in MWh**
Total Special Sales For Resale		$10.7	(487,059)
Total Purchased Power		$43.4	667,037
Total Coal Fuel Burn Expense		$16.4	(175,025)
Total Gas Fuel Burn Expense	$21.1		(474,705)
Wheeling, Hydro and Other	$16.8		(205,220)
Net system Load			296,004
Total Net Power Costs	**$37.8**	**$70.5**	

The increase in net power costs is driven largely by an increase in purchased power, coal fuel burn expense and decreased revenues from special sales for resale. These increases in costs are partially offset by a decrease in natural gas fuel burn expense, wheeling and wind integration costs. Due to load growth, expiring low-cost contracts, continued low market prices, and the need to carry additional reserves on thermal generation, the Company realized less volume of wholesale sales and thermal generation and an increase in purchased power expense. The continued depression in market prices and the expiration of long term wholesale purchase contracts make it more economic at times to displace thermal units with purchases from the market.

Major Cost Drivers in the Pro Forma Test Period

Q. What are the primary drivers of the increase in net power costs since the 2010 Rate Case?

A. The increases in net power costs are primarily due to:

- Increases in market purchases to replace power lost due to the expiration of low-cost, long-term firm wholesale purchase power contracts;
- Increases in retail load and reduction in wholesale sales;
- Increases in coal costs; and
- Removal of the Condit hydro-electric facility.

These factors are partially offset by reductions in net power costs due to the expiration of wheeling contracts, and reduced output from natural gas-fired generation units.

Q. Please identify the long-term wholesale purchase power contracts that expire prior to the pro forma period.

A. The major wholesale purchase power contracts that expire prior to the pro forma period are:

- The Chelan Public Utility District (Chelan PUD) Rocky Reach project generation, expiring in October 2011;
- Grant Public Utility District (Grant PUD) Displacement generation, expiring in September 2011;

- Alcoa Power Generating Inc. (APGI) for approximately 100 megawatts (MW) of capacity from the Rocky Reach project, expiring in June 2011; and
- Bonneville Power Administration (BPA) for 575 MW of capacity, expiring in August 2011.

While these contracts were partially in effect in the 2010 Rate Case, they have been completely removed from the pro forma test period.

Q. Why do expiring wholesale purchase power contracts increase net power costs?

A. Wholesale purchase power contracts generally reflect wholesale electric market prices at the time they were executed. For example, the Chelan PUD contract has been in existence for approximately 50 years, and is priced at the embedded cost of the Rocky Reach hydro-electric project. The Grant PUD contract for displacement generation is priced at BPA's Priority Firm Power (PF) rate. The total impact of replacing the output of these two expiring contracts has the net effect of increasing net power costs by approximately $6.6 million on a west control area basis.

Further, both the arrangement with BPA for peaking products, an expiring 40- year contract, and the APGI contract for 100 MW of capacity, allowed the Company to receive energy during peak periods and return energy during off-peak periods, realizing value from taking power during high cost periods and returning it during low cost periods. In addition, the power received under the BPA capacity contract was delivered directly to a variety of the Company's load pockets in the west control area at the Company's discretion without incurring any additional wheeling expense. The Company must replace this energy and capacity with either its own generation resources or through wholesale power purchases.

Q. Does this filing reflect an increase in retail load that impacts net power costs?

A. Yes. At the same time the Company is losing existing resources, loads for the pro forma period are forecast to increase by approximately 290,000 MWh, or 1.4 percent in the west control area, as compared to loads reflected in the 2010 Rate Case for the twelve months ended March 31, 2012. All else held constant, increased load increases net power costs, which in this case increased net power costs by approximately $10.0 million.

Q. How does this increase in load discussed above reconcile with the statements in the direct testimony of Company witness Andrea L. Kelly regarding decreases in loads and retail revenues?

A. The comparisons relate to different time periods. The Company experienced a decrease in historic normalized sales when comparing calendar year 2009 to calendar year 2010. Historic loads are used for purposes of calculating test period revenues and allocation factors. For purposes of net power costs, the forecast loads in the 2010 Rate Case were for the 12 months ended March 31, 2012 and in this proceeding are for the 12 months ended May 31, 2013.

Q. Do the net power costs in this filing reflect increases in coal costs since the 2010 Rate Case?

A. Yes. Net power costs are higher by approximately $16.4 million as a result of increased coal prices that are partially offset by reduced generation at the Jim Bridger plant. The increased coal costs are addressed in detail in the direct testimony of Company witness Cindy A. Crane.

Q. Has the Company removed the Condit hydro-electric facility from the pro forma period?

A. Yes. The last day of generation from the Condit hydro-electric facility on the White Salmon River in southern Washington is currently targeted to be November 19, 2011. The Company has received all the necessary approvals to remove the Condit dam, provided a surrender order to the Federal Energy Regulatory Commission (FERC) and provided a notice to proceed to JR Merit who has been contracted by the Company to perform the dam removal.

Compliance with the Commission Ordered Adjustments

Q. Please describe how the Company reflected all Commission ordered adjustments in the current filing.

A. Consistent with the Company's make-whole filing, the net power costs for the pro forma period in the current filing have incorporated all the adjustments ordered by the Commission in Order 06 for the 2010 Rate Case:

- Removed temperature normalization of the commercial class;
- Added arbitrage margin based on a historical four-year average;
- Removed inter-hour wind integration costs for the wind projects located in the Company's west balancing authority area from which the company purchases nor of which the company owns;

- De-optimized the energy delivery of the sales contract with the Sacramento Municipal Utility District (SMUD) based on monthly delivery patterns of the four-year historical average;
- Imputed the outage rate of Colstrip 4 at 8.0 percent;
- Excluded expenses of the wheeling contract for access to the Direct Current (DC) Intertie;
- Removed half of the wheeling expenses under the contract with the Idaho Power Company for dynamic overlay services;
- Modeled sales to the east on an hourly basis;
- Prorated wheeling expenses for Colstrip 4 based on the transmission capacity from Colstrip to the west control area; instead of splitting equally between east and west;
- Excluded non-firm transmission capability and expenses; and
- Adjusted the heat rates and minimum generation levels of the thermal plants for outage derates.

Q. Please discuss the change in wheeling expenses from the Company's 2010 Rate Case.

A. Wheeling expenses are lower in the current pro forma period primarily due to the expiration of the Centralia point-to-point wheeling contract with BPA which the Company does not anticipate extending.

Q. What assumptions did the Company make in regard to the power rates and transmission rates proposed in the current BPA rate cases?

A. The BPA rate cases will determine the new rates for the fiscal period beginning in

October 2011. Given the current proposals made by BPA, the Company assumes that the wheeling expenses of the transmission contracts with BPA would not change in the new rate effective period beginning in October 2011. In this filing, the Company has incorporated the proposed wind integration charge at $1.32/kW-month beginning in October 2011, which is a change from the current $1.29/kW-month. The Company has also incorporated the impact of BPA's proposed charges for reserves and power.

Q. Does the Company expect to update the expenses related to all contracts with BPA?

A. Yes. The Company will update its net power costs on rebuttal with the final decision of the BPA rate cases currently expected in July 2011, or when better information becomes available.

Wind Integration Costs

Q. Please discuss the Company's approach to calculating wind integration costs?

A. As part of the 2011 integrated resource plan (2011 IRP, Appendix I), the Company performed an extensive Wind Study, included as Exhibit No.___(GND-2), on the impact of integrating wind generation into its resource portfolio. The Wind Study was completed after reviewing the issues and concerns raised by various parties in all of the Company's jurisdictions. Such issues include whether the wind integration costs should be studied independent of load, the amount of additional reserves needed to integrate the wind generation and what resources should be utilized to serve the additional reserve requirements.

Q. Please describe the Company's Wind Study.

A. The purpose of the Wind Study is twofold. First, the Wind Study quantifies how wind generation affects the amount of additional reserves needed to maintain reliability. Second, the Wind Study determines the costs of integrating wind generation by measuring how system costs change with changes in operating reserve demand, and by measuring how system costs are affected by daily system balancing practices.

Q. What are the additional reserve requirements?

A. The Wind Study identified additional regulation reserve requirements in two categories: regulating services that deal with load and wind variability in 10-minute intervals, and load following services that deal with load and wind variability over hourly time intervals. Both services respond to the up and down variations of wind generation. That is, the additional reserve requirements to integrate wind generation into the Company's resource portfolio consist of regulating up, regulating down, load following up and load following down. The Wind Study performed analyses of additional reserve requirements for load only (excluding wind generation) and for wind net of load (including wind generation), based on historical 10-minute data for the Company's system.

Q. How did the Company incorporate the results from the Wind Study in this filing?

A. The Wind Study does not address the impact of additional reserve requirement on the west control area in isolation. As a result, for this filing, the Company prorated the amount of additional reserve requirement to integrate wind in the west control area based on the amount of west side wind generation included in the Wind Study and the amount of wind generation in the pro forma period from the Marengo I and II projects and Combine Hills. Generation from non-owned wind projects in the west control area were not included.

Q. Did the Company implement the "must-run" operation identified in the Wind Study in order to accommodate the additional reserve requirements in the Generation and Regulation Initiatives Decision tools model (GRID) in the current proceeding?

A. No. The Wind Study does not address the impact of additional reserve requirements in the west control area in isolation and has not identified the need for "must-run" thermal resources in the west control area. The Company makes the assumption that the hydro-electric and thermal resources in the west control area are sufficient to deal with the rapid variations in wind generation.

Q. Does the Company believe that reflecting the additional reserve requirements in the GRID model, accurately reflects the costs of integrating wind into its system?

A. Yes. Allowing the GRID model to optimize the system, taking into consideration the additional reserves required to integrate the level of wind that is included in the GRID model, more accurately reflects the real-time operation of the system and the impact that current wholesale market prices have on the changes in system operation.

Q. Did the Wind Study also identify additional costs associated with day-ahead forecast errors for wind and load?

A. Yes. Using the results of the Wind Study, the Company modeled $0.70 and $1.21 per megawatt-hour for day-ahead forecast errors, or system balancing costs in the net power cost study for the months in 2012 and in 2013, respectively. These values are taken directly from Table 13 on page 33 of the Wind Study.

Q. Does the Company include system balancing costs for the non-owned wind projects and for projects located in the BPA's balancing authority area?

A. No. In compliance with Order 06, the pro forma net power costs in the current filing do not include system balancing costs for the wind projects located in the Company's west balancing authority area from which the company purchases nor of which the company owns. This is based on the assumption that the entities that own and/or operate those wind projects will balance their own system prior to handing over their generation schedule to the Company.

Q. Have wind integration costs decreased in the current filing as compared to the 2010 Rate Case?

A. Yes. Wind integration costs have decreased by approximately $4.7 million, from approximately $7.5 million to approximately $2.8 million for the west control area.

Determination and Modeling of Net Power Costs

Q. Please explain net power costs.

A. Net power costs are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale sales revenue.

Q. Please explain how the Company calculated pro forma net power costs for the 12-month period ending May 31, 2013.

A. Net power costs are calculated using GRID. For each hour in the pro forma period the model simulates the operation of the power supply of the Company.

Q. Is the Company's general approach to the calculation of net power costs using the GRID model the same in this case as in the 2010 Rate Case?

A. Yes. The Company uses the GRID model in this case consistent with the 2010 Rate Case, except a new release of the same version providing additional reports to address the thermal generating unit commitment logic issue. Because none of the general background on GRID has changed, instead of including GRID background testimony, I have attached that information to my testimony as Exhibit No.___(GND-3). As I discuss below, the Company has made some changes to the inputs to the GRID model.

GRID Model Inputs and Outputs

Q. Please describe any updated inputs to GRID.

A. The inputs to the GRID model have been updated to reflect the information available at the time the net power cost study was prepared for the current filing. This includes updates to the west control area load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas, fuel expenses, transmission capability, characteristics of the Company's generation facilities, and planned outages and forced outages of the Company's generation resources.

Q. What reports does the GRID model produce?

A. The major output from the GRID model is the net power cost report. This is attached to my testimony as Exhibit No.___(GND-4). Additional data with more detailed analyses are also available in hourly, daily, monthly and annual formats by heavy load hours and light load hours.

Determination of Net Power Costs on a West Control Area Basis

Q. How does the Company model net power costs for the west control area?

A. The Company modeled net power costs using the WCA allocation methodology adopted in Order 08, Docket UE-061546.[2] The Company has two control areas, east and west, with limited transfers between the two control areas. Under the WCA allocation methodology, only the load and resources in the west control area load are taken into consideration.

Q. What are the load obligations in the west control area?

A. The load in the west control area is composed of the retail load in the Company's service territories in the states of California, Oregon and Washington.

Q. What are the Company-owned resources in the west control area?

A. The Company-owned resources in the west control area include:

- Hydro resources – facilities on the North Umpqua River and Rogue River in Oregon, Lewis River in Washington, Klamath River in Oregon and California, and other small hydro facilities in the west control area;
- Wind resources – Leaning Juniper in Oregon, Goodnoe Hills, Marengo I and Marengo II in Washington; and

[2] See *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-061546, Order 08 (June 21, 2007).

- Thermal resources – Colstrip in Montana, Jim Bridger in Wyoming, Chehalis in Washington and Hermiston in Oregon.

The Colstrip and Jim Bridger plants are located outside the geographical area of the three western states. However, through owned and contracted transmission capabilities, the generation from the two plants is electrically interconnected with the Company's west control area.

The Company has shares in two units of the Colstrip plant. Because only Colstrip 4 is authorized by the Commission for rate setting purposes in Washington, only Colstrip 4 is included in the Washington-allocated net power cost. In addition, because there is a limitation on transmission capabilities, the generation from the Jim Bridger plant that can be wheeled into the west control area is approximately 96 percent of the total Jim Bridger capability. As such, the WCA allocation methodology only includes approximately 96 percent of the costs and output of Jim Bridger.

Q. Which wholesale purchase and sales contracts are included in the west control area?

A. The west control area net power costs include the Company's wholesale purchase contracts that have delivery points within the west control area, which include the contracts for the generation from the Mid-Columbia river hydro projects. Similarly, the wholesale sales contracts included all have delivery points in the Company's west control area.

Q. How are the Company's owned transmission capabilities and wheeling contracts treated under the WCA allocation methodology?

A. The Company-owned transmission capabilities and the rights from the wheeling contracts with third parties are included in the west control area modeling if they are used to transmit power from and to locations in the west control area.

Q. Is the west control area net power cost model constructed to include the load obligations, owned resources, wholesale contracts and transmission capabilities as described above?

A. Yes.

Q. Does this conclude your direct testimony?

A. Yes.