Exhibit No.___(GND-1T)
Docket No. UE-10___
Witness: Gregory N. Duvall

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PACIFICORP dba Pacific Power Respondent.	)))))))))))	Docket No. UE-10______

PACIFICORP

DIRECT TESTIMONY OF GREGORY N. DUVALL

May 2010

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 St., Suite 600, Portland, Oregon 97232. My present position is Director, Long-Range Planning and Net Power Costs.

Qualifications

Q. Briefly describe your educational 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 integrated resource planning group, 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 in this proceeding?

A. I present the proposed pro forma normalized net power costs for the twelve-month period ending March 31, 2012. In addition, my testimony:

- Describes the primary reasons for the increase in net power costs as well as factors that mitigate the increase;

- Describes the modeling of net power costs under the West Control Area (WCA) allocation method; and
- Describes the changes to modeling hydro generation in net power costs since the Company's last general rate case in Docket UE-090205 (2009 Rate Case).

Net Power Cost Results

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

A. The proposed pro forma normalized net power costs are approximately $569.9 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 $128.9 million prior to the application of the production factor adjustment.

Q. How do the pro forma normalized net power costs in this proceeding compare to the level in the 2009 Rate Case?

A. The pro forma normalized net power costs in the current proceeding are approximately $55.0 million higher than what was filed in the Company's 2009 Rate Case on a west control area basis, and approximately $17.5 million higher on a Washington-allocated basis. It is important to note that the 2009 Rate Case was settled without a specific finding on the level of net power costs or the components of net power costs.

Q. What are the primary factors driving the increase in net power costs since the 2009 Rate Case?

A. The factors with the largest impact include:

- Expiration of several long-term firm wholesale purchase power contracts;

- Expiration of the long-term gas supply contracts for the Hermiston gas-fired generating plant;
- Increases in firm wheeling expenses; and
- Increases in wind integration charges.

These factors are partially offset by reductions in net power costs associated with a lower load forecast, decreases in coal costs, lower market prices, and extended operation of the Condit dam.

Q. Do you have any general observations about the increase to net power costs in this filing?

A. Yes. As described later in my testimony, the pro forma period for net power costs in this proceeding marks the end of several low-cost wholesale purchase power, natural gas, and transmission contracts. PacifiCorp's customers have benefitted from these contracts for as long as 50 years. The expiration of these contracts is outside the control of the Company and creates a need to replace these contracts at current market prices.

Expiration of Wholesale Purchase Power Contracts

Q. Please discuss the major wholesale purchase power contracts expiring during the pro forma period of the twelve-months ending March 2012.

A. There are several expiring contracts related to wholesale purchases tied to Mid-Columbia hydroelectric projects. First, the contract between the Company and the Chelan Public Utility District (Chelan PUD) for generation from the Rocky Reach project expires in October 2011. This contract has been in existence for approximately 50 years, and is priced at the embedded cost of the project.

Second, the contract between the Company and the Grant Public Utility District (Grant PUD) for displacement generation expires in September 2011, and is priced at BPA's Priority Firm Power (PF) rate. Together with the reduction in revenues from the Reasonable Portion of the contract with Grant PUD due to lower market prices, the impact of the changes related to the Mid-Columbia purchase contracts increases net power costs by approximately $15.5 million on a west control area basis.

In addition, the exchange contract between the Company and Alcoa Power Generating Inc. (APGI) for approximately 100 megawatts of capacity from the Rocky Reach project expires in June 2011, and the contract between the Company and the Bonneville Power Administration (BPA) for 575 megawatts of capacity expires in August 2011. The arrangement with BPA for peaking products has been in existence for 40 years. Under both of these contracts, the Company receives energy during peak periods and returns energy during off-peak periods. The power received under the BPA capacity contract is delivered directly to a variety of the Company's load pockets in the west control area at the Company's discretion.

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. Given how long these expiring contracts have been in existence, wholesale electric market prices have increased since the contracts were executed and thus the cost of the replacement power has increased.

Expiration of Hermiston Gas-Supply Contracts

Q. Are there any major changes to the Company's fuel supply?

A. Yes. Beginning in July 2011, the long-term natural gas supply contracts for the Hermiston plant expire and are replaced by market purchases. Those long-term contracts were entered into in 1996, when the prices for natural gas were low. Even with escalation, the contract prices are still lower than the current market prices. That is, the final gas price of the long-term contracts through June 2011 is at $4.17 per million-British Thermal Unit (MMBtu), while the average gas price for the period from July 2011 to March 2012 is approximately $5.55 per MMBtu. The impact of the expiring Hermiston fuel contracts increases net power cost by approximately $40 million on a west control area basis for the owned and purchased portions combined.

Firm Wheeling Expense Increases

Q. What are the primary reasons for the increase in firm wheeling expenses?

A. One of the primary reasons for the increase in wheeling expenses is restructured wheeling contracts with BPA. After the low-priced formula power transfer (FPT) wheeling contracts with BPA expired, they were converted to higher-priced point-to-point (PTP) contracts. In this case, the Company's Coos-Curry wheeling contract with BPA, which was based on BPA's FPT rate, expires. This is a large, flexible wheeling contract that the Company has used to move power throughout the west control area for 45 years. BPA no longer offers the FPT rate, and requires that all new wheeling contracts be priced at their current PTP rate.

Wheeling expenses are also increasing due to the changes made by the

Idaho Power Company to modify the wheeling contract associated with delivering generation from the Jim Bridger plant to the Company's load areas in the west control area.

Finally, BPA's wind integration charge has increased significantly since the 2009 Rate Case. In the 2009 Rate Case, this charge was included in the wind integration charge category of net power costs at $0.68 per kilowatt-month (kW-month). The BPA wind integration charge is one of BPA's transmission charges and the Company books these charges to a wheeling account. In this filing, the BPA wind integration charge has been updated to $1.29 per kW-month based on the results of BPA's 2010-2011 transmission rate case. In the current filing, the Company is assuming that BPA's wind integration charge and wheeling rates will remain the same beyond BPA's current rate period that ends in October 2011. In total, these changes increase wheeling expense by approximately $8.7 million on a west control area basis.

Q. Has the Company's wind integration charge increased?

A. Yes. In addition to the increase to the BPA wind integration charge discussed above, wind integration charges for wind resources located in the Company's control area have also increased. For the wind resources located in the Company's control area, based on the Company's 2008 Integrated Resource Plan (IRP), the Company's wind integration costs have increased from $1.15 per megawatt-hour (MWh) in the 2009 Rate Case to approximately $6.97 per MWh. The total impact of the change in the Company's wind integration charge is approximately $7.9 million on a west control area basis. I will further discuss the wind integration charges later in my testimony.

Factors Offsetting Net Power Cost Increases

Q. Have coal costs decreased on a net basis from what was reflected in the 2009 Rate Case?

A. Yes. The costs at the Jim Bridger mine have decreased due to increased production and efficiency in the underground operation. This decrease is partially offset by increases in third-party coal contracts. The price of the contract with the Black Butte Coal Company to supply additional coal to the Jim Bridger plant has increased, which includes the impact of the new contract for a full year. The price of the contract with the Westmoreland Coal Company to supply coal to Colstrip unit 4 has also increased per terms of the contract. In total, the net reduction to net power costs associated with coal costs is approximately $3.3 million on a west control area basis.

Q. Has the Company assumed that the operation of the Condit dam will continue through the end of the test period?

A. Yes. The Condit dam on the White Salmon River in southern Washington is currently targeted to be decommissioned as soon as October 2011. Due to the uncertainty around obtaining various licenses in time to proceed in October 2011, the Company has assumed that the dam will be in operation through March 2012. If more definitive information is known during this proceeding, then the Company will revise net power costs accordingly in its rebuttal filing. If not, the Company reserves the right to apply for a deferral of the increase to net power costs that would result if the Company successfully obtains all the necessary permits and begins decommissioning the facility before March 31, 2012.

Q. Is the load in the pro forma period lower in this filing?

A. Yes. Compared with what was included in the Company's 2009 Rate Case, the load forecast in the west control area is lower by approximately 650,000 MWh, or approximately three percent. Holding everything else constant, lower load leads to lower market purchases, reduced generation or more sales to the market, all of which lower net power costs.

Q. Are there any other factors that offset the increases in the Company's net power costs?

A. Yes. The net power cost calculation in the current filing uses the Company's most recently available official forward price curve. This curve reflects lower forward prices than the curve used in filing the Company's 2009 Rate Case. Consistent with the Commission practice, the Company will update to the then-most recently available prices in its rebuttal filing.

Determination 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 twelve-month period ending March 31, 2012.

A. Net power costs are calculated using the Generation and Regulation Initiatives Decision tools model (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 2009 Rate Case?

A. Yes. The Company uses the GRID model in this case consistent with the 2009 Rate Case. 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-2). 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-3). 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. 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 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
- 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 west control area net power costs. 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 WCA net power cost model constructed to include the load obligations, owned resources, wholesale contracts and transmission capabilities as described above?

A. Yes.

Enhancements to the Hydro Modeling

Q. Please describe the enhancements to the hydro inputs the Company made in the filing.

A. There are two enhancements to the hydro inputs of the GRID model. The first enhancement is to apply single-year median hydro generation. The second enhancement is to explicitly model the reduced generation related to operating the hydro units for reserve purposes due to "motoring" and efficiency losses.

Q. How did the Company model normalized hydro generation in this proceeding?

A. The Company is proposing to use a single-year median water year developed based on the entire available history of the Company's hydro facilities, which range from 40 years to 90 years, instead of using the data from 40 individual water years.

Q. What is a "single-year median?"

A. The single-year median hydro input that the Company uses as the input to GRID in the current proceeding has one year normalized output from the Vista model, which is the same model that the Company has utilized in the prior filings to produce normalized hydro generation of the Company's hydro projects. A description of the model is also included in Exhibit No.___(GND-2) to my testimony. The inputs to Vista include median inflow volumes of the hydro projects from the available water inflow history. The inflow volumes are pro-rated daily or weekly based on weighting factors derived from corresponding median inflows. The annual volume of stream flows are based on a single year, hence the "single-year" reference.

Q. Please describe how the median hydro forecast is created.

A. For run-of-river projects, the single-year forecast is simply the median generation of the available historical data. For other river systems with reservoirs and the Mid-Columbia projects, the single-year inflow forecast is created based on the average daily or weekly shape and median annual volume of the available historical inflow data, which can range from about 40 years to about 90 years depending on the river system.

Q. Why did the Company make this enhancement to hydro modeling?

A. It is transparent and easy to understand and it is consistent with the hydro condition used by the Company for operational planning. The single-year median captures the most likely generation, rather than generation that may potentially be distorted by unlikely wet or dry years in the 40-water year history.

Q. Has the format of hydro generation data as inputs to GRID also changed?

A. Yes. GRID now takes the optimally shaped hourly hydro generation directly from the Vista model, rather than taking in weekly hydro generation and shaping it into hourly hydro generation in GRID.

Q. Does this significantly change the net power costs in the current filing?

A. No. The net power costs using the single-year median are lower by approximately $1.5 million on a west control area basis as compared to using the 40-water year hydro generation inputs.

Q. Does the single-year median hydro input improve the efficiency of modeling net power costs?

A. Yes. Using 40-water year hydro inputs requires 40 Vista runs and 40 GRID runs, consolidated into one single output for the pro forma period using simple averages. The multiple runs may not provide more and better information, but increase the complexity of the modeling and causes the run time to be unnecessarily long In contrast, the single-year median hydro requires only one Vista run and one GRID run. Given the alignment with the Company's operational practices, the increased transparency and simplicity, and the relatively small effect on Washington's revenue requirement, the Company believes that the use of the single-year median hydro for normalizing hydro generation is appropriate in this proceeding.

Q. Please explain the reduction in hydro generation due to motoring for spinning reserves.

A. In order to meet spinning reserve requirements, the Company must keep generating resources connected to the transmission grid and be responsive to automatic generation control. One option for providing spinning reserves is to "motor" a unit which means the unit is connected to the grid and spinning with electrical energy rather than with water. The Company motors units at both the Swift and Yale hydro projects located on the Lewis River in Washington. At the Swift project, the normal amount of energy required to motor a unit is approximately two megawatts. Motoring the unit with two megawatts of energy provides spinning reserve for the full range of unit output. To spin the unit at minimum load with water would require a flow through the turbine of approximately 350 cubic feet per second, which is extremely inefficient and would consume the equivalent of approximately 10 megawatts. Even though motoring consumes energy, it is more efficient and cost-effective than spinning a unit with water.

Q. What are the efficiency losses the Company proposes to capture in its hydro modeling?

A. To provide load following and system regulating requirements, the dispatchable hydro units at the Swift and Yale projects from time to time operate significantly below peak efficiency. However, the forecasted hydro generation data from the Vista model is optimized at peak efficiency. The cumulative effect of load following with hydro units is less efficient operations. In other words, less energy is generated with the same amount of water than would have been generated at peak efficiency.

Q. How does the Company adjust for the lost generation?

A. The lost generation from the Swift and Yale projects is deducted from its optimized generation. The amount of the adjustment is based on 2009 historical information.

Wind Integration Charges

Q. What has the Company included for wind integration charges in this filing?

A. As previously mentioned, there are two categories of wind integration charges, one for the Company's wind resources located in BPA's control area, and one for the wind resources located in Company's control area.

For the wind resources located in BPA's control area, the Company is relying on BPA's Record of Decision (ROD) on July 21, 2009 that set the wind integration charges to $1.29 per kW-month beginning in October 2009 for variations in the wind generation within 30 minutes. This charge is approximately $5.89 per MWh based on a 30 percent capacity factor for the wind resource and is an intra-hour wind integration charge only, because BPA does not perform inter-hour wind integration.

For the resources in the Company's control area, the Company has updated the wind integration charge to incorporate the latest information in the Company's 2008 IRP.

Q. Please explain the increase in the Company's wind integration charges.

A. As part of its 2008 IRP filed with the Commission on May 29, 2009, the Company performed studies of the impact of integrating the generation from wind projects into its system. Based on the same assumptions and methodology but using the data applicable to the pro forma test period, the Company calculated the costs incurred for wind integration as $6.97 per MWh, which is composed of $5.16 per MWh for intra-hour costs and $1.81 per MWh for inter-hour rebalancing costs. Appendix F to the Company's 2008 IRP, which is included as Exhibit No.__(GND-4), discusses the components of the Company's wind integration charges in further detail.

Q. Which wind plants are assessed the Company's wind integration charges?

A. All wind plants in the Company's west control area including non Company-owned wind plants, with the exception of Leaning Juniper and Goodnoe Hills, are assessed the Company's full wind integration charge. Leaning Juniper and Goodnoe Hills are in BPA's control area and are assessed the BPA intra-hour wind integration charge, plus the Company's inter-hour wind integration costs.

Q. Does the Company plan to update its wind integration charges during this proceeding?

A. Yes. In its IRP process, the Company agreed to update the wind integration study by August 2, 2010, addressing comments from parties to the IRP process. The Company will update its wind integration charges when the outcome from the wind integration study is available.

Q. Does this conclude your direct testimony?

A. Yes.