Q. Please state your name, business address and present position with Rocky Mountain Power (the Company), a division of PacifiCorp.

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

Qualifications

Q. Please briefly describe your education and business experience.

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 Pacific Power 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, was responsible for directing the analytical effort for the Multi-State Process (“MSP”), and currently direct the work of the integrated resource planning group, the load forecasting group, the forward pricing group, and the net power cost group in the Company.

Summary of Testimony

Q. Will you please summarize your testimony?

A. I present the Company’s proposed net power costs for the 12-month period ending June 2009. Specifically, my testimony:

- Describes the primary drivers of the increase in the Company’s net power costs, and

- Sponsors as a confidential exhibit the GRID model Net Power Cost report that supports this filing.

Net Power Cost Results

Q. What are the proposed normalized net power costs?

A. The normalized net power costs for the twelve months ending June 2009 are approximately $469.6 million on a Utah allocated basis, or $1.129 billion system-wide. The Company's net power cost study is provided as Confidential Exhibit No. RMP___(GND-1). The allocation of total Company net power costs to Utah is presented in Exhibit No. RMP___(SRM-2) in Mr. Steven R. McDougal's testimony.

Q. How do these compare with the net power costs the Company presented in Docket 07-035-93, the Company's last general rate case?

A. Docket 07-035-93 is now under advisement for Commission decision. The Company's final testimony in that docket supported system net power costs of $1.046 billion, but actually requested system net power costs of $1.044 billion. This forecast was for the twelve months ending December 2008, based on the Company's March 31, 2008 Official Forward Price Curve. The proposed system net power costs in this case, using the June 30, 2008 Official Forward Price Curve and forecasting forward an additional six months, are about $85 million higher.

Primary Drivers of Increase in Net Variable Power Costs

Q. Please describe the environment for net power costs now facing the Company.

A. As I testified in Docket 07-035-93, the Company's system net power costs are increasing sharply at a rate of $40 to $50 million every six months. The Company's forward price curve for the 12-month test period in the current proceeding is more than 20 percent higher than the one for the 12-month period in Docket 07-035-93. The Company has not experienced rising net power costs of this magnitude since the Western energy crisis.

Q. Are these cost increases reflected in the Company's most recent actual net power costs?

A. Yes. The Company's actual system power costs for the twelve-month period ending May 31, 2008 were approximately $1.055 billion. The Company's actual system power costs for calendar year 2007 were $975 million. Thus, in just five months, the Company actual system net power costs increased by approximately $80 million. The Company's historical actual system net power costs now exceed the forecast net power costs the Company requested in Docket 07-035-93.

Q. Is the Company's experience regarding increased net power costs unique or transitory?

A. No. At its meeting on June 19, 2008, the FERC discussed the causes and potential duration of rising electricity costs. The presentation by the analysts from FERC's Office of Enforcement stated "that forward market prices for electric power are much higher than the prices we actually experienced last year. This trend is universal around the country." It also showed that the forward prices for July and August of 2008 were significantly higher than last years, and indicated that "[t]here is little reason to believe that this summer is unusual. Rather, it may be the beginning of significantly higher power prices that will last for years."

Q. What are the primary drivers of the increase in net power costs?

A. In general, besides higher electric prices, the largest factors causing the cost increase are higher retail loads, higher coal prices and higher natural gas costs. These increases are mitigated by the addition of new resources and the operation of Company hedges.

Q. How does increased retail load impact the Company's proposed net power costs?

A. This filing reflects a system-wide increase in load of 0.8 million megawatt hours (1.4 percent) when compared to total company loads included in Docket 07-035-93. All things being equal, additional retail load will require the Company to re-dispatch the system utilizing additional higher cost thermal resources and by making additional market purchases and reduced market sales.

Q. Please explain the Company's coal fuel price increases.

A. The coal price increases at our generation facilities are being driven by a variety of factors, including increases in commodity costs (oil, steel and gas), the impact of contract re-openers, and higher mine operating costs.

Q. Can you give examples of these cost increases?

A. Yes. The cost increase of fuel supplied by the Arch coal purchase is mainly due to a price re-opener as well as contract escalation. The cost increase at the Jim Bridger mine is mainly due to increased depreciation and depletion associated with the underground mining operations, increased royalty costs, as well as increased labor, benefits and overall operating costs. The cost increase at the

Deer Creek mine is caused by a combination of increased costs in materials and supplies coupled with increased labor, benefits, insurance and royalties.

Q. Please explain the sources of the increase in the Company's gas costs.

A. Gas prices have generally trended upward over the last several years and the Company expects this trend to continue through 2009. Many gas utilities have recently proposed double-digit increases to rates caused by increasing gas pass-through costs. The Company's gas costs reflect market prices, plus cost increases or decreases to reflect Company's hedged position. In this case, the Company forecast gas costs are increasing at less than market rates, due to the Company's gas hedges.

Q. Are the cost increases partially offset by the inclusion of the near zero variable costs from renewable energy facilities expected to be in service during the test period?

A. Yes. The net power costs include expected generation from the 39-megawatt Glenrock III, 99-megawatt Rolling Hills, and 19.5-megawatt Seven Mile Hill II wind projects that are all located in Wyoming and expected to be in service in December 2008, and the 99-megawatt High Plains wind project that is also located in Wyoming and expected to be in service in June 2009. The proposed net power costs also include a full year operation of the 94-megawatt Goodnoe wind project located in Oregon, the 140-megawatt upgraded to the 210-megawatt Marengo wind project located in Washington, and the 99-megawatt Seven Mile Hill wind project located in Wyoming. Because the Company owns these wind facilities, the variable cost of these resources is close to zero, except a projected

$1.14 per megawatt hour charge for intra-hour integration of wind generation into the Company's resource portfolio.

Q. Does the proposed net power costs include the impact of the Chehalis plant?

A. Yes. The proposed net power costs include generation from the Chehalis plant that is located in Washington, which is currently under a tolling agreement. The Company has also entered into a contract to acquire the plant and the transaction is expected to close in September 2008. Further details on the Chehalis plant are provided in the testimony of Rob Lasich. The Company's variable net power costs are lower because of the generation from the Chehalis plant.

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 calculates net power costs.

A. Net power costs are calculated using the GRID model. For each hour in the test period, the model simulates the operation of the power supply portion of the Company under three stream flow conditions. The results obtained from the stream flow conditions are averaged and the appropriate cost data is applied to determine an expected net power cost under normal stream flow and weather conditions for the test period.

Q. Are these proposed net power costs developed with the same production dispatch model used in Docket 07-035-93?

A. Yes, the proposed net power costs are developed using version 6.2 of the GRID model.

Q. Do the proposed net power costs in this case reflect certain GRID modeling changes that the Company agreed to in Docket 07-035-93?

A. Yes. In Docket 07-035-93, the Company agreed to address the impact of the GRID model's uneconomic commitment of certain gas units by calculating the value of alternating nighttime screens of these units, offset by the costs of increased unit start-ups. In the calculation of net power costs for the current proceeding (Docket 08-035-38), the Company applied this same approach to Currant Creek and Lake Side plants. A four-hour midnight screen was also applied to the Chehalis plant. Additionally, the Company removed the costs of uneconomic dispatch of the call options in any month included in net power costs calculation.

Q. Have you made other adjustments to net power costs agreed to in Docket 07-035-93?

A. Yes. Consistent with the Alternative 2 position stated in my rebuttal testimony, the Company has applied a normalized maintenance schedule with no outages scheduled during the summer and winter months, applied annual forced outages without weekly or monthly modeling, and removed the ramping adjustment for any gas units.

Q. Similar to Docket 07-035-93, does the Company propose to update its filing in its rebuttal testimony for material changes in net power costs, such as new contracts, fuel costs and the Official Forward Price Curve, irrespective of whether these changes increase or decrease net power costs?

A. Yes. This ensures that the Commission has the most accurate and current information available to it in setting rates for the test period.

GRID Model Inputs and Outputs

Q. Please explain the inputs that go into the model.

A. Inputs used in GRID include retail loads, thermal plant data, hydroelectric generation data, wind plant generation data, firm wholesale sales, firm wholesale purchases, firm wheeling expenses, system balancing wholesale sales and purchase market data, and transmission constraints.

Q. Please describe the retail load that is used in the model.

A. The retail load represents the forecast hourly firm retail load that the Company expects to serve within all of its jurisdictions for the twelve-month period ending June 30, 2009.

Q. Please describe the thermal plant inputs.

A. To determine the amount of energy available, the Company averages for each unit four years of historical outage rates and maintenance. The heat rate for each unit is determined by using a four-year average of historical burn rate data. By using four-year averages to calculate outages, maintenance and heat rate data, annual fluctuations in unit operation and performance are smoothed. For this filing, the 48-month period ending December 2007 is used. Other thermal plant data includes unit capacity, minimum generation level, minimum up/down time, fuel cost, and startup cost.

Q. Are there any exceptions to the four-year average calculation?

A. Yes. Some plants have not been in service for the entire four-year period. For those plants, the Company uses the manufacturer's expected value for the missing months to produce a weighted average value of the known and theoretical rates.

Q. Please describe the hydroelectric generation input data.

A. The Company uses the output from the VISTA hydro regulation model for GRID's hydroelectric generation input data. The Company uses three sets of expected generation from VISTA, which is the same as in Docket 07-035-93.

Q. Does the Company use other hydro generation inputs?

A. Yes. Other parameters for the hydro generation logic include maximum capability, minimum run requirements, ramping restrictions, shaping capability, and reserve carrying capability of the projects.

Q. **Please describe the wind generation input data.**

A. The Company uses wind site information from the project developers to estimate generation, or use historical patterns when they become available.

Q. Please describe the input data for firm wholesale sales and purchases.

A. The data for firm wholesale sales and purchases are based on contracts to which the Company is a party. Each contract specifies the basis for quantity and price. The long-term firm contracts are modeled individually, and the short-term firm contracts are grouped based on general delivery points. The short-term firm contracts with flexibility are modeled individually so that they are optimized from the point of view of the holder of the call/put.

Q. Please describe the input data for wheeling expenses and transmission capability.

A. Firm wheeling expense is based on the wheeling expense for the twelve-month historic period ending December 2007, adjusted for known contract changes in the forecast period through twelve-months ending June 30 2009. Firm transmission rights between transmission areas in the GRID topology are based on the Company's Merchant Function contracts with the Company's Transmission Function and contracts with other parties. The limited additional transmission to which the Company may have access is based on the experience of the Company's commercial and trading department. An example would be the day ahead firm transmission that the Company historically purchases on Path "C."

Q. Please describe the system balancing wholesale sales and purchase input assumptions.

A. The GRID model uses five market points to balance and optimize the system. The four established wholesale markets are at Mid-C, COB, Four Corners, and PV. The Mona market has also been incorporated to reflect the level of transactions the Company enters at this limited market. Subject to the constraints of the system and the economics of potential transactions, the model makes both system balancing sales and purchases at these markets. The input data regarding wholesale markets include market price and market size.

Q. What market prices are used in the net power cost calculation?

A. As noted above, the market prices for the system balancing wholesale sales and purchases at four liquid markets are from the Company's June 30, 2008 Official Forward Price, shaped into hourly prices. While the Mona market prices were developed consistent with the Company's June 30, 2008 price curves, they are not part of the official curve due to the limited nature of the market and are highly confidential. The market price hourly scalars are developed by the Company's commercial and trading department based on rolling five-year historical hourly data. The hourly prices for the test period are then calculated as the product of the scalar for the hour and the corresponding monthly price.

Q. What reports does the study produce using the GRID model?

A. The major output from the GRID model is the net power cost report. Additional data with more detailed analyses are also available in hourly, daily, monthly and annual formats by heavy load hours and light load hours.

Q. Do you believe that the GRID model appropriately reflects the Company's system operations in its operating environment?

A. Yes. The use of the GRID model as described in my testimony, coupled with the refinements proposed in Docket 07-035-93, appropriately simulates the operation of the Company's system over a variety of streamflow conditions consistent with the Company's operation of the system including operating constraints and requirements.

Q. Does this conclude your direct testimony?

A. Yes.