Q. Please state your name, business address and present position with PacifiCorp, dba Rocky Mountain Power ("Company").

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

Qualifications

Q. 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 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 ("MSP"). 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.

Summary of Testimony

Q. Will you please summarize your testimony?

A. I present the Company's proposed net power costs ("NPC") for the test period of 12-months ending June 2012. The first section of my testimony explains the test period NPC increase and describes the major cost drivers underlying the increase. I also review how the Company has modeled NPC in this case.

Additionally, in the last case in which NPC was fully litigated, the Company's 2009 general rate case, Docket No. 09-035-23 ("2009 GRC"), the Commission's order ("2009 Rate Case Order") directed the Company to provide additional information and analysis on certain issues. The second section of my testimony addresses these issues. On several major issues, including market caps and wind integration, I explain how the Company has refined and developed its modeling approaches since the 2009 GRC.

Summary of Net Power Costs in the Current Filing

Q. What are the forecasted normalized system-wide NPC for the 12-month period ending June 2012?

A. The Company's total forecasted normalized system-wide NPC for the test period of 12-months ending June 30, 2012, are approximately $1.521 billion on a total Company basis, and $649.1 million on Utah allocated basis.

Q. Please compare NPC forecasted in this case to NPC now in rates.

A. NPC on a total Company basis as authorized by the Commission in the Company's 2010 second major plant addition case ("MPA 2 Case"), Docket No. 10-035-89, are approximately $994.2 million. The Company's forecast net power costs in this case are higher by approximately $527.1 million on a total Company basis.

Q. How does the test period NPC in the current case compare with the actual NPC?

A. For the 12-month period ended June 30, 2010, which is the test period in the MPA 2 Case, the Company's actual NPC are approximately $1,064.2 million, or $70.0

million higher than normalized NPC from that case. The most recent 12-month actual NPC through November 2010 are $1,172.3 million or $178.1 million higher than normalized NPC from the MPA 2 Case. Actual NPC illustrates the escalation of NPC since the MPA 2 Case, which reflected one of the lowest NPC levels of the last several years.

Q. Please generally describe the drivers of the increased NPC reflected in this filing.

A. The increase in NPC is driven by three main factors: load growth, increases in coal costs, and the reduction in wholesale sales revenue for the test period. NPC in this case also reflects many changes in the Company's portfolio of resources. Each of these factors is described below.

Major Cost Drivers in the Forecast Test Period NPC

Q. How does the retail load forecast impact the Company's NPC?

A. This filing reflects an increase of approximately 3.4 million megawatt-hours, or 5.9 percent, in the total Company load forecast compared to loads in the 2009 GRC (which were also the basis of NPC in the MPA 2 Case). All else held constant, increased load increases NPC. In this case, load growth increased NPC by approximately $109 million. For further details on the load forecast, please refer to the testimony of Company witness Dr. Peter C. Eelkema.

Q. Have the Company's coal costs impacted the NPC in the current proceeding?

A. Yes. NPC are higher due to increases in the costs of third-party coal supply and transportation agreements, and cost increases at the Company's captive mines. Approximately one-third of the NPC increase in this case is attributable to coal costs. This issue is addressed in detail in the direct testimony of Company witness Ms. Cindy A. Crane.

Q. How does the reduction in wholesale sales revenue impact the NPC in the current filing? Please explain.

A. The wholesale sales revenues in the current filing are lower than what are in the MPA 2 case, which increases NPC in the current filing. The drop in wholesale sales revenues is mainly caused by the changes in the Company's load and resource balances. As stated above, the Company's system load is approximately 3.4 million megawatt-hours higher. In addition, due to expiration of long term contracts, the Company's purchased power under the long term contracts is approximately 1.6 million megawatt-hours lower. That is, the Company has lost approximately 5.0 million megawatt-hours of resources that could be sold to the wholesale market because of just these two changes. The 91 percent drop from over 5 million megawatt-hours to less than 0.5 million megawatt-hours in the short term firm sales is reflective of such an impact.

Q. What are the major changes to the long term firm power contracts in the test period of 12-months ending June 2012?

A. The contracts with changes in the test period include:

- On October 1, 2010, the purchase contract between the Company and the Top of the World Wind Energy, LLC went in effect. This contract and the procurement process are described in the direct testimony of Company witness Mr. Stefan A. Bird.
- On January 1, 2011, the amount of sales to the Public Service Company of

Colorado ("PSCol") reduced per the contract terms, and then expires on December 31, 2011. The contract is a legacy sales contract at relatively high contract prices.

- On June 30, 2011, the exchange contract between the Company and the Alcoa Power Generating Inc. ("APGI") for approximately 100 megawatts of capacity from the Rocky Reach project expires. Under this contract, the Company receives capacity during peak periods and returns energy during off-peak periods.
- On August 31, 2011, the contract between the Company and the Bonneville Power Administration ("BPA") for 575 megawatts of capacity expires. Under this contract, the Company receives energy during peak periods and returns energy during off-peak periods. In addition, power received under this contract is delivered directly to a variety of the Company's load pockets in the western area at the Company's discretion.
- On September 30, 2011, the contract between the Company and the Grant Public Utility District ("Grant PUD") for displacement generation expires, which is priced at BPA's Priority Firm Power ("PF") rate.
- On October 31, 2011, the contract between the Company and the Chelan Public Utility District ("Chelan PUD") for generation from the Rocky Reach project expires. Power purchased by the Company under this contract is priced at the embedded cost of the project.
- On December 31, 2011, the contract between the Company and the Biomass One qualifying facility expires, which was in effect since 1987 and at then

relatively high prices for purchases from qualifying facilities.

Q. Has the Company made assumptions about the power rates and transmission rates proposed in the current rate cases of BPA?

A. Yes. The BPA rate cases are to 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 that the Company has with BPA would not change in the new rate effective period beginning in October 2011. In the current 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 proposal in 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 NPC on rebuttal with the final decision of the BPA rate cases, or when better information becomes available.

Q. Has the Company included in the current filing a retail interruptible contract that expires prior to the test period?

A. Yes. The current contract between the Company and Monsanto for operating reserve purchases expired at the end of 2010. The price of this contract is currently under review by the Idaho Public Utilities Commission in the Company general rate case. In this filing, the terms of the existing contract are assumed to continue. The Company will update to the terms of the new contract when available. The Company expects the Idaho Public Utilities Commission to rule on this issue in February 2011.

Q. Does the Company model the impact of capital additions from the Company's two major plant addition cases in 2010, Docket Nos. 10-035-13 and 10-035-89?

A. Yes. In this filing, the Company has incorporated the impact of Dave Johnston unit 3 scrubber, the Populus to Terminal transmission line, and the Dunlap wind facility.

Modeling of NPC and Model Inputs and Outputs

Q. Please explain NPC.

A. NPC 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 NPC.

A. NPC are calculated for a future test period based on projected data using the Generation and Regulation Initiative Decision ("GRID") model. GRID is a production cost model that simulates the operation of the Company's power system on an hourly basis.

Q. Is the Company's general approach to the calculation of NPC using the GRID model the same in this case as in previous cases?

A. Yes. The Company has used the GRID model to determine NPC in its filings for several years.

Q. Is the Company using the same version of the GRID model as used in its 2009 GRC and MPA 2 Case?

A. Yes, except a new release of the same version providing additional reports to address the thermal generating unit commitment logic issue.

Q. What inputs were updated for this filing?

A. All input data have been updated since the 2009 GRC and MPA 2 Case, which include system load, wholesale sales and purchase contracts for electricity, natural gas and wheeling, market prices for electricity and natural gas, fuel expenses, characteristics and availability of the Company's generation facilities.

Q. Has the Company changed its topology modeled in GRID?

A. Yes. To assure the reliability of the transmission network in the area governed by the Western Electricity Coordinating Council ("WECC"), the constraint in the cut plane named Tot 4A in Wyoming has been redefined by PacifiCorp Transmission and approved by WECC. As a result, the previously modeled transmission areas of "Wyoming NE" and "Wyoming SW" in GRID have been redefined. In addition, because of constraints that are present in the previous "Wyoming SW" transmission area, a "Trona" transmission area has been added to the topology to reflect such constraints.

In addition, the Company proposed a different modeling of non-firm transmission, which I will address later in my testimony.

Q. What reports does the GRID model produce?

A. The major output from the GRID model is the NPC report. This is attached to my testimony as Exhibit RMP___(GND-1). 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 forecasted net power costs over the test period?

A. Yes. The GRID model reasonably simulates the operation of the Company's system load and resource portfolio consistent with the Company's operation of its system including operating constraints and requirements. GRID produces a reasonable forecast based on "static" assumptions that are different from actuals for the same period.

Issues Identified in the 2009 Rate Case Order

Q. Pursuant to the 2009 Rate Case Order, is the Company providing further information and analysis on specific NPC issues?

A. Yes. In the 2009 Rate Case Order, the Commission requested that the Company address certain NPC issues in its next full NPC filing. Pursuant to this directive, my testimony addresses the following issues, which are listed in Paragraph III.B.3 of the 2009 Rate Case Order:

1. GRID Market Capacity Limits
2. Uneconomic Modeled Operation
3. Start-up Fuel Energy Value
4. Chehalis Start-up Costs
5. Short-Term Firm (STF) Transmission Test Year Synchronization
6. Transmission Imbalance

7. Wind Integration Charge
8. Stateline and Long Hollow Wind Integration Costs
9. Minimum Loading Deration and Heat Rate Modeling

1. GRID Market Capacity Limits

Q. As a part of approving the Company's market caps in the 2009 GRC, did the Commission request updated support for the caps in the future?

A. Yes. At page 27 of the 2009 Rate Case Order, the Commission stated that "(w)e will, in this case, accept the Company's use of the market caps but will require updated support in the future to determine if these caps continue to be relevant and if they are not resulting in unintended and inappropriate consequences with respect to forecasting STF sales in graveyard hours."

Q. How did the Company model the market capacity limits in GRID in the 2009 GRC and previous cases?

A. The GRID model assumes unlimited market depth for system balancing sales and purchases. To reflect the illiquidity of the four major wholesale sales markets, Mid-Columbia ("Mid C"), California Oregon Border ("COB"), Four Corners, and Palo Verde ("PV") during graveyard hours and in all hours for the illiquid market hub of Mona, the Company modeled caps on market depth. The Commission first recognized the need for market caps in Docket No. 03-035-14, Order (Oct. 31, 2005) (approving the Company's use of market caps when calculating avoided costs).

Q. Has the Company refined its modeling of the limits on market depth for the wholesale sales markets in GRID in the current filing?

A. Yes. After the 2009 GRC, the Company reviewed its approach to market caps and developed a more accurate and comprehensive approach to modeling market depth. Instead of specifying market depth for graveyard hours only, the Company now proposes to specify market depth during all hours, segregated by heavy-load-hour ("HLH") and light-load-hour ("LLH") periods. The Company believes that a market may be liquid, but this liquidity does not translate into unlimited sales at any time of day or night. Due to load requirements and transmission constraints in the region and static assumptions about market prices in GRID, among other things, the Company may not be able to sell all its economic generation to the markets.

Q. How has the Company determined the market depths it uses as an input to GRID?

A. The market depths for wholesale sales in GRID are determined based on the historical short term firm transactions during the same 48-month period on which availability of the thermal generation is based. The depths are then reduced by the quantity of short term firm transactions that the Company has included in the normalized NPC study for the test period in all sales markets.

Q. What is the impact of this change in methodology?

A. The new methodology allows GRID to make more sales in the graveyard hours, but limits sales at some other times. A study using data from the 2009 GRC shows that the net impact of the change in modeling methodology is an increase in NPC of less than $1 million on a total Company basis.

Q. Have you compared the coal generation in GRID using the new market caps against the historical coal generation?

A. Yes. In that study using data from the 2009 GRC, the coal generation during the LLH increased by approximately 550,000 megawatt-hours with the new market caps compared with the study using the graveyard-hour caps from the 2009 GRC. The HLH coal generation is 140,000 megawatt-hours lower than what was modeled previously. As compared with the actual coal generation in the historical period used as the basis in the 2009 GRC, the coal generation in that study is higher in both HLH and LLH periods. Thus, based on the data from the 2009 GRC, the new caps (1) continued to allow GRID to model more than actual coal generation, proving that they do not unduly constrain the markets; and (2) allowed GRID to reflect more coal generation on a net basis than the old market caps.

2. Uneconomic Modeled Operation

Q. How did the 2009 Rate Case Order address the commitment logic screens?

A. On pages 29-30 of the 2009 Rate Case Order, the Commission adopted the daily screening method proposed by the Office of Consumer Services ("OCS") and, in future cases, directed the Company to provide certain information requested by OCS to facilitate modeling of the screens.

Q. Has the Company adopted daily screens?

A. Yes. The Company has refined the daily screens ordered in the 2009 GRC, and developed a set of more effective daily screens as inputs to GRID. The Company models all the gas units to run starting at the beginning of the test period, and then uses daily screens to turn them off if they are not economical to run. Once all other inputs have been set, final NPC are determined after a series of GRID runs to screen out the uneconomic commitment of gas-fired plants. The screens are set in a manner that prevents the gas-fired plants from being committed to run if they displace less expensive resources taking into consideration start-up costs and other operational constraints of starting up and shutting down gas units.

Q. Has the Company modified the outputs from GRID to provide more information to facilitate such screens?

A. Yes. The Company has implemented a new release of GRID that has a new report consolidating several individual reports necessary for the screening process, as requested by OCS and directed by the Commission.

3. Start-Up Fuel Energy Value

Q. How did the Commission decide the issue of the value of start-up energy in the 2009 Rate Case Order?

A. The Commission stated on page 34 of its 2009 Rate Case Order that "(w)e will accept the Company's explanation in this case and make no adjustment to value start-up energy. However, in the future the Company must demonstrate quantitatively that the value associated with GRID model simplifications offsets the value of start-up energy."

Q. Why does the Company believe that it is inappropriate to model the value of start-up energy in GRID?

A. Start-up costs are not limited to fuel. In order to accommodate the start-up of a 500 to 600-megawatt gas unit, the Company must re-dispatch the system. In doing so, the Company incurs costs beyond what it would have incurred had the start-up not occurred. These costs could result from ramping down the lower-cost hydro and thermal units to lower efficiency levels, and increasing generation from higher-cost units prior to when they are needed. None of these costs are included in GRID. In addition, if start-up energy is to be considered, the multi-hour start-up sequence must also be considered. The end result is that the units would need to stay offline and be unavailable for a longer time in order for the adjustment for start-up energy to be applicable.

Q. Did the Company perform a study to quantify one of the aspects mentioned above -- extending minimum down time of the units?

A. Yes. Extending the minimum down time for those gas-fired units in GRID and using the same methodology proposed by the Division of Public Utilities ("DPU"), the system NPC increases by approximately $0.6 million.

Q. Is the impact of increasing NPC limited to the value stated above?

A. No. As discussed above, extending the minimum down time is only one of the aspects that need to be considered in modeling the start-up energy of the gas-fired units. Incorporating the other aspects in NPC, (e.g., less efficient operation of hydro and thermal units) would increase NPC further.

4. Chehalis Start-up Costs

Q. How did the Commission rule on the issue of Chehalis start-up costs?

A. The Commission stated on page 39 of its 2009 Rate Case Order that "(a)s the Chehalis plant has limited operational data, we will accept use of the Currant Creek derived data for this case as a reasonable proxy at this time. In the next power cost case, we direct the Company to provide documentation supporting any Chehalis start-up assumptions and to provide a detailed explanation comparing these assumptions to those used in the Chehalis approval proceeding, Docket No. 08-035-35."

Q. Does the Company continue to use the same assumption for the Chehalis start-up costs, which is based on data from Currant Creek?

A. Yes.

Q. Please explain.

A. The Currant Creek and Chehalis facilities are both 2x1 configured combined cycle plants which burn natural gas as their fuel. Both plants use two General Electric 7241FA combustion turbine generators and one conventional steam turbine. The gas turbines at both plants are connected to heat recovery steam generators, which take the combustion turbine exhaust gas and use it to convert water into steam as in a conventional boiler. The steam is then passed through conventional steam turbines to generate additional electrical energy. At both plants, the exhaust steam from each of the steam turbines is passed through an air-cooled condenser where it is condensed back to water and reused in the heat recovery steam generator. Total nominal output is approximately 540 megawatts at Currant Creek, which includes 105 megawatts of duct firing capability and 520 megawatts at Chehalis.

The major factor contributing to the differences in the combined cycle capability is that the Currant Creek plant is sited at 5,051 feet elevation and Chehalis plant is located at 230 feet of elevation. At Chehalis, inlet air cooling is achieved with a spray mist fog cooling system, whereas the Currant Creek facility utilizes evaporative cooling. Other than elevation differences, the only material difference between the plants are that the Currant Creek plant has approximately 105 megawatts of duct-firing capability whereas the Chehalis plant has no duct firing capability.

Operational similarities exist as well between Currant Creek and Chehalis. The full time staffing at both plants is comparable with 18 full time equivalents at Currant Creek and 19 full-time equivalents at Chehalis. The largest plant operating costs, excluding fuel and labor, at each facility are the costs to maintain the combustion turbines. General Electric provides this service at both facilities under long-term contractual service agreements. The Company renegotiated both long-term contractual service agreements in 2009 to take advantage of having multiple, like-kind combustion turbines. The two facilities now share major combustion turbine parts needed for performing planned combustion turbine overhauls.

Based on the similarities in configuration, operation and maintenance described above, the Company believes it is appropriate to assume that both plants will have the same start-up cost.

Q. Is this start-up cost different from what the Company assumed in Docket No. 08-035-35? Please explain.

A. Yes. The Chehalis start-up costs assumed in Docket No. 08-035-35 were based on the tolling agreement for operating the Chehalis plant with Suez energy Marketing NA, Inc., which was the best information available to the Company at the time and appropriate for the purposes of evaluating the initial plant acquisition. However, the start-up costs as specified in the tolling agreement were not comparable to the start-up costs used in GRID for determining whether to commit the plant to run. For the purposes in Docket No. 08-035-35, there were other fixed and variable O&M costs applied in the studies, which included the impact of the starting up the plant. For purposes of modeling the Chehalis plant in GRID, proxy data based on Currant Creek's start-up costs is more accurate than the information from the tolling agreement.

5. STF Transmission Test Year Synchronization

Q. What did the Commission request the Company to provide in its 2009 Rate Case Order?

A. On page 42 of its order, the Commission accepted the Company's modeling of STF transmission, but directed the Company to explain several issues related to modeling of STF and non-firm ("NF") transmission in GRID, including the reason why the wheeling expenses are not modeled the same as wheeling revenues and outside the model and what the distinctions are between the two types of transmission.

Q. How did the Company model STF and NF transmission in the Company's 2009 GRC?

A. The availability of STF transmission was modeled based on the historical four-year averages, and the expenses of the STF transmission was based on the most recent actual STF wheeling expenses. The availability and variable expenses of the NF transmission were both based on the historical four-year averages.

Q. Has the Company made any changes to its modeling of NF transmission in the current filing and why?

A. Yes. The Company has included the NF transmission in the current filing in the same manner as STF transmission, both the capability and expenses.

Q. Please explain why the Company now treats the NF transmission the same as the STF transmission.

A. In the process of reviewing how the Company has utilized NF transmission, it is clear that the Company purchases and uses STF and NF transmission in the same way. The transmission providers offer certain amounts of transmission capacity as firm products, and the rest as non-firm. The only difference between the two products is that NF transmission will be cut for reliability purposes first. The Company purchases NF transmission in the same way as the STF transmission, so the expenses are incurred whether the amount of transmission capacity purchased is fully utilized each hour or not. As a result, the Company has combined the STF and NF transmission, and modeled all the short term transmission capability based on four-year average of the historical purchases of transmission, and the expenses in the base period of the current filing.

Q. Why does the Company use the four-year average for availability and the most recent year of data for costs in modeling short term transmission?

A. The volume of the short term transmission varies from year to year. The Company uses four-year average availability to smooth such variation and to estimate the amount of transmission that would reasonably be available in the test period, and uses the most recent year of expense to capture the most recent costs associated with acquiring transmission services from third-party transmission providers whose tariff rates could update periodically.

Q. Since short term wheeling expenses do not vary with the energy transferred through those transmission paths, why doesn't the Company model the expenses outside the model?

A. The Company could capture the wheeling expenses outside the GRID model. However, consistent with how the other costs are treated in GRID that do not vary with amount of energy delivered, such as the capacity payments of wholesale power contracts and reservation charges of the pipelines for delivery of natural gas, the Company elected to capture the wheeling expenses in GRID.

Q. Why does the Company treat wheeling expenses differently from wheeling revenues?

A. Wheeling expenses and wheeling revenues are caused by different activities. Wheeling expenses are incurred by the Company's merchant function to serve its retail load obligations, and to make off-system wholesale sales, and are paid to third parties for the rights to use their transmission facilities. In contrast, wheeling revenues are received by the Company's transmission function to operate its owned transmission facilities, and are paid by third parties who requested the rights to wheel power on those facilities.

6. Transmission Imbalance

Q. What did the Commission direct the Company to address related to the transmission imbalances?

A. In accepting the Company's modeling of transmission imbalances, on page 44 of the 2009 Rate Case Order, the Commission stated that"(w)e note two factors raised by the Company that will need to be addressed in the next case addressing power costs. The first is the assumption of no intra-hour markets for power. We understand this issue is evolving and direct the Company to explain how the existence of such a market will impact the transmission imbalance issue. Second, we direct the Company to explain and demonstrate that basing the imbalance energy tariff on the market price index is better for retail rate payers than incremental and decremental generation price."

Q. What is the requirement placed on the Company in providing imbalance services as a balancing area authority?

A. Under the Company's Open Access Transmission Tariff ("OATT"), the Company is obligated by the Federal Energy Regulatory Commission ("FERC") to provide imbalance service for wholesale transmission customers consistent with Schedules 4 and 9 of the OATT.

Q. What is the Company's expectation of how intra-hour markets for power would impact the services that it provides for handling transmission imbalances as a balancing area authority?

A. The existence of intra-hour markets and intra-hour scheduling is expected to reduce the differences between scheduled and actual generation during the hour. Under current scheduling practices, a customer must schedule generation as final at 20 minutes to the hour and any deviations as a result of actual generation amounts during the subsequent hour create imbalance. A joint initiative group in the western interconnection is working to develop common business practices that will allow schedule adjustments at the half hour. The Company's transmission business practice #48, which is posted on the Company's Open Access Same-Time Information System ("OASIS") website, currently allows limited non-firm intra-hour schedules. Unfortunately, until such time as most balancing authorities in the west provide for similar practices, an intra-hour market will not be available. At the present time, there virtually are no intra-hour markets in the Company's balancing areas. Recently, FERC issued a Notice of Proposed Rulemaking ("NOPR" or the "Proposed Rule") on integration of variable energy resources that I will discuss in more detail below, in which FERC proposes that public utility transmission providers should provide more frequent transmission scheduling intervals, so that transmission customers can adjust their transmission schedules or submit new schedules intra-hour to reflect, in advance of real-time, more accurate generation profiles. Implementation of 15-minute scheduling will provide transmission customers increased opportunities to adjust schedules and better manage imbalances, specifically those caused by variable resources such as wind generation. The Company is actively exploring the proposals in the NOPR and will provide comments to FERC by March 2, 2011.

Q. Would the existence of intra-hour markets change how the Company models transmission imbalances in GRID?

A. No. For normalization purposes, the Company assumes transmission schedules and actual transfers will match, meaning it is not necessary to provide imbalance services to transmission customers.

Q. How does the Company charge for imbalance services?

A. The service and associated charges for transmission imbalances are part of the Company's OATT as described in Schedules 4 and 9, which define imbalance charges according to a tiered market price structure. If the Company is making up a customer's energy shortfall, the energy provided to the customer will be at the defined market price as if the Company were to procure the needed energy for that hour from another seller.

Conversely, if the Company is paying a customer for any energy surplus, the defined price will be what the Company could sell that surplus into the market. Over time, the imbalance and the associated payments are expected to balance. The tiered approach in Schedules 4 and 9 is established by the FERC as an incentive for transmission customers to properly schedule resources to load and to limit imbalance costs.

Q. Why does the Company use market indexes to price the transmission imbalances?

A. The resources that the Company uses to provide imbalance service represent the lost opportunity for the Company to make or avoid market sales or purchases when the service is required by transmission customers. In addition, using market indexes to price the imbalance is a transparent mechanism that the Company can use to recover from or pay to customers using the service. Imbalance charges or payments can create billing disputes with customers if the pricing mechanism isn't clear and transparent or has any hint of subjectivity by the Company. A transparent mechanism eliminates billing disputes and challenges associated with service charges.

Q. Please explain why the Company believes that incremental and decremental pricing is not transparent and can lead to disputes.

A. The Company operates its resource portfolio to serve all its obligations, and does not differentiate between resources used for meeting its various load obligations. Furthermore, in order to determine the incremental and decremental generation prices, the Company would need to identify the costs of the resource(s) dispatched for the last incremental obligation, which would require considerations of various factors in the dispatch of the resources, including incremental fuel and O&M of the owned resources, operational requirements of the generating units, contractual requirements of the fuel supply for the units, and dispatchability of contracted resources. As a result, the Company believes that FERC-approved OATT pricing for imbalance service based on market indexes are reasonable.

7. Wind Integration Charge

Q. How did the Commission decide the issue of wind integration costs in the 2009 Rate Case Order?

A. On pages 49-50 of the Order, the Commission approved the Company's wind integration charge of $6.62 per megawatt-hour, but directed the Company "to enhance its wind integration methodology" to address the issues raised by other parties in the 2009 GRC.

Q. Has the Company enhanced its wind integration methodology since its 2009 GRC?

A. Yes. As part of the 2011 Integrated Resource Plan ("IRP"), the Company performed an extensive study on the impact of integrating wind generation into its resource portfolio ("Wind Study")[1]. The Wind Study was created after reviewing the issues and concerns raised by various parties in Utah and other jurisdictions, such as whether the wind integration costs should be studies 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. Could you briefly describe the Company's Wind Study?

A. Yes. 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 reserve requirements in two categories: regulating services that deal with load and wind variability in ten-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 regulation up,

[1] The Wind Study can be found on the Company's website at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp_2010WindIntegrationStudy_090110.pdf.

regulation 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. Besides providing regulating services and load following services, what other costs are incurred to integrate the wind generation?

A. Given the size of the wind portfolio, and the possibility of rapid variations in wind generation from the forecast displayed in the historical actual operation, the Company expects that it will need to continue committing its gas units to be able to quickly respond to the magnitude of changes. At times, this "must-run" operation would require gas units to run when it would otherwise be uneconomic to do so, therefore adding to the wind integration costs.

Q. What are the costs identified by the Wind Study?

A. The Wind Study shows that the costs of integrating wind generation into the Company's resource portfolio (regulation and load following services, system balancing and the requirement of must-run) for the three-year period from 2011 to 2013 are $9.70 per megawatt-hour at the wind generation penetration level of 1,833 megawatt, which is the level of wind currently in the Company's balancing areas.

Q. How did the Company apply the results from the Wind Study?

A. Instead of applying the dollar per megawatt-hour charge to the wind generation, the Company updated the amount of load following requirement as modeled by GRID to capture the impact of regulation up and load following up, both of which are identified in the Wind Study. The assumption is that if the resources are sufficient to serve the regulation up and load following up, they may be sufficient to serve the regulation down and load following down. The amount of the total load following requirements is based on the wind penetration level at 1,833 megawatts, which are 337 average megawatts and 196 average megawatts for the east and west sides of the Company's system, respectively. In addition, as identified in the Wind Study, the Company also modeled the Currant Creek unit, and Gadsby units 4, 5 and 6 as must-run units that are not subject to the logic of being committed to run only when economic. The result of this approach is an analytically enhanced wind integration charge that is, as reflected in GRID for the current filing, approximately equal to the charge previously approved by the Commission.

Q. How much is included in NPC for system balancing costs which are incurred as a result of day-ahead forecast errors for wind and load?

A. The Company modeled $0.71 per megawatt-hour for system balancing costs, which is the 2011-2012 average of system balancing costs as indentified in the Wind Study.

Q. Do you believe that the Company reasonably modeled the Wind Study results in GRID for the current filing?

A. Yes. Given the complexity of the subject, I believe that the result from GRID has reasonably reflected the impact of integrating wind generation into the Company's portfolio. In addition, the Wind Study has addressed all the issues raised by DPU, Utah Association of Energy Users ("UAE") and OCS in the

Company's 2009 GRC, such as reserve requirements being modeled within GRID, the requirements for wind generation being considered net of load, and the quality of data used to prepare the study. However, given the limitation of data inputs to the normalized studies, I believe that the GRID modeled impact of integrating wind resources may understate the real costs. For example, the GRID model uses expected wind profiles of the wind projects which lack the variability reflected in the actual operations of the wind projects.

Q. What does the Company include as the system balancing costs for the non-owned wind projects, and the overall wind integration costs for projects located in the BPA's balancing area?

A. The forecast NPC in the current filing do not include system balancing costs for the wind projects located in the Company's balancing areas that the Company neither owns nor purchases the output 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 that balances the variations within the hour as the balancing area authority. Following the same logic, the forecast NPC includes system balancing costs for projects located in BPA's balancing area: Leaning Juniper and Goodnoe Hills.

8. Stateline and Long Hollow Wind Integration Costs

Q. How did the Commission address the issue related to third party wind projects?

A. Stateline and Long Hollow are two wind projects located in the Company's balancing authority areas, but the Company does not receive their output. They require transmission and ancillary services provided under the Company's OATT. The OATT does not contain an explicit charge for integrating wind resources, so the Company cannot charge these costs directly to third party projects. On page 51 of its order, the Commission allowed third party wind integration charges but directed "the Company to address this issue prior to its next rate request to avoid the risk of a cost disallowance."

Q. Does the Company plan to raise this issue in its next FERC rate case?

A. Yes. The Company plans to file a rate case with FERC no later than June 1, 2011, in which the Company will include updated charges for ancillary services needed to integrate wind, pending any FERC guidance on the issue.

Q. Has there been any guidance from FERC in this matter since the Company made the plan? If so, please describe.

A. Yes, on November 18, 2010, the FERC issued a Notice of Proposed Rulemaking ("NOPR" or the "Proposed Rule") on integration of variable energy resources, such as wind. In general, the NOPR proposes that public utility transmission providers implement operational and scheduling changes to help integrate wind, including 15-minute intra-hourly transmission scheduling and power production forecasting using meteorological and operational data. FERC also proposes to add an ancillary service rate schedule through which public utility transmission providers will offer regulation service to transmission customers delivering energy from a generator located within the transmission provider's balancing authority area.

Q. Would the Proposed Rule allow the Company to charge non-owned wind generators the cost of integrating their generation into the transmission system, and how?

A. Yes. If the proposals in the NOPR remain unchanged and pending any additional guidance from FERC, the Company should be able to propose an ancillary service rate for regulation service to transmission customers delivering energy from a generator located within the Company's balancing authority area, which would include wind. As required by the Federal Power Act, this charge would have to be applied on a non-discriminatory basis. Currently, the OATT does not permit public utility transmission providers to charge generators for regulation service unless the generator is a transmission customer who also serves load in the balancing area.

Q. Does the Company believe that this new wholesale ancillary service charge, if approved by FERC, helps recover the costs of integrating wind? Please explain.

A. Yes. Regulation service is a type of energy reserve service necessary for integrating resources into the transmission system. Regulating reserves account for the variability of load and generation on the transmission system on a moment-to-moment basis. If the NOPR proposals remain unchanged and are approved as part of a final rule, the new charge would apply to resources when they are exporting to load in other balancing authority areas and would result in additional revenues from non-owned resources that are not delivering power to serve the Company's native load.

Q. Did FERC provide additional guidance in the NOPR on what it proposes to require before it will allow public utility transmission providers to impose a charge that collects a different volume of regulating reserves from variable energy resources? If so, please describe.

A. Yes. In the NOPR, FERC states that to the extent a public utility transmission provider proposes to impose a charge on variable energy resources for a different volume of generator regulation reserves than it proposes to charge transmission customers delivering energy from other generating resources, such differing volumes must be shown to be commensurate with the variability that the resources exhibit on the transmission provider's system and the transmission provider must show that it has implemented the other operational and scheduling reforms proposed in the NOPR. The transmission provider must have implemented the new tools for at least one year prior to filing any such proposal.

Q. Does the Company believe the NOPR proposals support its plans to include a proposed charge in its transmission tariff rates as part of its June 2011 transmission rate case?

A. Yes, the Company believes the FERC NOPR provides important guidance and direction on what the Company must do to address this issue. It is reasonable to assume the NOPR will become a final rule. As such, the Company believes the NOPR lays out the path to follow to begin charging non-owned facilities for the costs incurred to integrate them into the Company's balancing areas. The Company also believes, pending any additional guidance from FERC on this issue, that it can include a proposal for a new regulation service charge as part of the transmission rate case filing and that such a proposal has a higher chance of being accepted because of this recent guidance. If and when approved by FERC, such a charge will increase revenues that can be used to offset costs in the Company's retail revenue requirement calculations.

Q. What are the benefits to the Company's customers of providing such services to the non-owned generation?

A. As a balancing area authority, the Company owns and operates an extensive transmission network that it is required to operate safely and reliably for all of its customers, keeping all resources and loads in balance on a moment-to-moment basis. In addition, the Company is mandated to make its transmission network available to all generators in an open access and non discriminatory fashion. By providing wind integration services in addition to other transmission related services as a balancing authority, the Company ensures that its customers are served by a reliable system, with diverse resources. Moreover, any transmission revenues received from non-owned generation, which pays wheeling to the Company, are credited against retail revenue requirement and therefore have the effect of lowering the cost of service for retail customers.

9. Minimum Loading Deration and Heat Rate Modeling

Q. What did the Commission order regarding whether and how the heat rate curves of the thermal units should be adjusted for the impact of derates?

A. The Commission accepted the Company's modeling of this issue, but opined that the issue warranted further investigation. On page 57 of the 2009 Rate Case

Order, the Commission stated that“(w)e direct the Company, Division and other interested parties to review alternatives for addressing this issue, review actual operations in comparison to modeling predictions, and to understand the extent of the issue.”

Q. Were there any discussions on the subject since the conclusion of the Company’s 2009 GRC?

A. Yes. DPU organized a meeting on September 8, 2010. The Company participated in the discussion at the meeting, along with members of DPU and OCS, and their consultants.

Q. Were the issues resolved at the meeting?

A. No. Both the Company and OCS were requested to provide further analyses related to the impact of heat rate because of deration. Because the Company and OCS’s consultant were litigating this issue in another state, neither the Company nor OCS offered further analyses, and the issues were not resolved.

Q. How does the Company respond to the Commission’s example of “proportionally adjusting or compressing the heat rate curves so when a plant is running at its full derated capacity it will have a heat rate associated with the non-derated full capacity?”

A. The Company does not believe such adjustment is necessary or warranted, because the heat rate at derated capacity is still at a relatively efficient level. In actual operations, a unit can be derated to any level between its minimum and maximum capacities where the units can be significantly less efficient.

Q. Does this conclude your direct testimony?

A. Yes.