Q. Are you the same Gregory N. Duvall who has previously testified in this proceeding?

A. Yes. I filed direct testimony in this case.

Purpose of Testimony

Q. What is the purpose of your supplemental testimony?

A. I present the Company's supplemental net power costs that are adjusted based on the Commission Order in Docket No. 07-035-93.

Q. What are the proposed normalized net power costs in this supplemental filing?

A. The normalized net power costs for the twelve months ending June 2009 are approximately $461 million on a Utah allocated basis, or $1.109 billion system-wide. The Company's net power cost study is provided as Confidential Exhibit No. RMP___(GND-1S). The allocation of total Company net power costs to Utah is presented in Exhibit No. RMP___(SRM-2S) in Mr. McDougal's supplemental testimony.

Q. What has changed since the Company's filing on July 17, 2008?

A. Based on the Commission Order on August 11, 2008 in Docket No. 07-035-93, the Company has identified three categories of adjustments to its July filing, and updated its net power costs accordingly. The list of specific changes is provided as Exhibit No. RMP___(GND-2S). My testimony below provides additional detail on these changes.

Q. Please briefly describe the three categories of changes.

A. The first category of adjustments includes the ones that either have already been included in the Company's July filing or made in this supplemental filing, such as revised dispatch of the gas plants and prices of the Sunnyside qualifying facility contract. This category also includes the adjustments that are made based on the Company's most recent available data, such as Hermiston losses and Currant Creek outage rate. These were described in my direct testimony.

The second category of adjustments includes the ones that the Commission ordered but the Company has not made in this supplemental filing either because they are no longer applicable, such as revised dispatch of West Valley units, or because the Company continues to support its original position in this case. For adjustments such as the modeling and pricing of the wholesale power sales contract between the Company and the Sacramento Municipal Utility District ("SMUD") the Company requests that, based on the evidence presented in this case, the Commission revisit the adjustments in this case.

The third category of adjustments are for updated information since the Company's filing in July, which include modeling the wind integration charge proposed by the Bonneville Power Administration ("BPA") for the generation from Leaning Juniper and Goodnoe Hills, updated short term firm extracts, and coal costs.

<u>Category Two Adjustments</u>

SMUD Contract

Q. What is your recommendation on the pricing of the SMUD contract?

A. I recommend the Commission make a *price* imputation of $37 / MWh for the SMUD contract consistent with the orders in PacifiCorp's 1999 and 2001 general rate cases.

Q. Why is your recommendation different than the treatment ordered by the Commission in Docket No. 07-035-93?

A. In the 1999 rate case, the Commission approved an imputed price of $37 per MWh. In reaching that conclusion, the Commission was clear that an imputation decision (which is essentially the same thing as a prudence decision) "should be made *in light of circumstances existing at the time*. This view continues to be appropriate and we will apply it in this Docket. Since the contract was below-market when signed, the task before us is to find the rate, *contemporaneous with the date of the contract*, to use as the basis for revenue imputation."[1] The Commission accepted the $37 per MWh price from the SCE contract as a proxy for the price that would have been prudent under the SMUD contract.[2] In the revenue requirement order in the 2001 rate case (Docket No. 01-035-01), the Commission reaffirmed the $37 per MWh imputed price.[3] In Docket No. 07-035-93, the Commission set an imputed price of $58.46 per MWh, effectively converting the original imputed *price* of $37 per MWh into an imputed *revenue*

[1] *Re PacifiCorp*, Utah PSC Docket No. 99-035-10, 201 P.U.R. 467, 498 (May 24, 2000). (emphasis added).

[2] Coincidentally, the $15.46 per MWh imputed revenue resulting from the SCE contract price was also a fair approximation of taking the $94 million upfront payment and amortizing it over the life of the contract. *See* Exhibit DPU-SR, Dalton Surrebuttal/3, l. 41-4, l. 44.

[3] In the revenue requirement order in 2001 rate case, the Commission erroneously left the door open for an increase in the imputation level and thus backed off from its unequivocal 1999 ruling that its role in an imputation issues was to determine the proper amount *as of the date of the contract*. Although this language in the 2001 ruling was incorrect, it was not appealable by the Company because the Company was not harmed by the "dicta," and the issue was not ripe.

adjustment of $37 per MWh, to which the Commission then added the current contract price of $21.46 per MWh. Whether this outcome was the result of a calculation error or was an intentional change in the Commission's approach to the SMUD contract, the result was unsupported by the record and by applicable law and precedent.

Q. Was the theory of the SMUD pricing analysis used by the Commission in Docket No. 07-035-93 correct?

A. No. the underlying theory of the analysis adopted by the Commission—which is that the imputed price of $37 per MWh was designed to impute revenues at a level tied to return the $94 million lump sum payment to customers—is incorrect. A review of the Commission's earlier orders on the SMUD contract demonstrates that the Commission set the imputed price for the contract at a level that approximated market prices at the time of the contract. While the $94 million lump sum payment may have supported the Commission's decision to impute a higher than actual price to the contract, the imputed price was never explained to be tied to "cashing out" the lump sum payment.

Q. Do you have any additional support for your recommendation on the pricing of the SMUD contract?

A. Yes. The Commission has long recognized that the prudence of a utility decision is to be judged based on the facts and circumstances known or that should reasonably have been known to the utility at the time it made its decision. It is inappropriate to judge the decision based on hindsight or new information. When the Commission reviewed the SMUD pricing issue in 1999 and determined that an imputed price of $37 per MWh was appropriate, it necessarily determined that based on information known to or that should have been known to the Company when it entered into the SMUD contract in 1987, $37 per MWh was the appropriate imputed price. That imputation cannot change based on new information or circumstances in 2008 that could not have been known to the utility in 1987 when it entered into the SMUD contract. Accordingly, increasing the imputation violates the well-established prudence standard. Finally, taking into consideration new information or circumstances to increase the SMUD imputation and decrease the Company's net power costs also results in asymmetrical ratemaking. The Commission has not considered new information or circumstances demonstrating the increased value to customers of various other Company contracts, such as the BPA peaking contract or the Hermiston gas contract.

Q. What is your recommended method to normalize the SMUD contract energy?

A. I recommend the use of GRID to normalize the SMUD contract energy which is the method used to normalize the output of other purchase and sales contracts.

Q. Why are you recommending a normalization method that differs from that ordered by the Commission in Docket No. 07-035-93?

A. The GRID normalization method optimizes the output of purchase and sales contracts against market prices. I believe this is the preferable method to normalize contracts.

Q. How did the Commission normalize the output of the SMUD contract in Docket No. 07-035-93?

A. The Commission used four years of history to "normalize" the output of the SMUD contract.

Q. Does the Company oppose the use of four years of history to normalize the SMUD contract output?

A. Yes, if that is the only contract that is normalized using that method. It may well be that using four years of history is an acceptable methodology for normalizing the output of the SMUD contract, but if indeed it is an acceptable methodology it should be consistently applied. If the technique is accurate, then the same technique should be applied to analyze all similar contracts. The point here is quite simple: it is unfair and inconsistent to arbitrarily pick one large third-party contract from a much larger group of third-party contracts and treat it for regulatory purposes differently than all others are treated.

Transmission Imbalances

Q. Why doesn't the Company make an adjustment for transmission imbalances?

A. The Company understands that the Commission ordered this adjustment because "(t)he Company does not rebut the inclusion of transmission imbalance charge" in its testimonies. In response to the Commission's order, the Company provides the following evidence that there is no need for an adjustment because costs and revenues are already matched.

Q. What are transmission imbalances?

A. Transmission imbalances refer to the deviation of scheduled generation and actual generation. Because the Company is the control area operator, it is responsible to balance the load and resources within the control area at any given time. The amount of energy actually generated by the third party generators often does not match what they schedule. When this occurs, the Company is required to supply power to meet shortages or absorb surplus generation.

Q. How are other parties charged or paid for the imbalances?

A. Based on the FERC tariff, if the deviation is within one percent, the Company is paid or pays the market prices, depending on whether the Company needs to deliver or receive power for the differences between scheduled and actual generation. If the deviation is beyond a set percentage, the Company is paid with a percent of "premium" or pays a percent of "discount" from the market prices, depending on the directions of the differences. When the deviation caused by non-intermittent generators becomes even bigger, the "premium" and "discount" becomes bigger.

Q. Doesn't that mean the Company receives the benefits from such "premiums" and "discounts"?

A. No. When the Company pays other parties or gets paid by other parties for imbalances, it is only to compensate the Company for the cost incurred in providing the imbalance service. The imbalance occurs within-the-hour, where there is no market for transactions to cover such imbalances. In addition, the amount of energy purchased or sold, or even whether it is a purchase or a sale, is not known to the Company until after the hour when power schedules and actual generation can be compared to determine if the Company received or supplied power. As the result, the Company has to either back-down its own low-cost generation or have additional generation available to cover the load. The "premium" or "discount" is intended to be an incentive for the third parties to minimize the imbalances, rather than a benefit or economic gain to the Company, which is the underlying assumption in the methodology ordered by the Commission in Docket No. 07-035-93. In addition, consistent with the perfect foresight assumed in GRID, there are no transmission imbalances in its normalized modeling, which is also the same reason that the Company does not model the payments to BPA for imbalances caused by scheduling the generation from the Leaning Juniper and Goodnoe Hills facilities through BPA's system.

Biomass

Q. Why doesn't the Company make an adjustment for the Biomass non-generation agreement?

A. The Company currently does not have a contract with Biomass for non-generation. An agreement was entered into with Biomass prior to the rebuttal phase of Docket No. 07-035-93, but the agreement does not have an annual non-generation provision. The calculation of a non-generation adjustment would be dependant on both the incremental price of hog fuel and the market price of power. Neither party has any material control over the prices, nor is there any reasonable correlation between the price of hog fuel and the market price of power. Therefore, it is neither known nor measurable as to the frequency and amount of non-generation adjustments..

Category Three Adjustments

Wind Integration

Q. Please explain what changes the Company has made to the wind integration charges for Leaning Juniper and Goodnoe Hills.

A. BPA has proposed to charge for wind integration beginning October, 2008. Because the Company's Leaning Juniper and Goodnoe Hills wind facilities are interconnected to BPA's transmission system, the Company is expected to incur such expenses for these two projects.

Q. Has the Company updated the reserve requirement modeling for the Leaning Juniper wind facility?

A. Yes. The GRID study no longer includes reserve requirements for Leaning Juniper because BPA provides the reserves for the facility. The charge for these reserves is included in the wheeling expenses. This adjustment lowers net power costs.

Coal Costs

Q. Why are the coal costs updated?

A. The coal costs have been updated to reflect the most recent information. Coal costs have increased by approximately $12.9 million; costs for the captive mine operations increased by $13.8 million and contract costs decreased by approximately $0.9 million. The plants served by the captive mine operations reflect updated mine plans prepared in August 2008. The reduction in contract costs is primarily due to lower diesel fuel costs.

Other Changes

Q. Are there any other changes since the July filing and included in the third category of changes?

A. Yes. As the result of including the Commission ordered adjustments, it is no longer necessary to screen the Chehalis plant. Therefore, the night screen for the Chehalis has been removed. And also, because the GRID model does not capture the startup costs of the gas-fired units that are not included in any other FERC accounts, a line item is added to the net power cost report to capture the startup fuel costs of the gas-fired units, together with the adjustments made for the O&M costs associated with the additional startups required to screen the gas-fired units.

Forward Price Curve

Q. Have you made updates to the official forward prices curve?

A. No. The forward price curve that is used in this supplemental filing remains the Company's June 30, 2008 Official Forward Price Curve which is the most recent Official Forward Price Curve available at the time of the supplemental filing.

Q. What prices are included in the Company's official forward price curve?

A. The official forward price curve contains monthly prices for both wholesale electricity and natural gas. The electricity price curves are produced for both on-peak and off-peak delivery patterns and for various delivery points, including Mid-Columbia, California-Oregon-Border, Palo Verde, northern California (NP15), and southern California (SP15). The natural gas price curves include burner-tip prices for gas delivered to the Company's gas-fired plants along with prices at various delivery points throughout the west, including Opal, Sumas, Stanfield, and southern California.

Q. How is the official forward price curve developed?

A. The official forward price curve is typically updated each quarter and is comprised of three primary components. (1) The first 72 months of the curve reflect electricity and natural gas market forward prices as of a given quote date. For example, the June 30, 2008 official forward price curve used for the current proceeding reflects market forwards as of June 30, 2008. The market forwards used in the official forward price curve are validated against broker quotes for that trading day. (2) Months 73 through 84 of the official forward price curve are a blend of the previous year month-on-month market forwards and the following year month-on-month fundamentals forecast. (3) Beyond month 84, the forward price curve is developed from a fundamentals-driven price projection. The fundamentals portion of the curve is based upon an external natural gas price forecast. The Company uses the external natural gas price projection and other fundamental inputs to develop a consistent electricity price forecast.

Q. Which component of the forward price curve is used in this case?

A. Only the first component, market quotes, is used in this filing given the timing of the test period.

Q. Does the Commission use the Company's forward price curves for other purposes?

A. Yes. The Commission has employed the Company's forward price curves in rate case proceedings, integrated resource planning, resource acquisition analysis, and avoided cost determination.

Q. Does this conclude your supplemental testimony?

A. Yes.