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

A. My name is Hui Shu, my business address is 825 N.E. Multnomah, Suite 600, Portland, Oregon 97232, and my present position is senior regulatory consultant in Net Power Costs.

Qualifications

Q. Briefly describe your education and business experience.

A. I received an undergraduate degree in Electrical Engineering and finished training in the program for Master in Business Administration from University of Shanghai for Science and Technology. I received a PhD degree in Systems Science with a focus on Econometrics from Portland State University. I have worked for PacifiCorp since 1992 and have held positions in the commercial and trading and regulatory areas. I accepted my current position in April 2007.

Q. Please describe your present duties.

A. I am responsible for the coordination and preparation of net power cost and related analyses used in retail price filings. In addition, I represent the Company on power resource and other various issues with intervenor and regulatory groups associated with the six state regulatory commissions to whose jurisdiction we are subject.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I present the proposed pro-forma normalized net power costs for the test period. In addition, my testimony:

- Describes the primary reasons for the net power cost increase;
- Describes the Generation and Regulation Initiatives Decision Tools (GRID) production dispatch model and the updates used to calculate net power costs for this proceeding;
- Discusses the Company's request to begin amortization of $12.5 million of costs the Company was previously authorized to defer related to poor hydro conditions during 2005; and
- Describes in more detail, the net power cost portion of the Generation Cost Adjustment Mechanism proposed in PacifiCorp witness Ms. Kelly's testimony.

Net Power Cost Results

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

A. The proposed net power costs are approximately $451.1 million for the Company's west control area. The Washington allocated share is approximately $101.2 million.

Q. What is the impact of the net power cost increase on a Washington allocated basis?

A. In Docket UE-061546, the Commission authorized the company to recover net power costs of approximately $92 million on a Washington basis. The cost increase above the level in rates is due to a variety of factors. The factors with the largest impact include the expiration of long-term firm purchase power contracts, increased firm wheeling expenses, lower hydro generation at Company owned facilities, and revised expectations for the Grant Reasonable contract. These factors are partially offset by reductions in net power costs associated with new renewable wind resources.

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

A. Purchase power contracts generally reflect wholesale electric market prices at the time they were executed. As wholesale electric market prices increase, the cost of replacement power increases when a contract expires. This filing reflects the expiration of various contracts including the 400 megawatt TransAlta contract, and the increased costs of replacement power associated with these expiring contracts.

Q. What is the primary reason for the increase in firm wheeling expenses?

A. A low priced formula power transfer (FPT) wheeling contract with BPA expired and was converted to a higher priced BPA point-to-point (PTP) contract because BPA is eliminating FPT contracts when they expire. The current wheeling expenses also include payments for new BPA PTP wheeling contracts and wheeling to move generation from the new Goodnoe Hills wind project to the Company's system.

Q. Please explain the change in assumptions that resulted in a lower level of Company owned hydro generation.

A. The hydro generation data was updated to more closely reflect the actual operation of the hydro plants on a normalized basis. The update includes 48-month normalized maintenance and forced outages, changes resulting from the implementation of the new FERC licenses effective on January 1, 2006, as well as reduction in capability of some plants.

Q. Please explain the cost increase related to the Grant Reasonable portion of the Grant purchase power contract?

A. The Company receives an allocated share of revenue from the Grant Reasonable portion of the contract from the auction of a portion of the energy available from the Grant Priest Rapids project. The Company's share of revenue has decreased since the last general rate case. The revenue decrease was caused by an increase in Grant County's forecast of unmet district load, which reduces the amount of energy that is available for auction.

Q. Are the cost increases in this filing partially offset by the inclusion of the variable costs from renewable energy facilities that are in service or expected to be in service during the test period?

A. Yes. The net power costs include output of the 140 MW Marengo wind project located in Washington, which was placed in-service August 2007, a full test period reflection of the 101 MW Leaning Juniper wind project located in Oregon placed in-service September 2006, and the 94 MW Goodnoe wind project located in Oregon, which is presently expected to be in-service June 2008. Because the Company owns these wind facilities, the variable fuel cost of these resources is zero.

Q. Did changes in other net power cost components also reduce net power costs?

A. Yes. Changes in both net system balancing costs and Jim Bridger fuel price reduced net power costs below their level from Docket UE-061546.

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. Net power costs were modeled using the West Control Area (WCA) methodology adopted in Docket UE-061546.

Q. Please explain how the Company calculated pro forma normalized net power costs.

A. Net power costs are calculated using the GRID model. For each hour in the pro forma period the model simulates the operation of the power supply portion of the Company's west control area under a variety of stream flow conditions. The results obtained from the 40 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. Is the Company's general approach to the calculation of net power costs using the GRID model the same in this case as in Docket UE-061546?

A. Yes. The Company used the GRID model in this case consistent with the last case. Because none of the general background on GRID has changed since UE-061546, instead of including GRID background testimony, I have attached that information to my testimony as Exhibit No.___(HS-2).

Q. Please explain the modeling utilized in GRID to implement the WCA methodology.

A. GRID isolates west control area loads and resources from east control area loads and resources. West control area loads consist of:

- Retail loads for the Company's Washington, Oregon and California retail jurisdictions; and
- Long-term and short-term firm wholesale sales whose point of delivery is in the west control area

West Control Area resources consist of:

- Jim Bridger and Colstrip 4 coal generation facilities;
- Hermiston combined cycle combustion turbine generation facility;
- Owned and contracted hydro generation facilities;
- Leaning Juniper, Marengo and Goodnoe Hills wind generation facilities; and
- Long-term and short-term firm purchase power contracts excluding Oregon and California Qualifying Facility contracts.

GRID optimization functions over the west control area transmission topology which consists of third-party contractual rights and rights that PacifiCorp's merchant function has acquired from PacifiCorp's transmission function.

Q. Is there any connection between the Company's east and west control areas under the WCA methodology?

A. Yes, pursuant to the Commission's order from Docket UE-061546, a sale from the west control area to the east control area is incorporated to represent the potential sales utilizing the Company's transmission between the west and east. East/west control area exchanges and other transfers from west to east are excluded.

Q. Did the Company use the same GRID model to calculate net power costs in this case that was used in the last Washington filing?

A. Yes, with one exception. The Company's proposed net power costs were developed using GRID version 6.2. In the last Washington filing, the Company used GRID version 6.1.

Q. **Please explain the changes in GRID version 6.2 including whether they impact net power costs.**

A. The first change enhances the system balancing logic to better recognize economic displacement by decomitting eligible and not fully utilized thermal units. Previously, the Company used a manual workaround. The net power cost impact of this change is zero for the west control area.

The second change improves the dispatch of resources with zero minimum up and down time settings. The net power cost impact of this change is zero for the west control area modeling.

The third change provides the capability to include a loss payment for transmission losses as part of the total hourly transmission link cost. Transmission losses are not currently assumed in GRID for the west control area; therefore, the net power cost impact of this change is zero.

The fourth change provides the capability to include a capacity payment and other cost in the total monthly transmission link cost. Transmission capacity payments are not currently modeled for the west control area; therefore, the net power cost impact of this change is zero at the current time.

The fifth change improves the efficiency of the system balancing algorithm in the form of reduced run time. The net power cost impact of this change is zero.

The sixth change provides enhanced functionality for greater analyst efficiency. The net power cost impact of this change is zero.

GRID Model Inputs

Q. What inputs were updated for this filing?

A. The net system load, wholesale sales and purchase power expenses, wheeling expenses, market prices for natural gas and electricity, fuel expenses, hydro generation, wind generation, thermal heat rates, thermal planned maintenance and forced outage inputs were updated for this filing.

GRID model Outputs

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.___(HS-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.

Q. Please describe Exhibit No.___(HS-4).

A. This exhibit is a schedule of the Company's major sources of energy supply by major source of supply, expressed in average megawatts owned by and contracted for the Company to meet west control area load requirements for the test period. The total shown on line 11 represents the total usage of resources during the test period to serve west control area load. Line 12 consists of wholesale sales made to neighboring utilities within the Pacific Northwest and the Pacific Southwest as calculated from the production cost model study. Line 13 represents the Company's west control area load net of special sales.

Q. Please describe Exhibit No.___(HS-5).

A. This exhibit lists the major sources of peak generation capability for the Company's west control area winter and summer peak loads and the Company's energy load for the pro forma period.

Hydro Deferral

Q. Please describe the history of the Company's power cost deferral for poor hydro conditions that occurred during 2005.

A. On March 17, 2005, in Docket No. UE-050412 the Company requested that the Commission authorize the Company to defer, commencing with the date of the filing, increased power costs caused by the continuation of the then-current low hydro trend. The Company sought to defer these costs for later inclusion in rates, to be considered as part of the Company's next general rate case. The hydro deferral petition was later consolidated with the Company's general rate case in Docket UE-050684. In that docket, the Company requested recovery of $8.3 million of deferred costs under the Revised Protocol allocation methodology based on deferrals through December 31, 2005. The Commission approved the Company's request for deferred accounting stating:

> PacifiCorp is authorized to create a deferral account and defer costs according to the accounting described in the petition beginning March 18, 2005 and ending with the effective date of this order. We extend this period beyond December 2005 in order to reflect that conditions in 2006 may have affected conditions during the winter of 2005/2006. The Company bears the burden to demonstrate that it continued to face

> extraordinary circumstances from January through the date of this order at such time as it seeks to recover any deferred cost balance in rates.

Q. Did the Company continue to face extraordinary hydro conditions beyond December 2005?

A. No. The extraordinarily poor hydro conditions as defined by a comparison of actual hydro generation compared to the normalized level of generation in rates did not continue in 2006. Actual hydro generation exceeded the normalized level included in rates for the period January 1, 2006 through April 16, 2006. Therefore, the deferral mechanism should be curtailed at the end of December 2005.

Q. What was the Commission's decision on recovery of deferred costs in Docket UE-050684 /UE-050412?

A. The Commission stated:

> Accordingly, we determine that the record does not support recovering deferred hydroelectric costs in rates at this time. In a future proceeding, the Company may request recovery of any balance in the deferred account we authorize in this order. However, any amounts deferred using the Revised Protocol must be adjusted to be consistent with the interstate cost allocation method we ultimately approve. In addition, the Company must demonstrate that any amounts it requests be recovered in rates were incurred prudently and meet the criteria stated above in Paragraph 309.

Q. **Please list the criteria stated in paragraph 309.**

A. Paragraph 309 of the order stated:

> A Company must demonstrate that any increase in costs above normalized levels are prudent, that the use of a deferral mechanism is appropriate and that Company owned resources were used to benefit retail ratepayers.
>
> A Company must demonstrate prudence of power costs for which it seeks recovery, separate ordinary factors driving increases in costs from extraordinary factors, offset increased costs with increased revenues and establish a well supported baseline for measuring excess power costs.

Q. Were the excess net power costs incurred by the Company prudent?

A. Yes. The costs were incurred to provide safe and reliable service to Washington customers at a reasonable cost. The answers to a couple of pertinent questions further demonstrate that the excess costs incurred by the Company were prudent. The first question is whether or not the Company is obligated to replace the lost hydro generation so that customers can be served. The answer to the first question is clear, the Company is obligated to meet customer loads in a safe and reliable manner. The second question is whether or not the level of costs incurred is reasonable and prudent. To determine prudence from this perspective it is necessary to review options the Company had to replace lost hydro generation. West control area loads are met with existing hydro, thermal and long-term purchase power generation and short-term wholesale market purchases. Since it does not make sense to enter a new long-term purchase power contract to cover shorter term hydro conditions, the options available to replace the lost hydro generation are additional short-term market purchases and/or the redispatch of existing thermal resources. The Company did both in this case. Since incremental market purchases were executed at market prices and thermal generation costs were below market prices, both of these employed options are prudent from a cost perspective.

Q. Is the hydro deferral mechanism appropriate?

A. Yes. Deferral mechanisms exist for the express purpose of capturing the impact of extraordinary circumstances. In the Commission's order on the petition for reconsideration in this docket the Commission stated:

> We approved PacifiCorp's request to defer excess power costs due to declining hydro electric generation, finding that low water conditions through most of 2005 were extraordinary.

As explained above, the extraordinary conditions did not continue for the Company beyond December 2005. Therefore, the mechanism is appropriate from the March 18, 2005 Commission approved implementation date through December 31, 2005.

Q. Did Company-owned west control area resources serve Washington retail customers during the hydro deferral period?

A. Yes. All resources within the west control area were used to serve Washington retail customer load requirements.

Q. Does the Company's hydro deferral mechanism separate ordinary factors driving cost increases from extraordinary factors?

A. Yes. The Company's calculation only seeks recovery of costs incurred to replace lost hydro generation due to the extraordinary circumstances. For example, the market price of energy secured to replace lost hydro generation is based on the cost of purchase power transactions entered prior to March 17, 2005. In other words, the market price calculation excludes the impact of transactions that were entered prior to the poor hydro conditions. Further, the mechanism does not seek recovery of other power cost increases that occurred before and/or during that period.

Q. Does the Company's analysis consider whether there were revenue increases as an offset to increased costs?

A. Yes. The Company evaluated whether there was an offset due to retail load growth and concluded that there was not a net revenue increase. The cost of serving the incremental load was higher than the incremental revenue from the incremental load. A copy of that analysis is attached to my testimony as Exhibit No.___(HS-6).

Q. Did the Company also consider whether there were cost decreases due to changes in west control area thermal generation?

A. Yes. The deferral calculation includes a benefit for higher net thermal generation than was included in rates. This benefit reduces the cost of the hydro deferral by $2.4 million on a Washington basis.

Q. Was a well established baseline used for measuring excess net power costs?

A. Yes. Authorized hydro generation at the Company's west control area facilities was used as a baseline to calculate the cost of the hydro deferral. The authorized level of west control area thermal generation was also used to determine the benefit associated with changes in thermal generation used as an offset to the deferred hydro cost.

Q. Was the hydro deferral calculation updated to reflect the west control area allocation methodology adopted in Docket UE-061546?

A. Yes. The calculation was updated to reflect poor hydro conditions through December 2005 consistent with the west control area allocation methodology, to reflect requirements of paragraph 309 discussed above in my testimony and to reflect interest accrued on the unamortized balance through the expected date of the order in this case. The updated hydro deferred cost the Company is requesting recovery of is $12.5 million. The updated calculation is attached to my testimony as Exhibit No.___(HS-7).

Q. What interest rate was used for the interest accrual?

A. The interest rate used is the Commission authorized 8.10 percent weighted average cost of capital.

Q. The amount requested in this filing is higher than the $8.3 million previously requested in Docket UE-050684. Please explain why the request is higher.

A. The request in this filing is higher because Washington is allocated a larger share of the costs of hydro facilities under the WCA methodology than under Revised Protocol. As such, Washington bears a larger allocation of the impacts of poor hydro conditions.

Generation Cost Adjustment Mechanism

Q. In Ms. Kelly's testimony, she provides an outline of the Company's GCAM proposal. Please describe the annual update of forecasted net power costs associated with the GCAM filing.

A. The filing would be made on October 15 of each year starting in 2009 and will update all net power cost components consistent with the prior order from the Company's last Washington general rate case. The testimony submitted with this filing will also include an explanation of the primary causes of variations in net power costs since the last approved filing. Under the Company's proposal, there would be two updates to the data during the proceeding to ensure that the final NPC in rates is as accurate as possible

Q. Please describe the first net power cost update that would occur during the proceeding.

A. The first update will be made, as part of the Company's rebuttal case in any GCAM, on or about March 15 of each year (the actual date will be set in the procedural schedule for the filing) following the annual filing and will be limited to known and measurable changes in elements of net power costs. Those items include:

- The December 31 forward price curve for electricity and natural gas;
- Fuel cost updates; and
- New wholesale sales, purchases and wheeling contracts or contract amendments

Q. Please describe the second net power cost update that would occur during the proceeding.

A. The second and final update will be made on or about June 10 of each year (after the Commission has issued its order) and will include:

- Commission ordered net power cost adjustments;
- The March 30 forward price curve for electricity and natural gas;
- Fuel cost updates; and
- Wholesale sales, purchase power and wheeling contracts executed or amended through June 1.

This second and final net power cost update will be subject to discovery and audit for compliance with the Commission's order prior to its adoption. Any rate change based on this final update would be effective July 1.

Q. Does the Company have recommendations that would streamline the mechanism?

A. Yes. The Company should be required to use the same version of the GRID production dispatch model that was used in the prior general rate case, unless there is agreement among the parties that an updated version of the model can be used in a specific filing. The Company should also be required to use the same methodology used to estimate net power costs in the prior docket. These requirements will streamline the process by eliminating potential controversies that could arise during the docket. Essentially, the filing will update only inputs and include new resource additions.

Q. Does this conclude your direct testimony?

A. Yes.