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

A. My name is Mark T. Widmer, my business address is 825 N.E. Multnomah, Suite 800, Portland, Oregon 97232, and my present title is Director, Net Power Costs.

Qualifications

Q. Briefly describe your education and business experience.

A. I received an undergraduate degree in Business Administration from Oregon State University. I have worked for PacifiCorp since 1980 and have held various positions in the power supply and regulatory areas. I was promoted to my present position in September 2004.

Q. Please describe your current duties.

A. I am responsible for the coordination and preparation of net power cost and related analyses used in retail price filings, the Integrated Resource Plan (IRP) process and the Multi-State Process (MSP). In addition, I represent the Company on power resource and other various issues with intervener and regulatory groups associated with the six state regulatory commissions which have jurisdiction over the Company.

Summary of Testimony

Q. Will you please summarize your testimony?

A. I provide quantitative analysis of the Company's historical net power cost exposure and how that relationship has changed to the point that the Company's risk has become very asymmetrical. I present the Company's proposed Power

Cost Adjustment Mechanism (PCAM), which if adopted, would better balance net power cost exposure between the Company and customers.

Asymmetric Risk

Q. Why is the Company requesting a PCAM?

A. The Company's net power cost exposure to losses is asymmetric. Market prices can only fall to zero while market price increases are, theoretically, unlimited. Even though it is unlikely that market prices will fall to zero or increase infinitely, the limitations are relevant. For example, as explained below, since 1989 the largest decrease in net power costs is dwarfed by the largest increase in net power costs above authorized levels. This is causing the Company to bear a disproportionate share of net power costs incurred to serve retail customers. As a consequence, our opportunity to earn our authorized rate of return over the long run will be greatly diminished if not eliminated, because net power costs are such a large component of revenue requirement.

Q. **Please define net power cost exposure.**

A. In this context I have defined net power cost exposure as the variance between actual and authorized net power costs.

Q. Please explain the information shown on Exhibit UP&L___ (MTW-1).

A. Exhibit UP&L___ (MTW-1) shows the historical net power cost exposure experienced from 1990 through 2004. These figures exclude the $146 million recovered from Utah customers for the energy crisis. As shown, the net power cost exposure varied between a $32 million gain and a $738.5 million loss on a total Company basis, excluding recovery for the energy crisis. In aggregate and including recovery for the energy crisis, losses exceeded gains by $1.1 billion total Company based on Utah authorized net power costs.

Q. Has the Company's net power cost exposure been constant over that period?

A. No. Beginning in 2000, with the start of the Western energy crisis, the exposure has become very asymmetric. From 1990 through 1999, the Company's net power cost exposure averaged $7.1 million total Company and from 2000-2004 it averaged approximately $223 million in excess costs. In percentage terms, the exposure for the 2000-2004 period increased by over 3,100 percent compared to the 1990-1999 period average.

Q. Are the factors which contribute to the net power cost exposure asymmetry controllable by the Company?

A. No. Deviations from net power costs in rates are primarily related to factors not controllable by the Company. For example, hydro conditions, weather conditions, retail loads, wholesale market prices for natural gas and electricity and the timing of forced outages are not controllable. While these potential causes have always been present, the cost of addressing these factors has increased dramatically over the past 5 years. The overwhelming cause of the cost increase is due to an increase in wholesale market prices and price volatility. For example, actual hydro generation for fiscal 2004 was 1.5 million MWh below normal due to continued drought conditions. At market prices prevalent from 1990 through 1999, replacement power would have cost $25 million on average. At recent market prices, replacement power would have cost approximately $120 million. Historical market prices are shown in Exhibit UP&L___ (MTW-2). More recently we have seen natural gas prices approximately double over the last year alone. Unless changes are made to the Company's Utah net power cost recovery regulatory model, this asymmetry will continue to increase as wholesale market prices and price volatility increase.

Q. What is the expected trend for the wholesale market price of electricity?

A. While the expected trend is down from the current high levels over the next several years, the prices are expected to stay high by historical standards and there will be some level of year-to-year volatility in wholesale market prices. Exhibit UP&L___ (MTW-3) is the Company's most recent Official Price Projection of future market prices.

Q. Have prudent steps been taken to insulate customers and shareholders from net power cost exposure?

A. Yes. The Company engages in the IRP process. Through the IRP process the Company identifies resource requirements which have resulted in the Company filing request for proposals ("RFPs") for resources to meet load requirements on a least-cost, risk-adjusted basis. This process provides further assurances to the Commission and customers as to the prudent nature of our net power costs involving power purchases and/or the construction of generation facilities. The Company has also increased its emphasis on transactions that would reduce risk. These efforts were undertaken to further align the interests of shareholders and customers. Finally, under the proposed PCAM described below, the sharing bands would result in the Company shouldering a significant portion of the volatility between rate cases, thereby reinforcing the Company's incentive to manage its system and associated risks prudently.

Q. Has net power cost exposure been recognized and addressed by other Commissions that regulate utilities located in the WECC?

A. Yes. As described in a recent Standard and Poor's research article titled "Fuel and Power Adjusters Underpin Post-Crisis Credit Quality of Western Utilities", Exhibit UP&L___ (MTW-4), most of the investor owned electric utilities located in the WECC currently have some form of power cost recovery mechanism, with the exception of a few utilities including PacifiCorp and Portland General Electric (PGE), and Public Service of New Mexico and Tucson which are resource long. An important factor that should be considered in the Commission's evaluation of our request is the fact that the Company has more exposure than many of the other utilities located throughout the WECC due to variability of hydro resources in our portfolio.

Q. How does the Company propose to rebalance the asymmetric net power cost exposure that the Company has been shouldering?

A. The Commission should adopt the Company's proposed PCAM to rebalance net power cost exposure between customers and the Company so they are closer to historic levels. Failure to do so would likely result in a systemic under recovery of net power costs that are prudently incurred to serve customers and would not consistently provide our customers proper price signals for energy consumption decisions.

Proposed PCAM

Q. Please explain how net power costs will be recovered in Utah under the Company's proposed PCAM.

A. The PCAM is an incentive-based mechanism that would share variations in adjusted actual net power costs from the authorized baseline net power costs with one exception. The one exception is that 100 percent of cost increases or decreases related to Qualifying Facility (QF) contracts should be recovered from customers since the purchases are required by PURPA. In addition, the 2005 Energy Policy Act (EPAct) requires that electric utilities recover all prudently incurred costs. Section 210 (m) (7) states:

> The Commission shall issue and enforce such regulations as are necessary to ensure that an electric utility that purchases electric energy or capacity from a qualifying cogeneration facility or qualifying small power production facility in accordance with any legally enforceable obligation entered into or imposed under this section recovers all prudently incurred costs associated with the purchase.

All other costs would be subject to asymmetrical sharing bands that allocate 90 percent of cost increases to customers and 100 percent of cost decreases to customers.

Q. Please explain how the proposed PCAM will operate.

A. In the ongoing operation of the PCAM, base net power costs in rates will be established in general rate cases. Deferred Net Power Costs will be calculated monthly and are equal to the Utah allocated share of the difference between total Company Base Net Power Costs and total Company Adjusted Actual Net Power Costs plus a Utah retail load adjustment. If the Deferred Net Power Costs is positive, the Company has collected more from customers than the costs incurred and 100 percent of the net excess will be returned to customers over a 12 month period. If the Deferred Net Power Cost is negative, the Company has collected less from customers than the costs incurred and only 90 percent will be recovered from customers over a 12 month period. In other words, if the Company recovers less than the Adjusted Actual Net Power Cost, the Company will absorb 10 percent of the cost increase as risk sharing. This asymmetric risk sharing mechanism will provide the Company a significant incentive to keep total net power costs as low as possible while providing safe, adequate and reliable service. Mr. Taylor describes the steps necessary to allocate the deferrals to Utah pursuant to Revised Protocol.

Q. Please explain the Utah retail load adjustment.

A. The adjustment captures the monthly retail revenue impact of changes in Utah load from the level included in retail rates. Through this adjustment, increased retail revenue related to load increases is netted against increased net power costs and conversely, revenue decreases related to declines in retail loads is netted against decreased net power costs. The revenue adjustment would be calculated by multiplying the portion of the retail rate related to net power costs by the change in load from the in rates level.

Q. Should the accrued balances accrue interest?

A. Yes. Both customers and the Company should be compensated for the time value of money for accrued balances, whether positive or negative. The interest rate used should be the Company's authorized rate of return.

Q. Please define and describe the terms that the Company proposes for the management of the PCAM.

A. **<u>Base Net Power Costs</u>** are the authorized net power costs in rates. The measurement period should be tied to the balancing account trigger, which is discussed below. Base Net Power Costs will be in effect until the Company's rates are adjusted through a general rate case.

<u>Adjusted Actual Net Power Costs</u> is the sum of the total Company amounts recorded in FERC Accounts: 501, 503 and 547 (Steam Production Fuel Expense) for coal, steam and natural gas purchased and or sold, 555 (Purchased Power), 565 (Wheeling), 447 (Sales for Resale). These actual amounts would be further adjusted to; 1) remove actual costs consistent with the rate setting process so comparable costs are being used in the accrual calculation, 2) remove prior period accounting entries recorded during the accrual period that are not applicable to the current period, and 3) to include Commission-adopted disallowance adjustments from the most recent Utah rate case so comparable costs are being used in the accrual calculation. An example of an item 1 adjustment would be the removal of Bonneville Regional Credit costs because they are not applicable to Utah. An example of an item 2 adjustment would be the removal of fuel costs booked to the current period that are related to a historical period outside the measurement period. An example of an item 3 item adjustment would be the Commission adopted Sacramento Municipal Utility District (SMUD) wholesale sales revenue imputation adjustment.

Trigger is the $20 million Deferred Net Power Cost threshold balance at which the Company may return or recover balances accrued from customers.

Q. Is the Company proposing to establish a fixed schedule for requesting recovery of or return to customers of accrued balances?

A. No. Rather than establishing a fixed schedule for such filings, the Company proposes that a plus or minus $20 million accrued balance on a Utah basis be established as a trigger. Once the trigger is reached, the Company can return or collect balances from customers. This approach is more beneficial than setting a fixed schedule because it should reduce the number of rate changes during periods of lower net power cost volatility, reduce rate shock during periods of higher volatility when balances could be much higher, and provide more current price signals during periods of higher volatility.

Q. How does the Company propose to allocate the sur-charges and sur-credits to customers?

A. Both will be spread to customers on a uniform cents-per-kwh basis to all customer classes in order to reflect changes is costs per MWh incurred by the Company to serve customers. Because differences in delivery voltage result in different line losses and power requirements, the Company proposes to vary the sur-charge and sur-credit amounts by delivery voltage. The loss factors in effect at the time time of the accrual would be used for this determination.

Q. Is the PCAM designed to take into account all net power cost components?

A. Yes. The mechanism is designed to include the impact of cost changes for fuel, wheeling and purchase power expenses and wholesale electricity and natural gas sales modeled in the Company's production dispatch model.

Q. Please explain Exhibit UP&L__ (MTW-5).

A. Exhibit UP&L__ (MTW-5) is an illustration of how the Company's proposed PCAM would have operated during calendar year 2004. As shown, the total Company net power cost variance from Utah authorized results was $233.6 million. After exclusion of the Company's $22.2 million share, $3.3 million was related to east hydro, $.4 million was related to Mid Columbia hydro. $5.5 million was related to existing QF contracts, .8 million was related to new QFs and $$62.5 million was related to all other, which includes fuel prices, market prices, contract changes etc. Utah's allocated share of these costs would have been $$72.4 million. The revenue impact of the load changes was $(40.9) million, leaving a net Utah impact of $31.5 million.

Q. Is the proposed PCAM similar to currently effective commodity balancing account mechanism used by Questar?

A. Yes, the function of the proposed PCAM is similar to Questar's natural gas commodity balancing account. The major difference is that the Questar mechanism provides 100% recovery of cost increases and the Company's proposed mechanism provides recovery of 90 percent of cost increases between rate effective periods.

Q. Should accrued costs be subject to a prudence review?

A. Yes. However, costs and revenues related to existing contracts and resources that have previously been included in rates should be exempt from a prudence review on a cost basis. Of course, the manner in which in which generation facilities were operated and contracts dispatched during the accrual period should be subject to review along with other new contracts. This review is also intended to cover whatever accounting issues may arise and ensure that Commissions disallowances are accounted for properly.

Q. Does this conclude your direct testimony?

A. Yes.