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

A. My name is Mark Widmer, my business address is 825 N.E. Multnomah, Suite 600, Portland, Oregon 97232, and my present position is Principal System Planner.

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 1998.

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. 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.

Summary of Testimony

Q. Will you please summarize your testimony?

A. I will provide information on how input data is normalized in the Company's production cost model and will present the results of the production cost model study for the 12-month period ending December 31, 1998. I will also discuss the Wyoming Wind Project.

Determination of Net Power Cost

Q. Please explain how net power costs are calculated.

A. The Company calculates net power costs on a normalized basis using its production cost model, PD/Mac. The model is used to simulate the operation of the power supply portion of the Company under a variety of stream flow and associated energy market conditions. The results obtained from the various stream flow conditions are averaged and the appropriate cost data is applied to determine an expected net power cost under normal conditions for the test period. The use of normalized net power costs stabilizes the prices paid by the Company's retail customers and places the risks and responsibility of managing energy costs, over which the customer has no control, on the Company.

Q. Please explain the production cost model and how it is used to estimate net power costs.

A. The development of expected net power costs begins with the selection of either a forecasted or historic test period. My discussion will focus on the use of a historical test period. I have divided the description of the power cost model into three categories:

1. The inputs that go into the model.
2. The process of normalizing the model inputs.
3. The output provided by the model.

Model Inputs

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

A. Inputs into the production cost model include retail loads, thermal plant data, hydroelectric generation data, firm wholesale sales, firm wholesale purchases, firm wheeling contracts, Pacific Northwest regional data, and nonfirm wholesale sales and purchase market data.

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

A. The retail load represents the monthly temperature normalized firm retail energy loads that the Company served within all of its jurisdictions for the twelve-month period ended, December 31, 1998. These loads have been adjusted to reflect normal temperature conditions.

Q. Please describe the thermal plant input data.

A. The amount of energy available from each thermal unit and the unit cost of the energy is needed to calculate net power costs. To determine the amount of energy available, the Company averages four years of each unit's historical operating equivalent availability reduced by the unit's four-year average maintenance.

The unit cost of energy for each unit is determined by using a four-year average of historical burn rate data and historical normalized coal prices. By using four-year averages for maintenance, historical availability and burn rate data, annual fluctuations in unit operation and performance are smoothed. The four-year period used by the Company for this filing is 1995 through 1998.

Q. Please describe the hydroelectric generation input data.

A. The hydroelectric generation in the Pacific Northwest is directly related to stream flow conditions, making it an integral part of determining the Company's net power cost. Fifty years of monthly hydroelectric generation for Company-owned hydro plants in the Northwest and Mid-Columbia purchased resources are input into the model. The hydro data that is input into the production cost model is from the

Bonneville Power Administration (BPA) Hydro Regulation computer program (Hydro Regulation). Data from the Hydro Regulation is based on actual stream flows for the period August 1929 through July 1978. The Hydro Regulation simulates the hydroelectric generation at each facility on the major rivers in the Pacific Northwest based on inputs provided by each member of the Northwest Power Pool, Idaho Power Company, and the Assured Operating Plan of the Canadian Utilities. The purpose of the Hydro Regulation is to maximize the firm energy generation of the Pacific Northwest hydroelectric system, and is based on hydroelectric plant efficiencies, storage capabilities and requirements, minimum flow requirements (including fish requirements), regional loads and resources, and non-power operating constraints.

Q. Is the input of hydro generation located outside of the Northwest modeled in the same manner as the Pacific Northwest hydro generation?

A. No. The input of hydro generation located in Utah and Southeast Idaho was calculated as the actual average monthly hydroelectric generation for the years 1974 through 1998. A shorter time frame is used for the Utah and Southeast Idaho hydro resources than the Company's other hydro resources because their relative size is small, there is no overall area model analogous to the Hydro Regulation Model in the Northwest and there is a lack of reliable data for the earlier years.

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

A. The data for firm wholesale sales, purchases, and wheeling are all based on contracts to which the Company is a party. Each contract specifies the basis of quantity and price. The contract may specify an exact quantity of capacity and energy or a range bounded by a maximum and minimum amount, or it may be based on the actual operation of a specific facility. The price may also be specifically stated, may refer to a rate schedule, a market index such as COB or Palo Verde, or may be based on some type of formula.

Q. Please describe the Pacific Northwest regional input data.

A. There are several types of regional data required as inputs to the model. The most significant is the Pacific Northwest regional non-firm load and resource balance. The non-firm regional balance can be either surplus or deficit. A surplus occurs when the amount of energy available within the region is in excess of the region's firm load and a deficit occurs when the region's firm load exceeds available resources. The regional balance is closely related to the region's hydro capability, and is therefore considered to be a water year dependent variable. The inputs include fifty water years of monthly data. The nonfirm balances are developed by comparing the region's current loads and resources to the resources available under each of the fifty water year conditions. As indicated earlier, the Company uses data prepared for the Hydro Regulation as its data source. Other data used to represent the Company's interactions within the region include: the amount of thermal resources considered to be high cost, and the regional storage capabilities.

Q. Please describe the nonfirm wholesale sales and purchase input assumptions.

A. The production cost model requires inputs relating to four non-firm wholesale sales markets. These markets are the Pacific Northwest, California (via the Pacific Northwest / Pacific Southwest Intertie), the Desert Southwest, and Nevada. The size of each market is determined by the available firm transmission reduced by any firm wholesale sales scheduled over the respective transmission path, forced outages, or other known restrictions. Nonfirm wholesale sales prices are set to reflect prices expected under normal conditions and are based on historical nonfirm wholesale prices, water conditions and reservoir levels in the Pacific Northwest, levels of competition experienced and natural gas prices. Nonfirm prices are based on normalized hydro conditions and fuel prices.

Normalization

Q. Please explain what is meant by normalization and how it applies to the production cost model for historical test years.

A. Normalization is the process of modifying actual test year data by removing all known abnormalities and making adjustments for all known changes. Normalization produces test year results that are representative of expected conditions with none of the abnormalities that occur in each actual year. The following are examples of normalization adjustments made by the Company to adjust input data for the production cost model:

1. The system load net of special sales is adjusted to reflect loads that would have occurred under normal temperature conditions in the Company's service area.
2. The Company's thermal plant data is normalized by making adjustments for major known and measurable changes that affect the output of the plant. Fuel costs for each plant are based on the fuel costs incurred during the historical test period, adjusted for known and measurable changes.

3. Firm wholesale power purchase and sales under long-term contracts with other entities are normalized by making adjustments for contractual changes in price and quantity.

4. Power purchases from qualifying facilities are normalized by making adjustments for changes in price and quantity.

5. Transmission availability is normalized by making adjustments for known changes to transmission paths such as upgrades to the Pacific Northwest / Pacific Southwest intertie or line reratings.

6. The availability of energy from Company-owned and purchased hydroelectric generation is normalized by running the production cost model for each of the 50 different water years identified in the Hydro Regulation. The resultant 50 sets of thermal generation, nonfirm sales and purchases, and hydroelectric generation are then averaged using a weighting method which accounts for 115 years of stream flow data as measured on the Columbia River at The Dalles.

Q. You stated that hydroelectric generation is normalized by using historical water data. Please explain why the regulatory commissions and the utilities of the Pacific Northwest have adopted the use of production cost studies that employ historical water conditions for making these normalization adjustments.

A. In any hydroelectric-oriented utility system, water supply is one of the major variables affecting power supply. The operation of the thermal electric resources both within and outside the Pacific Northwest are directly affected by water conditions within the Pacific Northwest. During periods when the stream flows are at their lowest, it is necessary for utilities to operate their thermal electric resources at a higher level, thereby experiencing relatively high operating expenses, primarily due to fuel costs. Conversely, under conditions of high stream flows, excess hydroelectric production may be used to reduce the generation of the more expensive thermal electric plants, which in turn results in lower operating expenses of some utilities and an increase in the revenues of other utilities, or any combination thereof. No one water condition can be used to simulate all the variables that are met under normal operating conditions. Utilities and regulatory commissions, therefore, have adopted production cost analysis that simulates the operation of the entire system using historical water conditions, as being representative of what can reasonably be expected to occur.

Model Outputs

Q. What variables are calculated from the production cost study?

A. The variables that are generally dependent upon water supply are calculated for each month of the study and are outputs of the model. These variables are:

1. The amount of thermal generation required;
2. Secondary sales both within the Pacific Northwest region, and in markets outside the region;
3. The secondary energy purchased. The availability of secondary energy is based on the level of surplus hydroelectric generation available in the Pacific Northwest as well as the Company's load and resource balance.
4. Interchange energy and hydroelectric storage; transactions as performed under the Pacific Northwest Coordination Agreement; and

5. The hydroelectric energy spilled due to the lack of a market.

Q. Would you please describe the service area that the Company's production cost study encompasses and explain why it is necessary to analyze such an extensive area.

A. The Company's six-state system is fully integrated with members of the Northwest and Rocky Mountain Power Pools, making it necessary to analyze the effect on the Company's power supply operations brought about by the operations of all the utilities in this area. The wholesale sales markets available to the Pacific Northwest region, mainly those in California and the Desert Southwest, must also be represented in order to evaluate their direct effect on the operations of the utilities within the Pacific Northwest.

Q. Would you please give an example of the interaction of operations between the utilities within this study area?

A. As one example, assume that the Company has an energy surplus in one month as a result of the integrated operation of regional hydroelectric facilities. Pursuant to the provisions of the Pacific Northwest Coordination Agreement to which the Company is a party, this surplus must first be made available to the other parties to the Agreement who are energy deficient. Once this obligation has been satisfied, any remaining Company surplus could then be made available to wholesale sales markets inside or outside the Pacific Northwest. Because wholesale sales markets are highly competitive, the regional energy surplus situation must be examined before the ultimate disposition of any Company surplus can be determined.

Q. Do you believe that the production cost model adequately represents the Company's operating relationship with the other utilities and markets?

A. Yes.

Q. Do the results of the production cost model match the actual net power cost of the Company?

A. No, they do not. The results of the production cost model are not intended to match actual costs on a year by year basis, but are intended to provide results which are fair and reasonable and simulate the operation of the system under normal conditions. The fundamental difference between using normalized and actual net power costs is the placement of risks and rewards associated with over running and under running net power costs. Using actual information places the risks and rewards on customers, while using normalized information places the risks and rewards on the Company and its shareholders.

Q. What has the Company's experience been using the production cost model in other jurisdictions?

A. The production cost model has been used for regulatory filing and reporting requirements in all of the jurisdictions in which the Company operates. It has not been the subject of major controversy in the other states in which the Company serves as the various parties have been comfortable and familiar with the model and the reasonableness of the results it produces.

Q. Does the Company's filing include all net power cost adjustments stipulated to and adopted in Docket No. 97-035-01?

A. Yes.

Q. Please describe Exhibit UP&L __.1 (MTW-1), Table 1.

A. Table 1 is a schedule of the Company's major sources of energy supply by major source of supply, expressed in average megawatts, owned and contracted for by the Company to meet system load requirements, for the 12-month test period ended December 31, 1998. The total shown on line 13, represents the total normalized usage of resources during the test period to serve system load. The total system load is represented by lines 13 through 15. Line 14 consists of wholesales sales made to neighboring utilities within the Pacific Northwest, the Pacific Southwest, and the Desert Southwest as calculated from the production cost model study. Line 15 represents the Company's System Load.

Q. Please describe Exhibit UP&L__.1 (MTW-1), Table 2.

A. Table 2 shows the major sources of peak generation capability for the Company's winter and summer peak loads and the Company's normalized energy load for the twelve month test period ended December 31, 1998.

Q. How are the results of the production cost study used in this rate proceeding?

A. The resulting purchased power expense, fuel and wheeling expenses, and wholesale sales revenues are included in Jeffrey K. Larsen's Exhibit UP&L __.1 (JKL-1).

Wyoming Wind Project

Q. Please describe the Wyoming Wind Project.

A. The Wyoming Wind Project consists of 69 wind turbines for a total capacity of 41.4 MW and an annual projected output of 154 GWH at a 42.6% capacity factor. The Wyoming Wind Project, located at Foote Creek Rim in southeastern Wyoming, has been developed by ToyoWest Wyoming, LLC and will be operated and maintained by SeaWest Wyoming LLC. Two utilities, PacifiCorp and Eugene Water & Electric

Board (EWEB) own the Wyoming Wind Project’s generating facilities. In addition to the two owners, BPA has signed a Power Purchase Agreement to purchase 15 MW of the Project's output. Initial synchronization to the grid and delivery of energy occurred in October, 1998 and commercial operation started April, 1999.

Q. Why is PacifiCorp participating in the Wyoming Wind Project?

A. PacifiCorp’s decision to participate in the project is based on a Company commitment to the development of cost-effective renewable resource alternatives. For a number of years, PacifiCorp has included in its Strategic Goals specific references to the development of environmental resource alternatives and the diversification of resources.

Q. What are the benefits of the project?

A. Participation in the project not only furthers the Company's efforts to meet its Environmental Strategic Goal and the Company’s RAMPP action plans; it will also provide valuable operational experience and knowledge that will allow the Company to develop and use renewable technologies more effectively in the future. There is a definite need for the Company to gain knowledge with renewable technologies and that knowledge can only be gained through actual hands-on experience with various technologies. Sharing the wind project’s costs among several utilities allows PacifiCorp to minimize the risks involved with newer technologies.

The experience being gained from the Wyoming Wind Project will allow PacifiCorp to develop ways of integrating this type of resource into the system, and will reveal how these plants affect the system use of other resources for load following and how they affect the local transmission and distribution systems.

Q. What do you recommend regarding the Wyoming Wind Project?

A. The Wyoming Wind Project is a prudently acquired resource which is used and useful. Therefore, I recommend that the acquisition costs of the Wyoming wind resources be included in rate base and allowed to earn the allowed rate of return. The operating expenses of these resources should be included in establishing the Company's revenue requirement.

Q. Does this conclude your direct testimony?

A. Yes.