Exhibit No. ___(MTW-1T)
Docket No. UE-03_____
2003 PP&L Rate Case
Witness: Mark T. Widmer

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PACIFICORP dba Pacific Power & Light Company, Respondent.	Docket No. UE-03______

PACIFICORP

DIRECT TESTIMONY OF MARK T. WIDMER

December 2003

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 NE Multnomah, Suite 800, Portland, Oregon 97232, and my present position is Manager, Regulation.

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 March 2001.

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 that have jurisdiction over the Company's retail operations.

Summary of Testimony

Q. Please summarize your testimony.

A. I will present the results of the production cost model study for the 12-month period ending March 31, 2003. I will describe the Company's production cost model, the Generation and Regulation Initiatives Decision Tools ("GRID") model, which is used to calculate net power costs. I will also provide information on how input data is normalized in GRID and the rationale for doing so. My testimony also presents the results of the PacifiCorp Prudence Review of Generating Resources Acquired Since 1986, Joint Report, Docket No. UE-991832 ("Joint Report"). I will also demonstrate that these resources were acquired to satisfy the load and demand of Washington customers.

Net Power Cost Results

Q. What are the results of the Company's normalized test year net power cost study?

A. Total Company normalized net power costs for the 12-month period ending March 31, 2003 is approximately $553.0 million.

Determination of Net Power Cost

Q. Please explain net power costs.

A. Net power costs are defined as the sum of fuel expenses, wholesale purchase expenses and wheeling expenses, less wholesale sales revenue.

Q. Were the proposed net power costs that you have sponsored developed with the same production dispatch model used in the Company's last Washington filing?

A. No. The Company's proposed net power costs were developed using our new hourly production dispatch model, GRID 2.0.

Q. Please explain how the Company calculated net power costs.

A. The Company calculated net power costs on a normalized basis using the GRID model. The model simulates the operation of the power supply operations of the Company under a variety of stream flow conditions on an hourly basis. The results obtained from the various stream flow conditions were averaged and the appropriate cost data was applied to determine an expected net power cost under normal stream flow and weather conditions for the test period.

Q. Please explain how GRID normalizes net power costs.

A. The development of expected net power costs begins with the selection of either a forecast or historic test period. I have divided the description of the power cost model into three sections, which follow below:

1. The model used to calculate net power costs.
2. The model inputs.
3. The model output.

The GRID Model

Q. Please describe the GRID model.

A. The GRID model is the Company's hourly production dispatch model, which the Company uses to calculate net power costs. It is a server-based application that uses the following high-level technical architecture to calculate net power costs:

- An Oracle-based data repository for storage of all inputs
- A Java-based software engine for algorithm and optimization processing
- Outputs that are exportable in Excel readable format
- A web browser-based user interface

Based on requests by regulatory staffs and intervenors, the model has also been modified to run on stand-alone personal computers.

Q. Please describe the methodology employed to calculate net power costs in this docket.

A. Net power costs are calculated on an hourly basis using the GRID model. The general steps are as follows:

1. Determine the input information for the calculation, including retail load, wholesale contracts, market prices, thermal and hydro generation capability, fuel costs, transmission capability and expenses.
2. The model calculates the following pre-dispatch information:
   - Thermal availability
   - Thermal commitment
   - Hydro shaping and dispatch
   - Energy take of long-term firm contracts
   - Energy take of short-term firm contracts
   - Reserve requirement and allocation between hydro and thermal resources
3. The model determines the following information in the Dispatch (optimization) process, based on resources pre-dispatched and contracts:
   - Optimal thermal generation levels, and fuel expenses
   - Expenses (revenues) of the firm purchase (sales) contracts
   - System balancing market purchases and sales necessary to balance and optimize the system and minimize net power costs, taking into account the constraints of the Company's system
   - Expenses for purchasing additional transmission capability
4. Model outputs are used to calculate net power costs on a total Company basis, incorporating expenses (revenues) of purchase (sales) contracts that are independent of dispatched contracts, which are determined in step 3.

The main processors of the GRID model are steps 2 and 3.

Q. Please describe in general terms, the purposes of the Pre-dispatch and Dispatch processes.

A. The Dispatch process is a linear program optimization module, which determines how the available thermal resources should be dispatched given load requirements, transmission constraints and market conditions, and whether market purchases should be made to balance the system. In addition, if market conditions allow, market purchases may be used to displace more expensive thermal generation. At the same time, market sales may be made either from excess resources or market purchases, if it is economical to do so under market and transmission constraints.

Q. Does the Pre-dispatch process provide thermal availability and system energy requirements for the Dispatch process?

A. Yes. Pre-dispatch, which occurs before the Dispatch process, calculates the availability of thermal generation, dispatches hydro generation, schedules firm wholesale contracts, and determines the reserve requirement of the Company's system. I will now describe each of the calculations in more detail.

Generating Resources in Pre-dispatch

Q. Please describe how the GRID model determines thermal availability and commitment.

A. The Pre-dispatch process reads the input regarding thermal generation by unit, such as nameplate capacity, normalized outage and maintenance schedules, and calculates the available capacity of each unit for each hour. The model then determines the hourly commitment status of thermal units based on planned outage schedules, and a comparison of operating cost vs. market price if the unit is capable of cycling up and down in a short period of time. The commitment status of a unit indicates whether it is economical to bring that unit online in that particular hour. The availability of thermal units and their commitment status are used in the Dispatch process to determine how much may be generated each hour by each unit.

Q. How does the model shape and dispatch hydro generation?

A. In the Pre-dispatch process, the Company's available hydro generation from each non-run-of-river project is shaped and dispatched by hour within each month in order to maximize usage during peak load hours. The monthly shape of a non-run-of-river project is based on the hourly retail load and market prices in a month, and incorporates minimum and maximum flow for the project to account for environmental constraints. The dispatch of the generation is flat in all hours of the month for run-of-river projects. The hourly dispatched hydro generation is used in the Dispatch process to determine energy requirements for thermal generation and system balancing transactions.

Q. Does the model distinguish between short-term firm and long-term firm wholesale contracts in the Pre-dispatch process?

A. Yes. Short-term firm contracts are block energy transactions with standard terms and a term of one year or less in length. In contrast, many of the Company's long-term firm contracts have non-standard terms that provide different levels of flexibility. For modeling purposes, long-term firm contracts are categorized as one of the following six archetypes based on contract terms:

- Energy Limited (shape to price or load): the energy take of these contracts has minimum and maximum load factors. These contracts may include shaping (hourly, annual), exchange agreements, and call/put optionality.
- Generator Flat: the energy take of these contracts is tied to specific generators and is the same in all hours, which takes into consideration plant down time. There is no optionality in these contracts.
- Generator Optional: the energy take of these contracts is also tied to specific generators but is dispatched as generators with flexibility. They can be either hydro or thermal generation.
- Flat: these contracts have a fixed energy take in all hours of a period.
- Complex: the determination of energy take of these contracts requires the load and resource balances of the third party.
- No Energy: these contracts do not take energy. They are contracts for capacity transactions only.

In the Pre-dispatch process, long-term firm purchase and sales contracts are dispatched per the specific algorithms designed for their archetype.

Q. Are there any exceptions regarding the procedures just discussed for dispatch of short-term firm or long-term firm contracts?

A. Yes. Whether a wholesale contract is identified as long-term firm or short-term firm is entirely based on the length of its term. Consistent with previous treatment, the Company identifies long-term firm contracts by name and groups short-term firm contracts by general delivery points. If a short-term firm contract has flexibility as described for long-term firm contracts, it will be dispatched using the appropriate archetype. Conversely, if a long-term firm contract is a transaction for a standard block of energy, it will be dispatched the same way as standard short-term firm block transactions. Dispatched hourly contract energy takes are used in the Dispatch process to determine the energy requirements for thermal generation and system balancing transactions.

Reserve Requirement in Pre-dispatch

Q. Please describe the reserve requirement on the Company's system.

A. The North American Electric Reliability Council ("NERC") requires all companies with generation to carry operating reserves of 5 percent for operating hydro resources and 7 percent for operating thermal resources. One-half of these reserves must be spinning. Spinning reserves are the amount of capacity that can be ramped up in a 10-minute period. NERC and the Western Electricity Coordinating Council ("WECC") require companies with generation to carry spinning reserves to protect the WECC system from cascading loss of generation or transmission lines, uncontrolled separation and interruption of customer service.

Q. How does the model implement the operating reserve requirement?

A. The model calculates operating reserve requirements (both spinning and non-spinning) for the Company's east and west control areas, plus the regulating margin that is added to spinning reserve requirements. The total operating reserve requirement is 5 percent of dispatched hydro and 7 percent of committed available thermal resources for the hour, which includes both the Company's owned resources and the long-term firm purchase and sales contracts that contribute to the reserve requirement. Spinning reserve is one-half of the total reserve requirement plus the regulating margin, which is the same in nature as the spinning reserve but which is used for following changes in retail load from one hour to the next.

Q. How does the model satisfy reserve requirements?

A. Reserves are held first on hydro then on thermal units on a descending variable cost basis. Spinning reserve is satisfied before the non-spinning requirement. For each control area, the spinning reserve requirement is fulfilled using hydro resources and thermal units that are equipped with governor control. The non-spinning reserve requirement is fulfilled using remaining hydro reserves and thermal units. To better utilize the reserve capability of the Company's West-side hydro system, up to 175 MW of East-side reserves can be held in the West control region, of which 100 MW is spinning and 75 MW is non-spinning. The hourly reserve requirement allocated to the generating units is used in the Dispatch process to determine energy available from the resources and the level of the system balancing market transactions.

Q. What is the impact of reserve requirement on resource generating capability?

A. There is no impact on the hydro generation, since the amount of reserve allocated to hydro resources is based on the difference between their maximum technical capability and their available energy. However, if a thermal unit is designated to hold reserves, its hourly generation will be limited to no more than its capability minus the amount of reserves it is holding.

Model Inputs

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

A. As mentioned above, the inputs used in GRID include retail loads, thermal plant data, hydroelectric generation data, firm wholesale sales, firm wholesale purchases, firm wheeling expenses, system balancing wholesale sales and purchase market data, and transmission constraints.

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

A. The retail load represents the temperature-adjusted hourly firm retail load that the Company served within all of its jurisdictions for the twelve-month period ending March 31, 2003. The total company load is modeled based on the location of the load and transmission constraints between generation resources and load centers.

Q. Please describe the thermal plant inputs.

A. The amount of energy available from each thermal unit and the unit cost of the energy are needed to calculate net power costs. To determine the amount of energy available, the Company averages, for each unit, four years of historical outage rates and maintenance adjusted to remove extraordinary outages. The unit cost of energy for each unit is determined by using a four-year average of historical burn rate data. By using four-year averages for outages, maintenance 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 the 48 months ending March 2003. Other thermal plant data includes unit capacity, minimum generation level, minimum up and minimum down time, heat rate, fuel cost, and startup cost. The Company's use of a four-year average is consistent with the treatment the Company followed in its previous Washington rate case, Docket No. UE-991832.

Q. Did the Company's net power cost normalization use the Commission approved 40 year rolling average methodology?

A. Yes. The proposed net power costs were developed using the 40-year rolling average normalization method previously adopted by the Commission. This method uses input data based on stream flows for the period August 1948 through July 1988, as described below. The resulting generation is then normalized by running the production cost model for each of the forty different water years, producing forty sets of net power costs.

Q. Please describe the hydroelectric generation input data.

A. Forty years of monthly available hydroelectric generation for Company-owned hydro plants in the Northwest and Mid-Columbia purchased resources are input into the model. The Mid-Columbia hydro inputs are modeled with the Company's Vista hydro model. Data from Vista is based on actual stream flows for the period August 1948 through July 1988. Vista simulates the hydroelectric generation at the Mid-Columbia projects based on historical stream flows and current hydroelectric plant efficiencies, storage capabilities and requirements, minimum flow requirements (including fish requirements), regional loads and resources, and non-power operating constraints. The Company-owned Northwest hydro data inputs are a combination of actual generation for the period the plants were in service and estimated generation for the portion of the 40-year period that the plants were not in service.

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 is calculated as the actual average monthly hydroelectric generation for the years 1974 through March 2003. 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 and there is a lack of reliable data for the earlier years.

Q. Does the Company use other hydro generation inputs?

A. Yes. The Company also uses maximum and minimum capacities of the projects, must-run level, and monthly shapes of the available energy.

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

A. The data for firm wholesale sales and purchases are 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. Prices may be specifically stated, or may refer to a rate schedule, a market index such as California Oregon Border ("COB"), Mid-Columbia (Mid-C), South Path 15 ("SP15") or Palo Verde ("PV"), or be based on some type of formula. The long-term firm contracts are modeled individually, and the short-term firm contracts are grouped based on general delivery points. The contracts are dispatched against the hourly market prices so that they are optimized.

Q. Please describe the input data for wheeling expenses and transmission capability.

A. The data for firm wheeling are based on contracts to which the Company is a party. The firm transmission rights modeled in GRID are developed from the summer/winter postings on the Company's Open Access Same-Time Information System ("OASIS"). The limited additional transmission rights to which the Company may have access are based on the experience of the Company's Wholesale Energy Services Department.

Q. Please describe the system balancing wholesale sales and purchase input assumptions.

A. The GRID model uses three wholesale markets to balance and optimize the system. The three markets are at Mid-C, COB and Desert Southwest ("DSW"), where the model makes both system balancing sales and purchases if it is economical to do so under constraints. The input data regarding wholesale markets include market prices and sizes.

Q. What market prices are used in the net power cost calculation?

A. The market prices for the system balancing wholesale sales and purchases at Mid-C, COB, DSW, and SP15 are based on actual Dow Jones prices for the period January 2003 through May 2003 and the Company's monthly Official Price Forecast for the period June 2003 through December 2003 shaped into hourly prices. The market price hourly scalars are developed by the Company's Commercial and Trading Department based on historical hourly data since April 1996. Separate scalars are developed for on-peak and off-peak periods and for different market hubs to correspond to the categories of the monthly forward prices. Before the determination of the scalar, the historical hourly data are adjusted to synchronize the weekdays, weekends and holidays, and to remove extreme high and low historical prices. As adjusted, the scalars represent the expected relative hourly price to the price in a month. The hourly prices for the test period are then calculated as the product of the scalar for the hour and the corresponding monthly price.

Normalization

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

A. For historical test years, normalization is the process of modifying actual test year data by removing known abnormalities and making adjustments for known changes. Normalization produces test year results that are representative of expected conditions. The following are examples of the normalization of actual test period results:

1. Owned and purchased hydroelectric generation is normalized by running the production cost model for each of the forty different water years identified in the Hydro Regulation. The resultant forty sets of thermal generation, system balancing 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. As previously explained, normalized thermal availability is based on a four-year average.

2. Wholesale market prices are adjusted to reflect expected prices during the normalized period.
3. Long-term firm wholesale sales and purchase contracts are redispatched based on the normalized wholesale market prices and known changes in the contracts.
4. Wheeling expense is adjusted for known contractual changes.
5. System load net of special sales is adjusted to reflect loads that would have occurred under normal temperature conditions.

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 or purchase more from the market, thereby experiencing relatively high operating expenses. Conversely, under conditions of high stream flows, excess hydroelectric production may be used to reduce generation at the more expensive thermal electric plants, which in turn results in lower operating expenses for 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 have therefore 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. These variables are:

- Dispatch of firm wholesale sales and purchase contracts;
- Dispatch of hydroelectric generation;
- Reserve requirement, both spinning and non-spinning;
- Allocation of reserve requirement to generating units;
- The amount of thermal generation required; and
- System balancing wholesale sales and purchases.

Q. What reports does the study produce using the GRID model?

A. The major output from the GRID model is the Net Power Cost report. Interim data that can be exported for more detailed analyses is also available, the format for which can be hourly, daily, weekly, monthly, annually and by heavy load hours and light load hours.

Q. Do you believe that the GRID model appropriately reflects the Company's operating relationship in the environment in which it operates?

A. Yes. The GRID model appropriately simulates the operation of the Company's system over a variety of stream flow conditions consistent with the Company's operation of the system including operating constraints and requirements.

Q. Please explain your recommendation for the Aquila Hydro Hedge payment received by the Company.

A. In order to mitigate the negative effects of annual fluctuations of hydro conditions upon net power costs, the Company has entered into a contract (the "Aquila Hydro Hedge") with Aquila Risk Management Corporation ("Aquila") that provides financial protection when stream flow levels are low. The financial contract is structured as a collar, whereby PacifiCorp makes a payment to Aquila if stream flows are above a certain level (when power prices would tend to be low), and Aquila makes a payment to PacifiCorp if stream flows are below a certain level (when power prices would tend to be high). The Aquila Hydro Hedge is measured on a quarterly and October to September contract year basis. Any payments will be made on a quarterly basis based on actual stream flows for that quarter. Any payments received are held on the Company's balance sheet until a final determination for the contract year. For the just-completed contract year, the Company has booked a $5.2 million payment that it expects to receive from Aquila as a result of poor hydro conditions. Since the revenues pertain only to the just-completed contract year and are not ongoing, I have not included them in the net power cost study. Rather, I believe these revenues should be returned to customers through a balancing account. The balancing account treatment will be discussed in Mr. Griffith's testimony.

Q. Please describe Exhibit No.___(MTW-2).

A. This Exhibit is a schedule of the Company's major sources of energy supply by major source of supply for the test period, expressed in average megawatts owned and contracted for by the Company to meet system load requirements. The total shown on line 11 represents the total normalized usage of resources during the test period to serve system load. Line 12 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 13 represents the Company's System Load net of special sales.

Q. Please describe Exhibit No.___(MTW-3).

A. This Exhibit lists the major sources of normalized peak generation capability for the Company's winter and summer peak loads and the Company's energy load for the test period.

Prudence of Resource Acquisitions

Q. What requirement was imposed on the Company in its last Washington general rate case regarding the prudence of certain resource acquisitions?

A. In the Commission's Third Supplemental Order in Docket No. UE-991832, the Commission approved a stipulation that contained the following requirement:

> The Company will be required to make an affirmative showing in the direct testimony and exhibits of its next general rate proceeding demonstrating the prudence of those resources acquired since its general rate case (Cause No. U-86-02) which it proposes to include in rates in such proceeding.

Q. Have the resources acquired between 1986 and the date of the Third Supplemental Order undergone a prudence review process?

A. Yes. The participating parties in that rate proceeding (Staff, Public Counsel, and ICNU) were provided an opportunity to review the information provided by the Company that would comprise the Company's direct case as it relates to the acquisition of resources between the Company's 1986 and 1999 general rate cases. This review culminated in the Joint Report, a copy of which is included as Exhibit No.___(MTW-4).

Q. Which resources were addressed in the Joint Report?

A. The Joint Report addressed Craig and Hayden, Cholla Unit 4, the James River cogeneration project, the Hermiston cogeneration project, and the Foote Creek Wind Project. A description of the resources is included Exhibit No.___(MTW-4). Since the Company's 1999 general rate case the Company has acquired the Gadsby and West Valley resources. Mr. Tallman will address the prudence of the Gadsby and West Valley resources in his testimony.

Q. What was the conclusion of the Joint Report?

A. In the Joint Report, Staff concluded that the Company's acquisition of resources was consistent with increases in load and customer growth, and that the Company's decisions regarding the need to acquire new resources was guided by the Company's least-cost plan. Further, although Staff did not make a determination that the resources were acquired specifically to satisfy demand of Washington customers, Staff concluded that on a system-wide basis the resources were acquired prudently. Staff indicated that future proceedings could consider "whether these resources were acquired prudently to satisfy increased load growth or demand in Washington State, including consideration of the Company's commitments under merger agreements and orders, the impact of the 'inter-jurisdictional' allocation method used by the Company, and particular load-growth characteristics of the Company's Washington service territory." (Joint Report, p. 62)

Q. Why is it appropriate to review the prudence of the Company's resource acquisitions from a system-wide basis?

A. It makes sense to determine the prudence of resource acquisitions that support and benefit the Company's entire system from a system-wide basis. The Company operates a geographically dispersed system with characteristics that differ by location. In order to take advantage of those differences, the Company operates and plans its system on an integrated basis to capture the efficiencies of its system, which benefits all of the Company's customers by keeping net power costs as low as possible. Operating and planning the Company's system from the perspective of one State, in contrast, would lead to sub-optimal financial results for the Company and all of the Company's customers would pay higher costs. Accordingly, the prudence of the resource acquisitions should be analyzed from a total Company basis, not on the basis of a single State. Since the Joint Report found that resources were prudent from a system basis, the Commission has a sound basis for concluding that the acquisitions were prudent and therefore eligible for inclusion in Washington rates.

Q. How is the treatment of these resources affected by the "impact of the 'inter-jurisdictional' allocation used by the Company"?

A. The Company is proposing adoption of the MSP Protocol in this proceeding, as discussed in the testimony of Mr. MacRitchie. These resources are proposed to be treated in the manner provided in the MSP Protocol. The Protocol does not require that we demonstrate a "state-specific" benefit for particular resources before they can be recovered in a particular state's retail rates. Rather, resources are treated on a system-wide basis, and allocated among the states pursuant to the Protocol, which in the case of some resources takes into account the seasonal nature of the resource and any seasonality of a state's load. Thus, while the remainder of my testimony discusses some of the Washington-specific benefits of these resources, such a showing is not required under the MSP Protocol, but is being offered in response to the specific issues raised by Staff in the Joint Report.

Q. Have the Company's other jurisdictions included the resources addressed in the Joint Report in rates?

A. Yes. All of the Company's other jurisdictions have included these resources in rates, with the exception of Idaho, which has not had a general rate case either during or after the period of the resource acquisitions. While the adopted treatment of other jurisdictions is not binding on the Commission, it should be an indication that these resources have been found to be reasonable in cost and necessary to serve the Company's retail customers, including those in Washington.

Q. Was an expansion of PacifiCorp's system necessary to meet the requirements of the Company's Washington customers?

A. Yes. As shown on Exhibit No.___(MTW-5), the Company acquired 1,058 MW of net resources through 2002, and Washington's share of those resources is approximately 85 MW. It also shows that during the same period, Washington MWh sales increased by approximately 500 aMW. This demonstrates that Washington load growth contributed heavily to the need to add these resources, and that these "resources were acquired prudently to satisfy increased load growth in Washington state."

Q. Where are these resources located?

A. The acquired resources are split geographically between the Company's western and eastern control areas. Hermiston and James River are located in the western control area, while the remaining resources are located in or electrically connected to the eastern control area.

Q. Do resources on both the western and eastern sides of the Company's system benefit Washington customers?

A. Yes. As my following testimony discusses, resources on both sides of the Company's system benefit Washington customers in numerous ways. James River and Hermiston provide resource diversity and Hermiston also provides operational flexibility, which is beneficial to customers. Since the Company's portfolio of thermal resources is heavily weighted towards coal, both resources enhance the Company's resource diversity and lower the Company's fuel risk. The flexibility of Hermiston is derived from its gas contracts and the ability to dispatch the resource to match load requirements. Both projects also provide voltage support for the Company's transmission system.

Craig, Hayden and Cholla 4 resources benefit Washington customers because of peak diversity between the Company's eastern and western control areas. The Company's eastern control area is summer peaking and the western control area is winter peaking. This means that loads are higher in the eastern control during the summer season than during the winter season. On the other hand, the western control area is winter peaking so just the opposite is true. Since the entire system is operated on an integrated basis, resources that are not being fully utilized in the east are used to either serve customers in the western control area, make additional wholesale sales or displace higher cost generation. The monthly level of peak diversity during the test period is shown on Exhibit No.___(MTW-6).

Q. Have the eastern resource acquisitions also benefited Washington retail customers through the deferral of resource acquisitions?

A. Yes. The ability to more efficiently utilize resources as a result of peak diversity has allowed the Company to defer resource acquisitions that otherwise would have been required.

Q. Are eastern resources able to serve western control area customers only through seasonal diversity?

A. No. The operation of the Company's system on an integrated basis also allows eastern resources to serve western control area customers when western control area resources are not available due to poor hydro conditions and forced and planned outages, as long as these eastern resources are not being fully utilized.

Q. **Do Washington customers benefit from greater access to wholesale markets and a more efficient utilization of resources as a result of the acquisition of the eastern resources?**

A. Yes. As part of the Craig and Hayden and Cholla Unit 4 acquisitions, the Company also acquired additional transmission rights to and from wholesale markets. The Craig and Hayden transaction included 67 MW of on-peak and 100 MW of off-peak transmission rights to the Four Corners wholesale market. The Cholla Unit 4 acquisition included access to 350 MW of transmission rights in the APS control area. These additional transmission rights allow the Company to more efficiently utilize all of the Company's resources in both the eastern and western control area resources through expanded access to wholesale markets. The additional access enables the Company to make more and higher margin wholesale sales when resources are not fully utilized for retail customers and, when economic, the ability to displace higher priced resources when market purchase prices are lower. Both of these types of transactions benefit Washington retail customers by reducing net power costs. The expanded access to wholesale markets, benefits of seasonal diversity, and resource deferrals were the same factors giving rise to the benefits associated with Pacific Power's merger with Utah Power, a transaction that was found by the Commission to be in the public interest.

Q. Do the eastern control area resources provide other benefits?

A. Yes. The Craig and Hayden transactions include a seasonal exchange with Tristate that provides 50 MW of capacity during the winter season when the western control area is experiencing peak demand. Similarly, the Cholla transaction includes a seasonal exchange currently rated at 480 MW during the winter season. The addition of Craig, Hayden and Cholla further enhance the Company's system reliability and flexibility in maintenance scheduling and energy dispatching, which are beneficial to all of the Company's customers, including those in Washington.

In addition to supplying energy to customers from a renewable resource, Foote Creek is providing the Company with valuable knowledge and experience in operating wind projects that will assist future wind projects in the Northwest. Further, by adding renewable resources to the Company's resource portfolio, Foote Creek reduces the Company's reliance on less environmentally friendly resources, and by providing resource diversity, increases the reliability and security of our electricity supply.

Q. To what extent did the Company use the resources in question during the test period in this case?

A. The acquired resources are utilized extensively to meet the Company's resource requirements. In total, the resources addressed in the Joint Report provide approximately 8 million MWh of net generation to serve customers. For the reasons discussed above in my testimony, the Commission has a basis for determining that the resource acquisitions were prudent from both a system-wide and a Washington perspective.

Q. Please summarize your testimony regarding the prudence of the Company's acquisition of resources between 1986 and 1999.

A. Between 1986 and 1999, the Company acquired the following resources: Craig and Hayden, Cholla Unit 4, the James River Cogeneration Project, the Hermiston Cogeneration Project, and the Foote Creek Wind Project. These resource acquisitions were subjected to third-party verification and public review, including a thorough review by Staff in connection with the preparation of the Joint Report.. In the Joint Report, Staff concluded that the Company's acquisition of resources was consistent with increases in load and customer growth, that the Company's decisions regarding the need to acquire new resources was guided by the Company's least-cost plan, and that on a system-wide basis the resources were acquired prudently.

These resources provide system-wide benefits to the Company's customers by adding operational flexibility, reducing net power costs through seasonal diversity benefits and increased access to wholesale markets, and increasing reliability and security of the Company's electricity supply. These resources provide system-wide benefits; therefore, it makes sense to evaluate their prudence on a system-wide basis. At the same time, however, if evaluated from the perspective of whether they provide benefits to Washington, my testimony has shown the various benefits that these resources produce for the Company's Washington customers.

These resources have been added to the rate base in every State in which the Company has filed such a request. Staff has determined that the acquisition of these resources was prudent on a system-wide basis. Accordingly, the Company respectfully requests that the Commission include these resources in the Company's rate base in Washington.

Q. Does this conclude your direct testimony?

A. Yes.