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 600, 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. In addition, I represent the company on power resource and other various issues with intervenor and regulatory groups associated with the regulatory commissions in the six states in which the Company operates.

Summary of Testimony

Q. Will you please summarize your testimony?

A. I present the proposed pro forma normalized net power costs for the test period ended March 2006. In addition, my testimony:

- Describes the Company's production cost model, the Generation and Regulation Initiatives Decision Tools (GRID) model, which is used to calculate net power costs.

- Provides information on how input data is normalized in GRID and the rationale for doing so.
- Describes the company's west control area modeling used in this filing.
- Describes the change in hydro modeling associated with the VISTA hydro model.
- Presents the Company's proposed power cost adjustment mechanism (PCAM).
- Discusses the status of the company's filing to recover costs deferred for poor hydro conditions during 2005 and 2006.

Net Power Cost Results

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

A. The proposed net power costs are approximately $417 million for the Company's west control area.

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

A. In Docket No. UE-032065 – the last proceeding in which net power costs were determined in a Commission order – the Commission authorized the Company to recover net power costs of approximately $43.5 million in rates. In this proceeding, the Washington share of the company's west control area proposed net power costs is approximately $95.5 million. Those cost increases are due to a variety of factors which include the West Control Area (WCA) allocation methodology, the expiration of long-term firm wholesale sales and purchase power contracts, fuel cost increases for the Hermiston, Jim Bridger and Colstrip 4 thermal generating facilities, increased third-party wheeling costs and decreased hydro generation at Company-owned facilities and at Mid-Columbia resources from which the Company purchases power.

Q. Please explain why the WCA allocation methodology results in an increase in net power costs.

A. As an integrated system, the Company's resources are spread across its west and east control areas. Because of various requirements, including but not limited to the economic conditions and resource options prevalent at the time, resources are not built evenly geographically. One of the significant characteristics of the Company's resources on the west side is that the majority of the power transmitted in the west control area is through third-party wheeling contracts, versus through Company-owned facilities in the east control area. Under the allocation methodology used by the Company in Docket No. UE-032065, both fixed costs and wheeling expenses were allocated to all jurisdictions. However, as described in Mr. Wrigley's testimony, under the WCA method, only resources that are located in the Company's west control area are assigned to the west control area. Because of this, a smaller portion of the fixed transmission costs and a higher portion of third-party wheeling expenses are assigned to the west control area. The net effect of these changes resulted in relatively higher net power costs under the WCA method.

Q. Do you have some specific examples of cost increase that have occurred since Docket No. UE-032065?

A. Yes. The fuel price for the Jim Bridger plant has increased by approximately 33 percent. The wholesale market price of electricity at California Oregon Border (COB) and Mid-Columbia (Mid–C) has increased approximately 16 percent and 14 percent, respectively. The fuel price for Hermiston has increased approximately 15 percent. Washington retail loads have increased by approximately 205,000 MWh. Further, wholesale contracts such as the now-expired Puget Sound Energy wholesale sales contract, which were an offset to net power costs, have expired.

Q. Does the use of the WCA allocation method in this case mean that the Company will dispatch its system differently than it has historically?

A. No. The system will continue to be dispatched on an integrated basis for the benefit of the Company's customers. The WCA method will only be used to set Washington retail rates.

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.

Q. Are these proposed net power costs developed with the same production dispatch model used in the Company's last Washington filing?

A. Yes, with one exception. The Company's proposed net power costs were developed using release 6.1 of the GRID model. In the last Washington filing, the Company used GRID version 5.3. Compared to version 5.3, this version provides additional tools to make it easier to analyze model results.

New analysis features of note are:

- Provides an MMBtu report
- Provides finer granularity in LTC cost reporting

New graphic user interface features of note are:

- Replaced the Thermal Heat Rate data series with a timed attribute Heat Rate Coefficient data series

There are improvements in the calculation logic. However, the core calculation logic is the same. Calculation changes of note are:

- Provides greater precision in the commitment logic – *i.e.*, if the marginal unit's reference market is illiquid, GRID does not calculate a reserve credit.

Additionally, the new release provides enhanced security for projects with "locked" scenarios.

Q. With the exception of normal updates, are there any significant changes in the inputs to the model?

A. Yes, net power costs were modeled on a west control area basis instead of a Total Company system basis, which I describe in more detail later in my testimony.

Q. Please explain the west control area modeling of net power costs proposed in this case.

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 unless the transaction is tied to a specific east side resource such as Foote Creek.

West resources consist of:

- Jim Bridger and Colstrip 4 coal generation facilities,
- Hermiston combined cycle combustion turbine generation facility,
- Owned and contracted hydro 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 Merchant has acquired from PacifiCorp transmission. East-west control area exchanges and transfers between the west and the east are excluded.

Q. Did the Company adjust the capacity for Jim Bridger coal generation facility to reflect east control area use?

A. Yes. Bridger's capacity was reduced to 1300 MW for the June through October period and to 1367 MW for the remainder of the year to reflect firm transfer capabilities to the west control area.

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 various 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. Did you update the GRID model inputs from the Company's Results of Operations report that was prepared and filed with the Commission earlier this year?

A. Yes. Several updates have been made to reflect more current information. Short-term firm sales and purchases were updated to reflect additional transactions that were executed for the test period. Market prices for electricity and natural gas were updated to reflect the Company's August 2006 Official Forward Price Curve. Net system loads were adjusted to reflect the Yakama and Centralia load adjustments discussed by Mr. Wrigley. Coal prices were updated to reflect current cost expectations. The new Leaning Juniper wind project was included. The BPA summer/winter exchange contract was updated to reflect recent experience, and normalized hydro generation was updated to reflect more current information and the 40-year rolling average hydro normalization method approved by the Commission. The new purchase power contract with Roseburg Forest Products and the Northern California Power Authority energy exchange were also included.

Q. Please explain how GRID projects net power costs.

A. I have divided the description of the power cost model into three sections, as shown below:

- The model used to calculate net power costs.

- The model inputs.
- 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 is used 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 exported in Excel readable format, and
- A web browser-based user interface.

Based on requests by regulatory staffs and intervenors, the Company provides the model on a stand-alone personal computer.

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

A. West control area net power costs are calculated hourly 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) logic, based on resources, including contracts, from the pre-dispatch logic:
    - Optimal thermal generation levels, and fuel expenses
    - Expenses (revenues) from firm purchase (sales) contracts
    - System balancing market purchases and sales necessary to balance and optimize the west control area and net power costs taking into account the constraints of the west control area
    - Expenses for purchasing additional transmission capability
4. Model outputs are used to calculate net power costs on a total west control area 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 logic is a linear program (LP) optimization module, which determines how the available thermal resources should be dispatched given load requirements, transmission constraints and market conditions, and whether market purchases (sales) should be made to balance the west control area. 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 logic provide thermal availability and system energy requirements for the Dispatch logic?

A. Yes. Pre-dispatch, which occurs before the Dispatch logic, calculates the availability of thermal generation, dispatches hydro generation, schedules firm wholesale contracts, and determines the reserve requirement of the Company's west control area. In my following testimony, I'll describe each of these 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 logic 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 or down in a short period of time. The commitment status of a unit indicates whether it is economical to bring that unit on line in that particular hour. The availability of thermal units and their commitment status are used in the Dispatch logic 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 logic, the Company's available hydro generation from each non-run of river project is shaped and dispatched by hour within each week in order to maximize usage during peak load hours. The weekly shape of a non-run of river project is based on the net system load. The dispatch logic incorporates minimum and maximum flow for the project to account for hydro license 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 logic to determine energy requirements for thermal generation and system balancing transactions.

Wholesale Contracts in Pre-Dispatch

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

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 and intermediate-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 archetypes based on contract terms:

- Energy Limited (shape to price or load): The energy take of these contracts have minimum and maximum load factors. The complexities can include shaping (hourly, annual), exchange agreements, and call/put optionality.

- Generator Flat (or Fixed Pattern): The energy take of these contracts is tied to specific generators and is usually the same in all hours, which takes into consideration plant down time. There is no optionality in these contracts.
- Fixed Pattern: These contracts have a fixed energy take in all hours of a period.
- Complex: The energy take of one component of a complex contract is tied to the energy take of another component in the contract or the load and resource balances of the contract counter party.
- Contracted Reserves: These contracts do not take energy. The available capacity is used in the operating reserve calculation.
- Financial: These contracts are place holders for capturing fixed cost or revenue. They do not take energy.

In the Pre-dispatch logic, 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 is entirely based on the length of its term. Consistent with previous treatment, the Company identifies contracts with terms greater than one year by name. Short-term firm contracts are grouped by delivery point. If a short-term firm contract has flexibility as described for long-term firm contracts, it will be dispatched using the appropriate archetype and listed individually with the long-term contracts. Hourly contract energy dispatch is used in the Dispatch logic to determine the requirements for thermal generation and system balancing transactions.

Reserve Requirement in Pre-Dispatch

Q. Please describe the reserve requirement for the Company's west control area.

A. The Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC) set the standards for reserves. All companies with generation are required to maintain Operating Reserves, which comprise two components – Regulating Reserve and Contingency Reserve. The Company must carry contingency reserves to meet its most severe single contingency (MSSC) or 5 percent for operating hydro and wind resources and 7 percent for operating thermal resources, whichever is greater. A minimum of one-half of these reserves must be spinning. Units that hold spinning reserves are units that are under control of the control area. The remainder (ready reserves) must be available within a 10-minute period. NERC and 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.

Regulating Reserve is an amount of Spinning Reserve immediately responsive to automatic generation control (AGC) to provide sufficient regulating margin to allow the control area to meet NERC's Control Performance Criteria.

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

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

Q. How does the model satisfy reserve requirements?

A. Reserves are met first with unused hydro capability, then by backing down thermal units on a descending variable cost basis. Spinning reserve is satisfied before the ready reserve requirement. For the west control area, spinning reserve requirement is fulfilled using hydro resources and thermal units that are equipped with governor control. The ready reserve requirement is met using purchase contracts for operating reserves, the remaining unused hydro capability, and by backing down thermal units. The allocated hourly operating reserve requirement to the generating units is used in the Dispatch logic to determine the 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 hydro generation, since the amount of reserves allocated to hydro resources is based on the difference between their maximum dependable capability and the dispatched 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.

GRID Model Inputs

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

A. As mentioned above, 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 forecasted hourly firm retail load that the Company serves within all of its west control area jurisdictions for the twelve-month test period ending March 31, 2006. This load is modeled based on the location of the load and transmission constraints between generation resources to 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. The heat rate for each unit is determined by using a four-year average of historical burn rate data. By using four-year averages to calculate outages, maintenance and heat rate data, annual fluctuations in unit operation and performance are smoothed. The four-year average approach has been used in rate case filings for over 10 years. For this particular filing, the 48-month period ending March 2006 is used. Other thermal plant data includes unit capacity, minimum generation level, minimum up/down time, fuel cost, and startup cost.

Q. Please describe the hydroelectric generation input data.

A. The Company's hydro normalization is based on a rolling 40-year average of the most recent information available. The relevant data are as follows

- Owned west side hydro water years 1964-2003;
- Mid-Columbia contracts water years 1964-1988 with 1989 -2003 mapped as described below; and
- Small hydro using available data – starting in 1982 to 2003 with 1964 - 1982 mapped as described below.

For the years where the historical data did not overlap with the 40-year period ending in 2003, the Company selected the generation from a year in the historical record where the stream flow statistically matched the stream flow of the missing year. The Company used its hydro regulation model (VISTA) to shape individual water years against the Company's official prices forecast (applicable to projects with storage). The VISTA model is described in a separate section of my testimony.

Q. Does the Company use other hydro generation inputs?

A. Yes. Other parameters for the hydro generation logic include the maximum capability, the minimum run requirements, ramping restrictions, shaping capability, and reserve carrying capability of the projects.

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

A. The data for firm wholesale sales and purchases are based on west control area contracts to which the Company is a party. Each contract specifies the basis for 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 also be specifically stated, may refer to a rate schedule, a market index such as COB or Mid-C, or may 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 with flexibility are dispatched against the hourly market prices so that they are optimized from the point of view of the holder of the call/put.

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

A. Firm wheeling expense is based on the historic period's wheeling expense adjusted for known contract changes in the pro forma period.

Firm transmission rights between transmission areas in the GRID west control area topology are based on PacifiCorp's Merchant Function contracts with PacifiCorp's Transmission Function and contracts with other parties.

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

A. The GRID model uses two liquid market points to balance and optimize the west control area. The two wholesale markets are at Mid-C and COB. Subject to the constraints of the system and the economics of potential transactions, the model makes system balancing sales and purchases in addition to optimization transactions at these markets. The input data regarding wholesale markets include market price and market size.

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 two liquid markets are from the Company's official monthly forward price forecast as of August 31, 2006 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 such, the scalars represent the expected relative hourly price to the average price forecast for 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 historic test years.

A. For historic test years, retail load, thermal availability, and hydro generation are normalized. The actual retail load from the historic test period is temperature normalized pursuant to the Commission-adopted methodology as described by Mr. Wrigley. As previously explained, normalized thermal availability is based on a four-year average. Owned and purchased hydroelectric generation is normalized by running the production cost model for each of the 40 different sets of hydro generation. The resultant 40 sets of thermal generation, system balancing sales and purchases, and hydroelectric generation are then averaged.

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 normalization.

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, is 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 analyses that simulate the operation of the entire system using historical water conditions, as being representative of what can reasonably be expected to occur.

VISTA Model

Q. What is the VISTA model?

A. The Company uses the VISTA Decision Support System (DSS) developed by Synexus Global of Niagara Falls, Canada as its hydro optimization model. The VISTA model is designed to maximize the value of the hydroelectric resources for ratemaking purposes by optimizing the operation of hydroelectric facilities against a projected stream of market prices. VISTA uses an hourly linear program to define the system configuration and the environmental, political, and biological requirements for that system. The input to the VISTA model is historical stream flow data, plant/storage characteristics, license requirements, and market prices. The output of the VISTA model is the expected generation subject to the constraints described above.

Q. Does the Company use the VISTA model in other jurisdictions?

A. Yes. Based on the need for more current hydro information and the Company's experience with the VISTA model, the Company is using or has used the VISTA model as follows:

- Utah general rate cases – Docket Nos. 04-035-42 and 06-035-21
- Oregon general rate cases – Docket Nos. UE-170 and UE 179
- Idaho general rate case – Docket No. PAC-E-05-1
- California general rate case – Docket No A05-11-022
- Wyoming general rate case – Docket No 20000-230-ER-05

Q. Does the Company's use of the VISTA model in this general rate case differ from its use in other Company activities?

A. No, with one exception. The west control area physical project data, constraint description, and historical stream flows used in the VISTA model in the preparation of hydro generation used in this filling are exactly the same data used by the Company's Operations Planning Group for short term planning, the Company's Integrated Resource Planning process, and the filings listed above. For this filing, additional procedures were required to comply with Commission precedent requiring use of a 40-year rolling average. Those procedures are described later in my testimony.

Q. Do other utilities use the VISTA DSS model?

A. Yes. The VISTA DSS model is used by a growing number of other energy companies including the Bonneville Power Administration.

Q. Please describe the VISTA model inputs.

A. The VISTA input data come from a variety of sources, which are separated into the following three groups – Company-owned plants without operable storage, Company-owned plants with operable storage, and Mid-Columbia contracts.

The Company owns a large number of small hydroelectric plants scattered across the west control area. These projects have no appreciable storage ponds and are operated as Run-of-River projects; *i.e.*, flow in equals flow out. For these plants "normalized generation" is based on a statistical evaluation of historical generation adjusted for scheduled maintenance.

The Company's larger projects (Lewis River, Klamath River, and Umpqua River) have a range of possible generation that can be modified operationally by effective use of storage reservoirs. For these projects, the Company feeds the historical stream flow data through its optimization model, VISTA, to create a set of generation possibilities that reflect the current capability of the physical plant, the operating requirements of the current license agreements, as well as the current energy market price projections.

For the Lewis and Klamath Rivers, the stream flows used as inputs to the VISTA model are the flows that have been recorded by the Company at each of the projects. In most cases the flows, using a very simple continuity of water equation where Inflow = Outflow + Change in Storage, are used to develop generation levels.

For the Umpqua River, the inflow data was reconstructed by piecing together a variety of historical data sources. The USGS gauge data at Copeland (the outflow of the entire project) was used to true up the previously recorded flows developed using the continuity equation described above.

The Company's Mid-Columbia energy is determined by using VISTA to optimize the operations of the of the six hydro electric facilities below Chief

Joseph under 70 years of "modified" stream flow conditions. The modified hydro flows are the flows developed as the "PNCA Headwater Payments Regulation 2004-05" file, also known as "The 2005 70 year Reg" file, completed in July 30, 2004 for hydro conditions that actually occurred for the period 1928 through 1997. Thus the inflows to the Mid-Columbia projects are the result of extensive modeling that reflects the current operations and constraints of the Columbia River. These stream flow data are the most current information available to the Company and serve as an input to the VISTA model. As in the case of the Company's large plants, the energy production resulting from the set of stream flows is analyzed statistically to produce a set of probability curves or exceedence levels for each group/week.

In the above processes VISTA works on five groups of hours within a week. The results are defined as exceedence level statistics for each week.

Q. Please describe the VISTA model's output.

A. The VISTA model calculates the probability of achieving a level of generation. The model output is expressed in terms of "exceedence" levels. Each exceedence level represents the probability of generation exceeding a given level of generation. The number of output exceedence levels is an input parameter. For example, the user can ask for a set of three exceedence levels – 25 representing a wet condition, 50 representing the median condition, and 75 representing a dry condition. The 25-50-75 exceedence levels are the typical output that the Company's Operations Planning Group uses in its studies.

Q. What VISTA output did the Company use in this filing?

A. As stated earlier, the Company's filing, which uses a 40-year rolling average is consistent with the Commission precedent from Docket No. UE-921262. To accomplish this, the Company ran the VISTA model forty times with a single year's historic conditions versus running the VISTA model with a complete set of hydro conditions. For example, the Lewis River 1964 stream flow data was input into the VISTA model. The VISTA model shaped that stream flow into weekly energy/capacity availability subject to parameters described earlier. This process is performed 40 times for the Mid-Columbia contracts, 40 times for the large Company-owned projects, and 40 times for the small Company-owned projects. As stated earlier in the description of the hydroelectric generation input data, the 40 sets of VISTA output are the hydro inputs to the GRID model.

GRID 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;
- Operating Reserve requirement, both contingent (spinning and ready) and regulating;
- Allocation of operating reserve requirement to generating units;
- The amount of thermal generation required; and
- System balancing wholesale sales and purchases and optimization transactions.

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

A. Yes. The GRID model appropriately simulates the operation of the Company's west control area on a stand-alone basis over a variety of stream flow conditions consistent with the Company's operating constraints and requirements.

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, expressed in average megawatts owned and contracted for by the Company to meet west control area load requirements, for the pro forma period. The total shown on line 11 represents the total future usage of resources during the pro forma period to serve west control area load. Line 12 consists of wholesales 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._____(MTW-3).

A. This Exhibit lists the major sources of future 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.

PCAM

Q. Has the Company previously requested a PCAM in a Commission proceeding?

A. Yes. The Company formally requested a mechanism in Docket No. 050684. In its decision, the Commission stated:

> In sum, we reject the proposed PCAM for three reasons: 1) the mechanism should focus on short-term costs subject to market price volatility or other extraordinary events that a beyond the company's control, and should not include costs for new generation; 2) The 90/10 sharing band and the absence of a deadband do not adequately balance risks and benefits between shareholders and ratepayers, and; 3) An acceptable allocation methodology is a prerequisite to establishing a PCAM.

The Commission further stated that:

> We encourage the Company to work with Staff and intervenors to develop a PCAM in line with the discussion above. Following discussions with Staff and intervenors, the company may submit a revised PCAM proposal ………..

Q. Has the Company addressed the concerns raised by the Commission and had discussions with Staff and intervenors?

A. Yes. The Company designed the proposed PCAM so that it would address the concerns raised by the Commission. The Company has also had discussions with Staff and intervenors regarding the design of the PCAM.

Q. Please provide some background on why the Company is requesting a PCAM in this proceeding.

A. We are requesting a PCAM to protect the Company and customers from the net power cost volatility related to the west control area. This volatility has been due in large part to the generation volatility of owned and contracted hydro generation. For the test period, normalized hydro generation produces 17.9 percent of the Company's west control area load requirement. Of course, other factors such as market price volatility, weather conditions, forced outages for generation and transmission facilities, planned outages and the economy also affect the volatility of net power costs.

Q. Please explain the information shown on Exhibit No.___(MTW- 4).

A. Exhibit No.___(MTW-4) shows the historical west control area hydro generation from 1990 through 2005. As shown, actual hydro generation varied significantly and ranged between 4.15 million and 7.83 million MWh over that period.

Q. Are the factors which drive net power cost volatility controllable by the Company?

A. No. While the potential causes of net power cost volatility have always been present, the cost of addressing these factors has increased dramatically. Based on 2005 market prices at the Mid-C wholesale market hub and the hydro generation difference shown in Exhibit No. ___(MTW-4), net power costs could swing by $215 million for the west control area hydro generation volatility, notwithstanding wholesale market price changes associated with extreme conditions and other factors that cause volatility. Historical market prices are shown in Exhibit No.___(MTW-5).

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

A. Wholesale market prices are expected to increase over 2006 levels before they begin a slight decline that continues through 2013/2014, when they begin a gradual increase. However, it is worth noting that the expected level of volatility is quite high over a substantial portion of this period, which demonstrates the need for a PCAM to capture the impacts of this volatility. Exhibit No.___(MTW-6) is the Company's Official Price Projection of future market prices.

Q. Has the Commission recognized the issue of net power cost volatility and the associated need for power cost recovery mechanisms?

A. Yes. Both Puget Sound Energy and Avista have power cost recovery mechanisms. The variable net power cost portion of the Company's proposed mechanism is very similar to Avista's recently approved mechanism.

PCAM Structure

Q. Please provide a summary description of the Company's proposed PCAM.

A. The PCAM is an incentive-based mechanism that would share variations in the sum of adjusted actual variable net power costs and actual fixed production costs from the sum of authorized variable net power costs and fixed production costs in rates. The costs would be subject to a symmetrical deadband of plus or minus $3.0 million and sharing bands from greater than plus or minus $3.0 million to $7.4 million and greater than plus or minus $7.4 million, all on a Washington basis. The Company would bear all cost variances within the deadband. Costs that fall within the first sharing band would be split 60%/40% between customers and Company and costs that fall within the second sharing band would be shared 90%/10% between customers and Company.

Q. How did the Company derive the proposed deadband and sharing bands?

A. The Company designed the deadband and sharing bands to provide a reasonable amount of sharing as directed by the Commission. The proposed deadband and sharing bands on average produce approximately a fifty/fifty sharing on Western Control AREA variances up to $100 million. Therefore, risks and benefits will be adequately shared. It should also be noted that the deadband and sharing bands are consistent with those recently adopted in the power cost recovery mechanism currently in place for the Company in Wyoming.

Q. Are the proposed deadband and sharing bands similar to those recently adopted for Avista's Energy Recovery Mechanism (ERM)?

A. Yes. The deadband and sharing bands are consistent with those adopted for the ERM based on the ratio of deadband and sharing bands as a percent of Washington retail revenues.

Q. Please define authorized variable net power costs.

A. For the PCAM deferral calculation, authorized variable net power costs will be defined as the Washington-allocated sum of purchased power costs, fuel expense, wheeling expense and brokerage fees paid to third party brokers who facilitate the sale and purchase of energy and natural gas, less wholesale sales of electricity and natural gas and transmission revenues included in FERC Account 456. The measurement period will be each calendar year. The variable net power costs in rates will be in effect until the Company's rates are adjusted through a general rate case.

Q. Please define "adjusted actual" variable net power costs for the PCAM calculation.

A. In order to meet the Commission's directive to include only short-term costs subject to market price volatility or other extraordinary costs beyond the Company's control and to exclude new generation, the Company proposes to develop actual costs by updating authorized net power costs for data inputs consistent with the Commission directive and rerunning GRID to develop adjusted actual costs. The Company proposes to update the following data inputs: actual market prices for electricity and natural gas, fuel costs, hydro generation, retail loads, forced outages, planned maintenance and new wholesale transactions that pass the exclusion requirement discussed below in my testimony. This mechanical approach will limit updated costs that are included in actuals and will reduce potential controversy. Adjusted actual net power costs will be further adjusted by subtracting wheeling revenue included in FERC Account 456 to derive adjusted actual variable net power costs.

Q. Does the proposed PCAM include an adjustment for variances in Washington retail sales?

A. Yes. The proposed PCAM includes a monthly adjustment for the retail revenue impact of changes in Washington retail sales from the level included in rates. The adjustment is calculated by multiplying the portion of the retail rate related to the production and transmission revenue requirement by the change in retail sales. Increased retail revenue related to sales increases would be netted against increased net power costs and, conversely, revenue decreases related to declines in sales would be netted against decreased net power costs. This adjustment is the same as the "retail revenue adjustment" feature of Avista's ERM.

Q. Are new long-term resource costs or wholesale sales includable in the PCAM deferral calculation?

A. No. Any new power contract, extension or renewal of an existing power contract, or new resource with a term or life greater than two years and are larger than 50 aMW, will be excluded from adjusted actual costs until such costs are included in base rates in a general rate case. The energy and cost of meeting load requirements that would have been met by the new contract(s) or resource(s) will be captured through wholesale market system balancing transactions at Mid-C and COB calculated by the GRID model. The energy price will be based on the actual COB and Mid-C market prices included in GRID. New contract and resource costs up to 50 aMW are exempt from this limitation.

Q. Please explain the fixed production cost component of the PCAM.

A. This component measures the Washington-allocated annual variance between the fixed production costs in rates and the actual fixed production costs during the measurement period. Fixed production costs are the sum of revenue requirements for west control area production and transmission plant. For the purpose of this calculation, the revenue requirement is the sum of operation and maintenance expense, depreciation and amortization expenses plus authorized pre-tax return on the net plant. The net plant is a 13-month average. The fixed production cost component is included to provide a match between variable net power costs and fixed production costs for recovery.

Q. Please explain the treatment of major plant outages.

A. For recovery of fixed costs associated with the Hermiston, Jim Bridger and

Colstrip 4 generating plants, when a plant fails to meet a 70 percent availability factor during the measurement period, the Company must demonstrate that: 1) the fixed costs set in rates were in fact incurred for the time the plants had an outage that reduced the availability factor below 70 percent; and 2) the outage was not the result of imprudent actions on the part of the Company. As explained above, the fixed costs for each plant include the pre-tax return on the net plant, depreciation expense and operation and maintenance expense not included in variable net power costs. If the actual fixed costs are below the level in rates, or the outage was the result of imprudent actions and some costs are disallowed, those disallowed costs will be excluded from actual costs in the fixed cost component. No adjustment will be made to the normal method of calculating the retail revenue credit for retail sales variations.

Q. Will the fixed production cost component be calculated on a monthly basis like the variable net power cost component?

A. No. The variable net power cost component will be calculated monthly to meet accounting requirements. The fixed cost component will be calculated only at the end of each measurement period to reduce administrative burden.

Q. Please explain Exhibit No. ___(MTW-7).

A. Exhibit No. ___ (MTW-7) is a simple illustration of the Company's proposed PCAM deferral calculation. As shown, each month the authorized variable net power costs in rates is allocated to Washington and then divided by Washington retail load in rates to convert the amount in rates to a $/MWh basis. The same calculation is also performed for the adjusted actual net power costs. The difference between authorized variable net power costs in rates and adjusted actual net power costs on a $/MWh basis is then multiplied by the Washington retail load in rates to determine the amount that is subject to the treatment of the deadband and sharing bands to calculate the monthly deferral. This calculation occurs each month of the measurement period to determine the deferral for variable net power costs. The cost deferral associated with the difference between fixed production costs in rates and actual fixed production costs is calculated in the same manner as the variable net power cost component, except it is calculated only once per year at the end of each measurement period. The PCAM deferred balance is the sum of deferred balances for the variable net power cost and fixed production cost components.

Q. Does the deferred balance accrue interest?

A. Yes. The deferred balance less accumulated deferred income taxes will accrue interest at the Company's actual cost of debt as updated semi-annually.

Q. How often will the Company request recovery of or return of accrued balances to customers?

A. The Company will make a filing on an annual basis for review of deferred balances, so that review of the deferred calculation does not accumulate into an extremely large amount of processing workload for a future period. Recovery of or return of deferred balances to customers should occur on an annual basis, as long as a plus or minus $3 million balance threshold has been exceeded at the end of the measurement period. If the balance is less than the threshold, it will continue to accrue interest until the end of the next measurement period, when the balance will be compared to the threshold again. This process will continue until the threshold is exceeded. This will reduce the frequency of rate changes during periods of lesser cost volatility but still provide proper price signals to customers.

Q. Should accrued costs be subject to a review?

A. Yes. Cost and revenue changes related to data updates included in the adjusted actual net power cost calculation and the deferral calculation should be subject to review.

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

A. Mr. Griffith's testimony describes the Company's proposal.

Hydro Deferral

Q. When does the company expect to file for recovery of costs deferred during 2005 and 2006 for poor hydro conditions?

A. Once the Company receives approval of an allocation methodology, it will determine how best to proceed with respect to amortization of hydro deferrals.

Q. Does this conclude your direct testimony?

A. Yes.