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 800, Portland, Oregon 97232, and my present title is Director, 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 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 six state regulatory commissions to whose jurisdiction we are subject.

Summary of Testimony

Q. Will you please summarize your testimony?

A. I present the proposed pro forma normalized net power costs for the September 2004 test period. 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 change in hydro modeling associated with the VISTA hydro model.
- Provides quantitative analysis of the Company's historical net power cost exposure and how that relationship has changed to the point that the exposure has become very asymmetrical.
- Presents the Company's proposed power cost adjustment mechanism (PCAM) which, if adopted, would restore the net power cost exposure borne by the Company to historical levels.

Net Power Cost Results

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

A. The proposed net power costs are approximately $830 million Total Company. In comparison, actual results for the twelve-month period ending February 2005 are approximately $754 million.

Q. How do these compare with the level currently included in rates?

A. Net power costs are approximately $296 million higher than the $534 million included in base rates in Docket No. UE-032065, the Company's most recent Washington general rate case. The approximate cost increases, on a system basis, for the major cost categories are:

- A 4.1 million MWh increase in net system load increases net power costs by $246 million. This cost increase is partially offset by the cost decreases associated with the new resources that were acquired to serve the load increase.

- Expired long term power contracts increases net power costs by $30 million.
- Changes in fuel prices and market prices increase net power costs by $61 million.
- Changes in hydro availability, as discussed later in my testimony, increase net power costs by $11 million.

The cost increases are offset by the following cost decreases:

- New long term power contracts lowers net power costs by $28 million.
- The Currant Creek project lowers net power costs by approximately $28 million in the pro forma period.

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

A. In Docket No. UE-032065, the Commission authorized the Company to recover net power costs of approximately $44.7 million in rates. The Washington share of the Company's proposed net power costs is approximately $70.1 million, or a $25.4 million increase. Included within the $25 million increase are $1 million of Washington QF costs that are assigned directly to Washington, as described in the testimony of Mr. Taylor.

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 5.1 of the GRID model. In the last Washington filing, the Company used GRID version 2.0. There were three other releases between 2.0 and 5.1. Compared to version 2.0, this version provides additional tools to make it easier to create and compare scenarios. New analysis features of note are:

- The capability of copying resources between projects.
- A new report that compares inputs between two scenarios.
- An additional diagnostic report for the hydro inputs.
- Protection locks on a scenario, its input and its outputs.

New graphic user interface features of note are:

- Market caps hourly data series converted to a time dependent data series.
- Multiple topology versions within a project.
- Escalation filters for hourly data series.
- The monthly hydro data series is now a weekly hydro data series and is compatible with the output format of the Company's hydro regulation model (VISTA).

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

- The shape-to-load algorithms were replaced with a peak shaving algorithm that provides greater precision in following the net system load.
- The maximum hydro capability is now tied to the individual hydro

condition versus having one value serve all hydro conditions.

- Some inputs previously manually calculated are now calculated within the model, e.g. incremental heat rate values, marginal resource credit.
- A quick start credit for uncommitted peaking units is now part of the GRID operating reserve logic.

Additionally, there were upgrades to the GRID infrastructure for more efficient processing.

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

A. Yes, there is a change to the methodology for developing the hydro inputs, which I describe in more detail later in my testimony.

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

A. Consistent with the method historically followed in Puget Sound Energy's rate proceedings, the Company made certain forward-looking adjustments to the test year ended September 30, 2004 power cost data. The effect of these adjustments was to develop projected net power costs for the rate effective period ending March 31, 2007. These results are then adjusted to the test period by multiplying the projected net power costs by 92.8 percent, the production adjustment factor. This adjustment factor represents the ratio of weather-normalized energy loads delivered for the test period to the rate effective period, and essentially scales back rate year power costs to correspond to test year loads. 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 under a variety of streamflow conditions. The results obtained from the various streamflow conditions are averaged and the appropriate cost data is applied to determine an expected net power cost under normal streamflow and weather conditions for the test period.

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
- 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. 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 system and 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 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 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 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 system. 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 online 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: 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.
- Flat (or Fixed): 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.

- No-Energy (or 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 system.

A. The Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC) sets 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 East and West control areas. 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 each 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, uncommitted quick start units, 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 an "uncommitted quick start unit"?

A. As noted above, ready reserves must be available within a 10-minute period. A quick start unit is a unit that can be synchronized with the transmission grid and can be at capacity within the 10-minute requirement. If a gas supply is available and the units are not otherwise dispatched, one Gadsby CT unit and the five leased West Valley units meet this requirement.

Q. Are the operating reserves for the two control areas independent of each other?

A. Yes, with one exception for spinning reserves and one exception for ready reserves. The dynamic overlay component of the Revised Transmission Services Agreement with Idaho Power allows the Company to utilize the reserve capability of the Company's West side hydro system in the east side control area. Up to 100 MW of East control area spinning reserves can be met from resources in the West control area.

If the Company leaves transmission open between the East control area and the West control area, ready reserves may be held in the West control area for the East control area. The model inputs specify that 100 MW of the Path “C” capability is left open and 100 MW of East side ready reserves is carried in the West side. The premise is: the West control area can call upon 100 MW of its reserve and 100 MW of Jim Bridger generation can be rescheduled to Path “C” within the ten-minute widow to qualify for ready reserve.

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 are 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 jurisdictions for the twelve-month pro forma period ending March 31, 2007. 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 September 2004 is used. Other thermal plant data includes unit capacity, minimum generation level, minimum up/down time, fuel cost, and startup cost.

Q. Are there any exceptions to the four-year average calculation?

A. Yes. Some plants have not been in service for the entire four year period. For those plants, the Company uses the manufacturer's expected value for the missing months to produce a weighted average value of the known and theoretical rates.

Q. Please describe the hydroelectric generation input data.

A. The Company's hydro normalization is based on a 40-year average. The relevant data is as follows:

- Owned west side hydro water years 1962-2001;
- Mid-Columbia contracts water years 1949-1988;
- Bear River and small hydro using what is available – starting in 1982, balance filled in with average of available to bring to 40 years; and

- Aligned common years e.g. 1962-1988 for owned west side and Mid-Columbia, 1982-1988 for Bear River.

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 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 California Oregon Border (COB), Mid-Columbia (Mid-C) or Palo Verde (PV), 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 topology are based on PacifiCorp's Merchant Function contracts with PacifiCorp's Transmission Function and contracts with other parties. The limited additional transmission that the Company may have access to is based on the experience of the Company's Commercial and Trading Department – example: the day ahead firm transmission that the Company historically purchases on Path "C."

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

A. The GRID model uses five liquid market points to balance and optimize the system. The five wholesale markets are at Mid-C, COB, SP15, Four Corners, and PV. Subject to the constraints of the system and the economics of potential transactions, the model makes both system balancing sales and purchases 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 five liquid markets are from the Company's monthly forward price forecast as of December 30, 2004 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. 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 streamflows 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 streamflows, 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. As stated earlier, the Company is using a new hydro regulation model. 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 streamflow 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. Why did the Company switch to the VISTA model for hydro generation normalization?

A. As far back as the mid-1970's, PacifiCorp and other utilities in the Northwest have used regional historical streamflow records provided by the Bonneville Power Administration (BPA) to normalize expected hydro generation. BPA adjusted the historical streamflow data for changes in the river system (*e.g.*, new projects), the license requirements (*e.g.*, fish flush), and the environment (*e.g.*, more surface runoff). The Company started with 40 years of adjusted historical data (water-years 1929 to 1968). In the mid-1980s, BPA added a block of ten years to the adjusted numbers.

In the 1990s, when circumstances required BPA to be more competitive, BPA stopped sharing and/or preparing the regional information. The only information available was the data made public during the BPA rate case process. Without BPA maintaining the regional hydro information, the hydro data the Company used in prior general rate cases became stale.

For Company-owned projects, the Company has been using the 50 water-year set of hydro generation based on a BPA West Group Forecast Regulation (circa 1986). For the Mid-Columbia projects, the Company used data from the 1999 BPA White Book generation forecast for water-years 1929 to 1978.

In 2003, the Company used hydro generation developed by the VISTA model in its Integrated Resource Plan (IRP). In the spring of 2004, the Company began using the VISTA model to develop hydro forecasts for its short term planning.

Q. Has the Company used 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 case (Docket No. 04-035-42)
- Oregon general rate case (Docket No. UE170, currently pending)
- Idaho general rate case (Docket No. PAC-E-05-1, currently pending)

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 physical project data, constraint description, and historical streamflows used in the VISTA model in the preparation of hydro generation proposed for use in this filing 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. The VISTA DSS model is used by a growing number of other energy companies including the Bonneville Power Administration.

Q. In previous cases, hydroelectric generation was normalized by using historical water data. Is that still true with the VISTA model?

A. Yes. The period of historical data varies by plant. As explained later in my testimony, the Mid-Columbia projects use sixty adjusted water years beginning with water year 1928/29. The Company's large plant data begins in the 1958-1963 range. The Company's small plant data begins in the 1978-1989 range. Later in my testimony, I explain how the different historical data is used to meet the Commission-directed 40-year rolling average.

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 its system. 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 streamflow 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 streamflows 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 60 years of "modified" streamflow conditions. The modified hydro flows are the flows developed as the "PNCA Headwater Payments Regulation 2002" file, also known as "The 2002 60 year Reg" file, completed in February 2003 for hydro conditions that actually occurred for the period 1928 through 1988. 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 streamflow 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 streamflows 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. Is the input of hydro generation located outside of the Northwest modeled in the same manner as the Pacific Northwest hydro generation?

A. Yes. Using the VISTA model, the input of hydro generation located in Utah and Southeast Idaho are calculated in the same manner as the Pacific Northwest hydro generation.

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 is consistent with the Commission precedent from Docket No. UE-921262 to use a 40-year rolling average. 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 1962 streamflow data was input into the VISTA model. The VISTA model shaped that streamflow 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 once for each year of available data for the Bear River and 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.

Q. Does using the VISTA model cause an increase in net power costs?

A. No. Net power costs are lower as a result of adopting the VISTA model. However, the new licensing requirements for the Umpqua River projects – which were partially effective September 2003 with the remainder effective January 1, 2006 – updated Klamath River restrictions, and the new Grant County contract (which is effective November 2005) offset the NPC decrease**.**

The above decreases in hydro availability are offset by the return of Swift Unit 2 and upgrades at J.C. Boyle.

Q. Please describe the changes in the new Umpqua license, updated Klamath River restrictions, and the new Grant County contract that increase NPC.

A. For the Umpqua River, effective 2001, the Soda plant is operated more like a re-regulation facility than in the past – by smoothing out the flow and following a 5 percent change per 24-hour rule. In September 2003, the minimum fish flow below Soda was increased from 25 to 95 cubic feet per second. Additional minimum flow requirements phase in over time. By January 1, 2006, all of the minimum by pass flows will be in operation. By 2006, the estimated impact of these changes is a generation loss of 125,000 MWh per year.

The Klamath River VISTA generation included in the Company's previous filing did not reflect the Bureau of Reclamation's operating strategies. Those strategies are impacted by endangered species act requirements, fishery obligations, and tribal trust responsibilities. In addition, other environmental considerations in the upper Klamath Basin and on the Klamath River below Iron Gate dam have increased the pressures on water supply. To help ensure full delivery of water to Klamath Irrigation Project farmers, the US Bureau of Reclamation has routinely directed the amount of flow through the Company's hydro facilities. These actions have reduced the Company's hydro operating flexibility and operating effectiveness. These operating constraints are included in VISTA simulations to reflect the US Bureau of Reclamation's water management policies and flow directives.

The Priest Rapids Project consists of the Priest Rapids Development and the Wanapum Development. Two contracts with Grant are tied to the Priest Rapids Project. Each of the contracts allocates to the Company a percentage of the firm energy and capacity of the Development, plus the same percentage of non-firm energy from the development. The contract for the Priest Rapids Development (13.9 percent) expires October 31 2005. The contract for the Wanapum Development (18.7 percent) expires October 31 2009. The two contracts are succeeded by a set of contracts related to the Priest Rapids Project. They are:

- Priest Rapids Product Sale Contract

- Priest Rapids Reasonable Portion Power Sales Contract
- Additional Products Sales Agreement

The Product Sale contract allocates the Company a percentage of the project that is surplus to Grant's needs (Surplus Product). The percentage includes firm energy and capacity of the project, plus the same percentage of non-firm energy from the project. This contract also allocates the Company a percentage of the energy that becomes available when Grant buys displacement energy from BPA (Displacement Product). The Additional Products Sales Agreement gives the Company a percentage of Grant's non-firm energy from the project. In the pro forma period the Company estimates the new contracts will result in a reduction of approximately 95,000 MWh in energy compared to the prior contract. The Reasonable Portion Power Sales contract gives the Company a percentage of the net proceeds from selling the Reasonable Portion of the contract. The Reasonable Portion is the 30 percent of the Project, also subject to Grant's load requirements, that must be sold in the market place.

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;
- Reserve requirement, both spinning and ready;
- 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. 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 operating relationship in the environment that it operates in?

A. Yes. The GRID model appropriately simulates the operation of the Company's system over a variety of streamflow conditions consistent with the Company's operation of the system including 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 system 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 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 future peak generation capability for the Company's winter and summer peak loads and the Company's energy load for the pro forma period.

PCAM

Q. Why is the Company requesting a PCAM in this proceeding?

A. Ms. Omohundro's testimony explains many of the reasons for the Company's request. In addition, the Company's net power cost exposure to losses is asymmetric. Costs can only decline to zero while cost increases are, theoretically, unlimited. While it is unlikely that costs will fall to zero or increase infinitely, the limitations are relevant. For example, as explained below, since 1999 the largest decrease in net power cost below authorized levels was dwarfed by the largest increase above authorized levels. This causes the Company to bear a disproportionate share of net power costs incurred to serve retail customers. As a consequence, the Company's opportunity to earn its authorized rate of return over the long run will be greatly diminished if not eliminated, because NPC is such a large component of revenue requirement.

Q. Please define net power cost exposure.

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

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

A. Exhibit No.___(MTW-4) shows the historical net power cost exposure experienced from 1990 through 2004. From 1990-2000, the information is based on Oregon data because the Company did not have Washington general rate cases during that period. As shown, the net power cost exposure varied between an $83 million gain and a $724 million loss total Company. In aggregate, losses exceeded gains by $1.6 billion.

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

A. No. Beginning in 2000, with the start of the Western energy crisis, the exposure has become very asymmetric. From 1990 through 1999, the Company's net power cost exposure averaged negative $10.7 million or 2.62 percent of authorized net power costs and from 2000-2004 it averaged $335.5 million in excess costs or 68.12 percent of authorized net power costs. In percentage terms, the exposure increased by over 3100 percent since 1999.

Q. Are the factors which significantly increased the asymmetry controllable by the Company?

A. No. Deviations from NPC in rates are primarily related to factors not controllable by the Company. For example, hydro conditions, weather conditions, wholesale market prices for natural gas and electricity and the timing of forced outages are not controllable. While these potential causes have always been present, the cost of addressing these factors has increased dramatically. The overwhelming cause of the cost increase is due to an increase in wholesale market prices and price volatility. For example, assume actual hydro generation for fiscal 2004 was 1.5 million MWh below normal. At market prices prevalent from 1990 through 1999, replacement power would have cost $25 million on average. At 2004 average market prices, replacement power would have cost approximately $67 million. Historical market prices are shown in Exhibit No.___(MTW-5). Unless changes are made to the Company's Washington regulatory structure, this asymmetry will continue to increase as wholesale market prices and price volatility increase.

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

A. While there will be year-to-year volatility of wholesale market prices, the expected trend is up. Exhibit No.___(MTW-6) is the Company's Official Price Projection of future market prices.

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

A. Yes. As described in Ms. Omohundro's testimony, both PSE and Avista have PCAMs in place. Further, as discussed in the Standard and Poor's article included in Ms. Omohundro's testimony as Exhibit No.___(CAO-2), most of the investor owned electric utilities located in the WECC currently have some form of power cost recovery mechanism, with the exception of a few utilities including the Company and Portland General Electric (PGE). An important factor that should be considered in the Commission's evaluation of our request is the fact that the Company has more exposure than many of the other utilities located throughout the WECC because of the variability of hydro resources in our portfolio.

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 adjusted actual net power costs from the authorized baseline net power costs with one exception. The one exception is that 100 percent of cost increases or decreases related to Qualifying Facility contracts should be recovered from customers since the purchases are required by PURPA. All other costs would be subject to a symmetrical sharing mechanism that allocates 90 percent of cost increases and decreases to customers and 10% to shareholders. Mr. Duvall describes the steps necessary to allocate the deferrals to Washington pursuant to Revised Protocol.

Q. Does the proposed PCAM include any other adjustments in addition to the net power cost impacts?

A. Yes. The Company proposes that the retail revenue impact of changes in Washington retail loads from the level included in rates be accrued monthly to the PCAM account. The accrual would be calculated by multiplying the portion of the retail rate related to the production revenue requirement by the change in retail load. Under this approach, increased retail revenue related to load increases would be netted against increased net power costs and, conversely, revenue decreases related to declines in loads would be netted against decreased net power costs accrued to the PCAM account. The Company intends this provision to be equivalent to the "retail revenue adjustment" feature of Avista Corporation's Energy Recovery Mechanism (ERM).

Q. Please explain why the Company is proposing a higher sharing percentage in Washington (90%) than the Company is proposing in Oregon (70%).

A. The Oregon proposal includes a feature whereby the Company will be able to update its net power costs annually. Specifically, the Company has requested a Transition Adjustment Mechanism in Oregon to implement direct access consistent with the RVM mechanism approved for Portland General Electric. As part of the Transition Adjustment Mechanism (TAM), the Company would be able to update net power costs annually on a forecast basis and thereby significantly reduce regulatory lag. Because of the lag reduction, the Company requested sharing bands of 70 percent customers and 30 percent shareholders. Since a mechanism similar to the TAM does not exist in Washington, we are requesting the higher allocation to customers. Nonetheless, the Company will still have substantial incentives to keep costs as low as possible as a result of lag and the sharing band.

Q. Please define the "baseline" net power costs.

A. The baseline will be the authorized net power costs in effect during the measurement period. The measurement period should be tied to the balancing account trigger, which is discussed below. The baseline will be in effect until the Company's rates are adjusted through a general rate case.

Q. Please define "adjusted actual" net power costs.

A. Adjusted actual net power costs are equal to actual net power costs adjusted to remove prior period adjustments recorded during the accrual period and to include Commission-adopted adjustments from the most recent rate case. For example, actual results would be adjusted to reflect the Commission-adopted SMUD wholesale sale revenue imputation adjustment. On the other hand, hydro normalization and forced outage rate adjustments would be excluded**.**

Q. How are the calculated variances accrued and collected from or returned to customers?

A. The Washington net power cost variances would be determined on a monthly basis and posted to a Balancing Account. An entry into this Balancing Account will occur in every month unless the actual adjusted net power cost is identical to the level in rates. A positive balance represents money owed to the Company by its customers. A negative balance indicates money the Company owes to customers. The balance will accrue interest at the Company's authorized rate of return.

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

A. No. Rather than establishing a fixed schedule for such filings, the Company proposes that a plus or minus $5 million accrued balance on a Washington-allocated basis be established as a trigger. Once the trigger is reached, the Company will be required to return the balance to, or request recovery from, customers. This approach is more beneficial than setting a fixed schedule because it should reduce the number of rate changes during periods of lower net power cost volatility, reduce rate shock during periods of higher volatility when balances could be much higher, and provide more current price signals during periods of higher volatility. The Company proposes a one-year amortization period.

Q. Is the mechanism designed to take into account all NPC components?

A. Yes. The mechanism is designed to include the impact of cost changes for fuel, wheeling and purchase power expenses and wholesale electricity and gas sales, because all net power cost components can be affected by volatility. For example, high electric wholesale market prices relative to natural gas wholesale market prices can lead to the redispatch of the Company's gas thermal units in order to make wholesale sales and/or avoid higher-priced market purchases and higher fuel costs. If the mechanism covered only purchases and fuel expense, it would not provide a proper matching of costs and benefits.

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

A. Exhibit No.___(MTW-7) is an illustration of how the Company's proposed PCAM would have operated during calendar year 2004 assuming the net power costs authorized in Docket No. UE-032065 had been in effect for the entire year. As shown, the Total Company NPC variance from Washington authorized net power costs was $211.5 million. After exclusion of the Company's $21.5 million share, $27.8 was related to Company-owned West hydro, $8.9 million was related to Company owned East hydro, $3.1 million was related to Mid-Columbia hydro, $6.7 million was related to existing QF contracts, and $144.5 million was related to All Other, which includes fuel prices, market prices contract changes, etc. Washington's 90% allocated share of these costs would have been $18.1 million. The revenue impact of the load changes was $5.1 million, leaving a net Washington impact of $13.1 million.

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

A. Yes. However, costs and revenues related to existing contracts and resources that have previously been included in rates should be exempt from a prudence review on a cost basis. Of course, the manner in which generation facilities were operated and contracts dispatched during the accrual period would be subject to review along with other new contracts.

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.

Q. Could the specifics of this PCAM proposal be affected by the design of a decoupling proposal?

A. Yes. The direct testimony of Don Furman discusses the relation between the PCAM and decoupling.

Q. Please explain the Company's earnings demonstration proposal.

A. If the Company's actual rate of return during the deferral period is above authorized levels, costs deferred during that period would not be recoverable. Conversely, if earned rates of return are below authorized levels, deferred balances owed to customers would not be returned.

Q. Does this conclude your direct testimony?

A. Yes.