BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA UTAH POWER & LIGHT COMPANY FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES	) CASE NO. PAC-E-05-1)) Direct Testimony of Mark T. Widmer)

PACIFICORP

CASE NO. PAC-E-05-1

January 2005

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

A. My name is Mark T. Widmer, my business address is 825 N.E. Multnomah, Suite 800, Portland, Oregon 97232, and my present position 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 results of the production cost model study for the twelve-month test period ended March 31, 2004 with known and measurable changes as discussed in my testimony. I describe the Company's production cost model, the Generation and Regulation Initiatives Decision Tools (GRID) model, which is used to calculate net power costs. I provide information on how input data is normalized in GRID and the rationale for doing so. I describe hydro modeling associated with the VISTA hydro model. Finally, I describe the Aquila Hydro hedge and the Company's proposed method of including the associated costs and benefits in rates.

Net Power Cost Results

Q. What are the net power cost results?

A. Normalized net power costs are approximately $644.5 million. In comparison, actual results for the twelve-month period ending September 2004 are approximately $726 million.

Q. How does this compare with the level presented to the Commission in the Company's last semi-annual filing?

A. Proposed net power costs are approximately $2.5 million higher than the $642 million included in the Company's last semi-annual report for FY 2004. The difference is related to information updates that have become available since the semi-annual was filed.

Q. How is the Company handling the Currant Creek plant?

A. The Company has contracted for the construction of the Currant Creek plant and expects the plant to be available in its simple cycle combustion turbine configuration in July 2005. For purposes of this filing, the Company has assumed that the plant is available and provides benefits to rate payers during the entire test period because it will be in service when rates go into effect.

Determination of Net Power Cost

Q. Please explain net power costs.

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

Q. Are the proposed net power costs which you are sponsoring developed with the same production dispatch model used in the preparation of the semi-annual reports that are filed with the Commission?

A. Yes.

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

A. Net power costs were calculated for an historical test period based on normalized data using the GRID model. For each hour in the period the model simulates the operation of the power supply portion of the Company 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. Please explain how GRID calculates future net power costs.

A. The development of expected net power costs begins with the selection of a test period. This filing is an historical normalized test period. I have divided the description of the power cost model into three sections, which follow 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 the Company uses to calculate net power costs. It is a server-based application that uses the following high-level technical architecture to calculate net power costs:

- An Oracle-based data repository for storage of all inputs,
- A Java-based software engine for algorithm and optimization processing,
- Outputs that are 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. 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 the calculations in more detail.

Generation 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 month in order to maximize usage during peak load hours. The monthly shape of a non-run of river project is based on the hourly retail load and market prices in a month, and incorporates minimum and maximum flow for the project to account for environmental constraints. The dispatch of the generation is flat in all hours of the month for run of river projects. The hourly dispatched hydro generation is used in the Dispatch 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: These contracts are place holders for capturing fixed cost. 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 whose term is 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 North American Electric Reliability Council (NERC) requires all companies with generation to carry operating 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. 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 the Western Electricity Coordinating Council (WECC) require companies with generation to carry spinning reserves to protect the WECC system from cascading loss of generation or transmission lines, uncontrolled separation and interruption of customer service.

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

A. The model calculates operating reserve requirements (both spinning and ready) for the Company's East and West control areas, plus regulating margin that is added to spinning reserve requirement. The total operating 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 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, the Gadsby CT units and the 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. 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.

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.

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 historical normalized hourly firm retail load that the Company served within all of its jurisdictions for the twelve-month period ending March 31, 2004 (FY 2004). These loads are 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 four years of historical outage rates and maintenance for each unit. 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 48-month period ending March 2004 is used in this filing. Other thermal plant data include unit capacity, minimum generation level, minimum up/down time, fuel cost, and startup cost. The four-year average approach has been used for over 10 years.

Q. Are there any exceptions to the four-year averge 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. As stated earlier, the Company has a new source for its hydro data. The Company is using 19 sets of expected generation from the VISTA hydro model rather than using the 50 years of adjusted actual stream flows.

Q. In previous GRID studies, 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 are 60 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.

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, 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 of quantity and price. The contract may specify an exact quantity of capacity and energy or a range bounded by a maximum and minimum amount, or it may be based on the actual operation of a specific facility. Prices may 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 long-term contracts 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. The data for firm wheeling is based on contracts to which the Company is a party. The firm transmission rights modeled in GRID are developed from the Company's OASIS for summer/winter postings. The limited additional transmission rights that the Company may have access to are based on the experience of the Company's Commercial and Trading Department.

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

A. The GRID model uses four wholesale markets to balance and optimize the system. The four markets are at Mid Columbia, COB, SP15 and Palo Verde (Desert Southwest), where the model makes both system balancing sales and purchases if it is economical to do so under constraints. The input data regarding wholesale markets include market 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 Mid Columbia, COB, SP15 and Palo Verde (DSW) are the Company's monthly forward price curves for the period April 2004 through March 2005 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 used in this case.

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

1. Owned and purchased hydroelectric generation is normalized by running the production cost model for each of the 19 different sets of hydro generation. The resultant 19 sets of thermal generation, system balancing sales and purchases, and hydroelectric generation are then averaged. As previously explained, normalized thermal availability is based on a four-year average.
2. Wholesale market prices are adjusted to reflect expected prices during the normalized period.
3. Long-term firm wholesale sales and purchase contracts are redispatched based on the normalized wholesale market prices and known changes in the contracts.
4. Wheeling expense is adjusted for known contractual changes.
5. System load net of special sales is adjusted to reflect loads that would have occurred under normal temperature conditions.

Q. You stated that hydroelectric generation is normalized by using historical water data. Please explain why the regulatory Commissions and the utilities of the Pacific Northwest have adopted the use of production cost studies that employ historical water conditions for 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, therefore, have adopted production cost analysis that simulates the operation of the entire system using historical water conditions, as being representative of what can reasonably be expected to occur.

VISTA Model

Q. Is the Company switching to the VISTA Model for hydro generation normalization as a result of concerns raised by regulators?

A. Yes. During the Oregon UE-147 settlement discussions, Oregon staff expressed concern over the vintage of the 50-year hydro data. In addressing the hydro issue, the Company agreed to prepare a proposed methodology that captures the current hydro capability.

Q. Are there additional reasons for the Company to change to the VISTA model?

A. Yes. As far back as the mid-1970's, PacifiCorp and other utilities in the Northwest have used regional historical stream flow records provided by the Bonneville Power Administration (BPA) to normalize expected hydro generation. BPA adjusted the historical stream flow 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-1980's BPA added a block of ten years to the adjusted numbers.

In the 1990's, when BPA was mandated 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 used in prior general rate cases are growing 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 has been using 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). Starting in spring 2004, the Company is using the VISTA model to develop hydro generation for its short term planning.

Based on the need for more current hydro information, the Company's experience with the VISTA model, and the Oregon UE-147 stipulation, the Company is proposing to use the VISTA model in general rate cases.

Q. Please describe 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 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 physical project data, constraint description, and historical stream flows 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 and in the Company's Integrated Resource Planning process.

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. Please describe the VISTA model inputs.

A. The VISTA input data come from a variety of sources characterized into 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 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 60 years of "modified" stream-flow 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 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. The weekly data is aggregated to the monthly level for use in GRID.

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 now 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. These probabilities can also be thought of as percentiles. The Company is using 19 sets of expected generation from the VISTA model rather than using the 50 water years of adjusted actual previously employed. The 19 sets of generation consist of the 5th percentile through the 95th percentile in increments of 5 percent. The wettest year is the 5th percentile and the 95th percentile is the driest. The normalized net power costs are the average of the 19 net power cost studies using the 19 "exceedence level" sets of hydro generation.

Q. Does using the VISTA model cause an increase in NPC?

A. No. Net power costs are lower as a result of adopting the VISTA model.

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 for more detailed analyses are also available, and the format can be specified as hourly, daily, monthly, annually and by heavy load hours and light load hours.

Q. Do you believe that the GRID model appropriately reflects the operation of the Company's system?

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

Q. Please describe Exhibit No. 10.

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 test period. The total shown on line 11 represents the total usage of resources during the test period to serve system load. Line 12 consists of wholesales sales made to neighboring utilities within the Pacific Northwest, the Pacific Southwest, and the Desert Southwest as calculated from the production cost model study. Line 13 represents the Company's System Load net of special sales.

Q. Please describe Exhibit No. 11.

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 test period.

Aquila Hydro Hedges

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

A. To mitigate the negative effects of annual fluctuations of hydro conditions upon net power costs, the Company has entered into a contract (the "Aquila Hydro Hedge") with Aquila Risk Management Corporation ("Aquila") that provides some financial protection when stream flow levels are low. The cost of the Aquila Hydro Hedge, $1.75 million on a total Company basis, is included in net power costs. The financial contract is structured as a collar, whereby PacifiCorp makes a payment to Aquila if stream flows are above a certain level (when power prices would tend to be low), and Aquila makes a payment to PacifiCorp if stream flows are below a certain level (when power prices would tend to be high). The Aquila Hydro Hedge is measured on a quarterly and October to September contract year basis. Any payments will be made on a quarterly basis based on actual stream flows for that quarter. Any payments made or received are held on the Company's balance sheet until a final determination for the contract year. The Company proposes these revenues and costs should be passed to customers through a balancing account.

Q. Should this treatment also apply to the Constellation Temperature Hedge?

A. Yes.

Q. Does this conclude your direct testimony?

A. Yes.