Exhibit No.___(HS-2)
Docket No. UE-09___
Witness: Hui Shu

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PACIFICORP dba Pacific Power Respondent.	)))))))))))	Docket No. UE-09______

PACIFICORP

EXHIBIT OF HUI SHU

GRID and Vista Model Descriptions

February 2009

GRID Model for Net Power Cost Calculations

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 Generation and Regulation Initiatives Decision Tools (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

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, wind generation, 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 in 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 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 west control area.

Generating Resources in Pre-Dispatch

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

A. The Pre-dispatch logic reads the inputs 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 west control area 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 constraints for the project to account for hydro license constraints. The dispatch of the generation from run-of-river projects is flat in all hours of the week. 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 system in the 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. Companies must carry contingency reserves to meet the most severe single contingency (MSSC) or five percent for operating hydro and wind resources and seven 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 five percent of dispatched hydro and wind, plus seven 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. 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 applied 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.

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. Inputs used in GRID include retail loads, thermal plant data, hydroelectric generation data, wind plant 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 normalized hourly firm retail load that the Company expects to serve within its west control area for the 12-month test period. 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. 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. When a plant has not been in service for the entire four-year period, 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 uses the output from the VISTA hydro regulation model for GRID's hydroelectric generation input data. The Company uses 40-water years' of expected generation from VISTA. The VISTA model is described in more detail later in this attachment.

Q. Does the Company use other hydro generation inputs?

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

Q. **Please describe the wind generation input data.**

A. The Company uses wind site information from the project developers or based on historical generation, if available, to estimate the projected wind generation.

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 or a market index (such as California Oregon Border ("COB"), or Mid-Columbia ("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 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 wheeling expense for the 12-month historic period that is available at the time of the test period study, adjusted for known contract changes through the 12-month test period. Firm transmission rights between transmission areas in the GRID topology are based on the Company's Merchant Function contracts with the Company'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 system. The two wholesale markets in the west control area are at Mid-C and COB. Subject to the constraints of the west control area 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 the two liquid markets are from the Company's most recent Official Forward Price Curve that is available at the time of the study, shaped into hourly prices. The market price hourly scalars are developed by the Company's commercial and trading department based on historical hourly data. 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 proforma test years.

A. For proforma test years, normalization of input data for the production costs model is primarily limited to hydro data:

- Owned and purchased hydroelectric generation is normalized by running the production cost model for each of the 40 hydro generation levels. The resultant 40 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.

Q. 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 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 the need for thermal 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 under normal conditions.

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;
- Dispatch of wind 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 west control area including operating constraints and requirements.

VISTA Model for Hydro Optimization

Q. What is the VISTA model?

A. The Company uses the VISTA Decision Support System (DSS) developed by Hatch Ltd (previously Synexus Global) 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. The market prices used in the VISTA model are the same prices used to produce the net power costs.

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

A. No. 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 Integrated Resource Plan (IRP) process, except that the Company is required by the Commission to use 40-water year history for rate setting purposes.

Q. Do other utilities use the VISTA DSS model?

A. The VISTA DSS model is used by a growing number of other energy companies all over the world including the Bonneville Power Administration (BPA).

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. The Mid-Columbia projects use 70 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. 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 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 operational changes at the particular plant that are the result of new license constraints.

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, Klamath and Umpqua Rivers, the historical stream flows used as inputs to the VISTA model are the flows that have been calculated and recorded by the Company at each of the projects. Generally, flows are developed using a simple continuity of water equation where Inflow = Outflow + Change in Storage.

For the Umpqua River in particular, the stream flow data was constructed by piecing together a variety of historical data sources. The U.S. Geological Survey gauge data at Copeland at the outflow of the entire project provides the only long term recorded flows for the Umpqua basin. Moving upstream data was developed by comparison to similar watersheds and comparison to data published by the Northwest River Forecast Center combined with the continuity of water equation, described above, to determine where in the basin flows originated. In the last three to five years the Company has installed a number of gauging stations, which will help improve the data quality.

The Company's Mid-Columbia energy is determined by using VISTA to optimize the operations of the six hydro electric facilities below the Chief Joseph dam. Estimates of Mid-Columbia generation are complicated by the fact that this section of the river is subject to river flows regulated by the many large projects that are located upstream. The Company's Mid-Columbia generation is based on the regulated stream resulting from 70 years of “modified” stream flow conditions as modeled by the Pacific Northwest Power Pool.

The modified stream flows are the flows developed by the Bonneville Power Administration by determining the natural stream flow for the period of record and then modifying the historical data to reflect the year-2000 level of irrigation and development in the Columbia basin. [*2000 Level Modified Stream flow, 1928-1999*; Bonneville Power Administration. May 2004.] These modified flows are used by Pacific Northwest Power Pool to model the operation (regulation) of the entire Columbia Basin as it exists today. There are many variations of the Columbia River operations model results. We are using the “PNCA Headwater Payments Regulation 2004-05” file, also known as “The 2005 70 year Reg” file, completed in July 2005 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 streamflow data are the most current information available to the Company and serve as an input to the VISTA model.

The modeled discharge of the Grand Coulee Reservoir becomes the source of inflow data to the Company's model of the Mid-Columbia River generation.