

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

3 A. My name is Mark T. Widmer, my business address is 825 N.E. Multnomah, Suite
4 600, Portland, Oregon 97232, and my present title is Director, Net Power Costs.

5 **Qualifications**

6 **Q. Briefly describe your education and business experience.**

7 A. I received an undergraduate degree in Business Administration from Oregon State
8 University. I have worked for PacifiCorp since 1980 and have held various
9 positions in the power supply and regulatory areas. I was promoted to my present
10 position in September 2004.

11 **Q. Please describe your current duties.**

12 A. I am responsible for the coordination and preparation of net power cost and
13 related analyses used in retail price filings. In addition, I represent the company
14 on power resource and other various issues with intervenor and regulatory groups
15 associated with the regulatory commissions in the six states in which the
16 Company operates.

17 **Summary of Testimony**

18 **Q. Will you please summarize your testimony?**

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

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

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

10 **Net Power Cost Results**

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

12 A. The proposed net power costs are approximately \$417 million for the Company's

13 west control area.

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

15 **basis?**

16 A. In Docket No. UE-032065 – the last proceeding in which net power costs were

17 determined in a Commission order – the Commission authorized the Company to

18 recover net power costs of approximately \$43.5 million in rates. In this

19 proceeding, the Washington share of the company's west control area proposed

20 net power costs is approximately \$95.5 million. Those cost increases are due to a

21 variety of factors which include the West Control Area (WCA) allocation

22 methodology, the expiration of long-term firm wholesale sales and purchase

23 power contracts, fuel cost increases for the Hermiston, Jim Bridger and Colstrip 4

1 thermal generating facilities, increased third-party wheeling costs and decreased
2 hydro generation at Company-owned facilities and at Mid-Columbia resources
3 from which the Company purchases power.

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

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

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

23 A. Yes. The fuel price for the Jim Bridger plant has increased by approximately 33

1 percent. The wholesale market price of electricity at California Oregon Border
2 (COB) and Mid-Columbia (Mid-C) has increased approximately 16 percent and
3 14 percent, respectively. The fuel price for Hermiston has increased
4 approximately 15 percent. Washington retail loads have increased by
5 approximately 205,000 MWh. Further, wholesale contracts such as the now-
6 expired Puget Sound Energy wholesale sales contract, which were an offset to net
7 power costs, have expired.

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

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

13 **Determination of Net Power Costs**

14 **Q. Please explain net power costs.**

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

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

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

1 New analysis features of note are:

- 2 • Provides an MMBtu report
- 3 • Provides finer granularity in LTC cost reporting

4 New graphic user interface features of note are:

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

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

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

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

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

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

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

20 A. GRID isolates west control area loads and resources from east control area loads
21 and resources. West control area loads consist of:

- 22 • Retail loads for the Company's Washington, Oregon and California retail
23 jurisdictions, and

- 1 • Long-term and short-term firm wholesale sales whose point of delivery is
2 in the west control area unless the transaction is tied to a specific east side
3 resource such as Foote Creek.

4 West resources consist of:

- 5 • Jim Bridger and Colstrip 4 coal generation facilities,
6 • Hermiston combined cycle combustion turbine generation facility,
7 • Owned and contracted hydro generation facilities, and
8 • Long-term and short-term firm purchase power contracts excluding
9 Oregon and California Qualifying Facility contracts.

10 GRID optimization functions over the west control area transmission topology
11 which consists of third party contractual rights and rights that Merchant has
12 acquired from PacifiCorp transmission. East-west control area exchanges and
13 transfers between the west and the east are excluded.

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

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

19 **Q. Please explain how the company calculated pro forma normalized net power**
20 **costs.**

21 A. Net power costs are calculated using the GRID model. For each hour in the pro
22 forma period, the model simulates the operation of the power supply portion of
23 the Company's west control area under a variety of stream flow conditions. The

1 results obtained from the various stream flow conditions are averaged and the
2 appropriate cost data is applied to determine an expected net power cost under
3 normal stream flow and weather conditions for the test period.

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

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

20 **Q. Please explain how GRID projects net power costs.**

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

23 • The model used to calculate net power costs.

- 1 • The model inputs.
- 2 • The model output.

3 **The GRID Model**

4 **Q. Please describe the GRID model.**

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

- 8 • An Oracle-based data repository for storage of all inputs,
- 9 • A Java-based software engine for algorithm and optimization
10 processing,
- 11 • Outputs that are exported in Excel readable format, and
- 12 • A web browser-based user interface.

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

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

17 A. West control area net power costs are calculated hourly using the GRID model.

18 The general steps are as follows:

- 19 1. Determine the input information for the calculation, including retail load,
20 wholesale contracts, market prices, thermal and hydro generation capability,
21 fuel costs, transmission capability and expenses.
- 22 2. The model calculates the following pre-dispatch information:
 - 23 • Thermal availability

- 1 • Thermal commitment
- 2 • Hydro shaping and dispatch
- 3 • Energy take of long term firm contracts
- 4 • Energy take of short term firm contracts
- 5 • Reserve requirement and allocation between hydro and thermal
- 6 resources

7 3. The model determines the following information in the Dispatch
 8 (optimization) logic, based on resources, including contracts, from the pre-
 9 dispatch logic:

- 10 • Optimal thermal generation levels, and fuel expenses
- 11 • Expenses (revenues) from firm purchase (sales) contracts
- 12 • System balancing market purchases and sales necessary to balance and
- 13 optimize the west control area and net power costs taking into account
- 14 the constraints of the west control area
- 15 • Expenses for purchasing additional transmission capability

16 4. Model outputs are used to calculate net power costs on a total west control
 17 area basis, incorporating expenses (revenues) of purchase (sales) contracts that
 18 are independent of dispatched contracts, which are determined in step 3.

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

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

22 A. The Dispatch logic is a linear program (LP) optimization module, which
 23 determines how the available thermal resources should be dispatched given load

1 requirements, transmission constraints and market conditions, and whether market
2 purchases (sales) should be made to balance the west control area. In addition, if
3 market conditions allow, market purchases may be used to displace more
4 expensive thermal generation. At the same time, market sales may be made either
5 from excess resources or market purchases if it is economical to do so under
6 market and transmission constraints.

7 **Q. Does the Pre-dispatch logic provide thermal availability and system energy**
8 **requirements for the Dispatch logic?**

9 A. Yes. Pre-dispatch, which occurs before the Dispatch logic, calculates the
10 availability of thermal generation, dispatches hydro generation, schedules firm
11 wholesale contracts, and determines the reserve requirement of the Company's
12 west control area. In my following testimony, I'll describe each of these
13 calculations in more detail.

14 **Generating Resources in Pre-Dispatch**

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

17 A. The Pre-dispatch logic reads the input regarding thermal generation by unit, such
18 as nameplate capacity, normalized outage and maintenance schedules, and
19 calculates the available capacity of each unit for each hour. The model then
20 determines the hourly commitment status of thermal units based on planned
21 outage schedules, and a comparison of operating cost vs. market price if the unit
22 is capable of cycling up or down in a short period of time. The commitment
23 status of a unit indicates whether it is economical to bring that unit on line in that

1 particular hour. The availability of thermal units and their commitment status are
2 used in the Dispatch logic to determine how much may be generated each hour by
3 each unit.

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

5 A. In the Pre-dispatch logic, the Company's available hydro generation from each
6 non-run of river project is shaped and dispatched by hour within each week in
7 order to maximize usage during peak load hours. The weekly shape of a non-run
8 of river project is based on the net system load. The dispatch logic incorporates
9 minimum and maximum flow for the project to account for hydro license
10 constraints. The dispatch of the generation is flat in all hours of the month for run
11 of river projects. The hourly dispatched hydro generation is used in the Dispatch
12 logic to determine energy requirements for thermal generation and system
13 balancing transactions.

14 **Wholesale Contracts in Pre-Dispatch**

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

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

23 • Energy Limited (shape to price or load): The energy take of these

1 contracts have minimum and maximum load factors. The complexities
2 can include shaping (hourly, annual), exchange agreements, and call/put
3 optionality.

4 • Generator Flat (or Fixed Pattern): The energy take of these contracts is
5 tied to specific generators and is usually the same in all hours, which takes
6 into consideration plant down time. There is no optionality in these
7 contracts.

8 • Fixed Pattern: These contracts have a fixed energy take in all hours of a
9 period.

10 • Complex: The energy take of one component of a complex contract is tied
11 to the energy take of another component in the contract or the load and
12 resource balances of the contract counter party.

13 • Contracted Reserves: These contracts do not take energy. The available
14 capacity is used in the operating reserve calculation.

15 • Financial: These contracts are place holders for capturing fixed cost or
16 revenue. They do not take energy.

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

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

21 A. Yes. Whether a wholesale contract is identified as long-term firm is entirely based
22 on the length of its term. Consistent with previous treatment, the Company
23 identifies contracts with terms greater than one year by name. Short-term firm

1 contracts are grouped by delivery point. If a short-term firm contract has
2 flexibility as described for long-term firm contracts, it will be dispatched using the
3 appropriate archetype and listed individually with the long-term contracts. Hourly
4 contract energy dispatch is used in the Dispatch logic to determine the
5 requirements for thermal generation and system balancing transactions.

6 **Reserve Requirement in Pre-Dispatch**

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

9 A. The Western Electricity Coordinating Council (WECC) and the North American
10 Electric Reliability Council (NERC) set the standards for reserves. All companies
11 with generation are required to maintain Operating Reserves, which comprise two
12 components – Regulating Reserve and Contingency Reserve. The Company must
13 carry contingency reserves to meet its most severe single contingency (MSSC) or
14 5 percent for operating hydro and wind resources and 7 percent for operating
15 thermal resources, whichever is greater. A minimum of one-half of these reserves
16 must be spinning. Units that hold spinning reserves are units that are under
17 control of the control area. The remainder (ready reserves) must be available
18 within a 10-minute period. NERC and WECC require companies with generation
19 to carry spinning reserves to protect the WECC system from cascading loss of
20 generation or transmission lines, uncontrolled separation and interruption of
21 customer service.

22 Regulating Reserve is an amount of Spinning Reserve immediately
23 responsive to automatic generation control (AGC) to provide sufficient regulating

1 margin to allow the control area to meet NERC's Control Performance Criteria.

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

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

12 **Q. How does the model satisfy reserve requirements?**

13 A. Reserves are met first with unused hydro capability, then by backing down thermal
14 units on a descending variable cost basis. Spinning reserve is satisfied before the
15 ready reserve requirement. For the west control area, spinning reserve requirement
16 is fulfilled using hydro resources and thermal units that are equipped with
17 governor control. The ready reserve requirement is met using purchase contracts
18 for operating reserves, the remaining unused hydro capability, and by backing
19 down thermal units. The allocated hourly operating reserve requirement to the
20 generating units is used in the Dispatch logic to determine the energy available
21 from the resources and the level of the system balancing market transactions.

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

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

8 **GRID Model Inputs**

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

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

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

15 A. The retail load represents the forecasted hourly firm retail load that the Company
16 serves within all of its west control area jurisdictions for the twelve-month test
17 period ending March 31, 2006. This load is modeled based on the location of the
18 load and transmission constraints between generation resources to load centers.

19 **Q. Please describe the thermal plant inputs.**

20 A. The amount of energy available from each thermal unit and the unit cost of the
21 energy are needed to calculate net power costs. To determine the amount of
22 energy available, the Company averages for each unit four years of historical
23 outage rates and maintenance. The heat rate for each unit is determined by using

1 a four-year average of historical burn rate data. By using four-year averages to
2 calculate outages, maintenance and heat rate data, annual fluctuations in unit
3 operation and performance are smoothed. The four-year average approach has
4 been used in rate case filings for over 10 years. For this particular filing, the 48-
5 month period ending March 2006 is used. Other thermal plant data includes unit
6 capacity, minimum generation level, minimum up/down time, fuel cost, and
7 startup cost.

8 **Q. Please describe the hydroelectric generation input data.**

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

- 11 • Owned west side hydro water years 1964-2003;
- 12 • Mid-Columbia contracts water years 1964-1988 with 1989 -2003 mapped
13 as described below; and
- 14 • Small hydro using available data – starting in 1982 to 2003 with 1964 -
15 1982 mapped as described below.

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

1 **Q. Does the Company use other hydro generation inputs?**

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

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

6 A. The data for firm wholesale sales and purchases are based on west control area
7 contracts to which the Company is a party. Each contract specifies the basis for
8 quantity and price. The contract may specify an exact quantity of capacity and
9 energy or a range bounded by a maximum and minimum amount, or it may be
10 based on the actual operation of a specific facility. Prices may also be specifically
11 stated, may refer to a rate schedule, a market index such as COB or Mid-C, or
12 may be based on some type of formula. The long-term firm contracts are
13 modeled individually, and the short-term firm contracts are grouped based on
14 general delivery points. The contracts with flexibility are dispatched against the
15 hourly market prices so that they are optimized from the point of view of the
16 holder of the call/put.

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

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

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

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

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

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

10 A. The market prices for the system balancing wholesale sales and purchases at two
11 liquid markets are from the Company's official monthly forward price forecast as
12 of August 31, 2006 shaped into hourly prices. The market price hourly scalars are
13 developed by the Company's Commercial and Trading Department based on
14 historical hourly data since April 1996. Separate scalars are developed for on-
15 peak and off-peak periods and for different market hubs to correspond to the
16 categories of the monthly forward prices. Before the determination of the scalar,
17 the historical hourly data are adjusted to synchronize the weekdays, weekends and
18 holidays, and to remove extreme high and low historical prices. As such, the
19 scalars represent the expected relative hourly price to the average price forecast
20 for a month. The hourly prices for the test period are then calculated as the
21 product of the scalar for the hour and the corresponding monthly price.

1 **Normalization**

2 **Q. Please explain what is meant by normalization and how it applies to the**
3 **production cost model for historic test years.**

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

12 **Q. You stated that hydroelectric generation is normalized by using historical**
13 **water data. Please explain why the regulatory commissions and the utilities**
14 **of the Pacific Northwest have adopted the use of production cost studies that**
15 **employ historical water conditions for normalization.**

16 A. In any hydroelectric-oriented utility system, water supply is one of the major
17 variables affecting power supply. The operation of the thermal electric resources,
18 both within and outside the Pacific Northwest, is directly affected by water
19 conditions within the Pacific Northwest. During periods when the stream flows
20 are at their lowest, it is necessary for utilities to operate their thermal electric
21 resources at a higher level or purchase more from the market, thereby experiencing
22 relatively high operating expenses. Conversely, under conditions of high stream
23 flows, excess hydroelectric production may be used to reduce generation at the

1 more expensive thermal electric plants, which in turn results in lower operating
2 expenses for some utilities and an increase in the revenues of other utilities, or any
3 combination thereof. No one water condition can be used to simulate all the
4 variables that are met under normal operating conditions. Utilities and regulatory
5 commissions have therefore adopted production cost analyses that simulate the
6 operation of the entire system using historical water conditions, as being
7 representative of what can reasonably be expected to occur.

8 **VISTA Model**

9 **Q. What is the VISTA model?**

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

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

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

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

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

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

16 **Q. Do other utilities use the VISTA DSS model?**

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

19 **Q. Please describe the VISTA model inputs.**

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

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

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

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

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

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

1 Joseph under 70 years of “modified” stream flow conditions. The modified hydro
2 flows are the flows developed as the “PNCA Headwater Payments Regulation
3 2004-05” file, also known as “The 2005 70 year Reg” file, completed in July 30,
4 2004 for hydro conditions that actually occurred for the period 1928 through
5 1997. Thus the inflows to the Mid-Columbia projects are the result of extensive
6 modeling that reflects the current operations and constraints of the Columbia
7 River. These stream flow data are the most current information available to the
8 Company and serve as an input to the VISTA model. As in the case of the
9 Company’s large plants, the energy production resulting from the set of stream
10 flows is analyzed statistically to produce a set of probability curves or exceedence
11 levels for each group/week.

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

14 **Q. Please describe the VISTA model’s output.**

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

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

2 A. As stated earlier, the Company's filing, which uses a 40-year rolling average is
3 consistent with the Commission precedent from Docket No. UE-921262. To
4 accomplish this, the Company ran the VISTA model forty times with a single
5 year's historic conditions versus running the VISTA model with a complete set of
6 hydro conditions. For example, the Lewis River 1964 stream flow data was input
7 into the VISTA model. The VISTA model shaped that stream flow into weekly
8 energy/capacity availability subject to parameters described earlier. This process
9 is performed 40 times for the Mid-Columbia contracts, 40 times for the large
10 Company-owned projects, and 40 times for the small Company-owned projects.
11 As stated earlier in the description of the hydroelectric generation input data, the
12 40 sets of VISTA output are the hydro inputs to the GRID model.

13 **GRID Model Outputs**

14 **Q. What variables are calculated from the production cost study?**

15 A. These variables are:

- 16 • Dispatch of firm wholesale sales and purchase contracts;
- 17 • Dispatch of hydroelectric generation;
- 18 • Operating Reserve requirement, both contingent (spinning and ready) and
19 regulating;
- 20 • Allocation of operating reserve requirement to generating units;
- 21 • The amount of thermal generation required; and
- 22 • System balancing wholesale sales and purchases and optimization
23 transactions.

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

2 A. The major output from the GRID model is the Net Power Cost report. Additional
3 data with more detailed analyses are also available in hourly, daily, monthly and
4 annual formats by heavy load hours and light load hours.

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

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

11 **Q. Please describe Exhibit No. ____ (MTW-2).**

12 A. This Exhibit is a schedule of the Company's major sources of energy supply by
13 major source of supply, expressed in average megawatts owned and contracted for
14 by the Company to meet west control area load requirements, for the pro forma
15 period. The total shown on line 11 represents the total future usage of resources
16 during the pro forma period to serve west control area load. Line 12 consists of
17 wholesales sales made to neighboring utilities within the Pacific Northwest and the
18 Pacific Southwest as calculated from the production cost model study. Line 13
19 represents the Company's west control area load net of special sales.

20 **Q. Please describe Exhibit No. ____ (MTW-3).**

21 A. This Exhibit lists the major sources of future peak generation capability for the
22 Company's west control area winter and summer peak loads and the Company's
23 energy load for the pro forma period.

1 **PCAM**

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

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

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

13
14 The Commission further stated that:

15 We encourage the Company to work with Staff and intervenors to develop
16 a PCAM in line with the discussion above. Following discussions with
17 Staff and intervenors, the company may submit a revised PCAM proposal
18

19
20 **Q. Has the Company addressed the concerns raised by the Commission and had**
21 **discussions with Staff and intervenors?**

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

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

27 A. We are requesting a PCAM to protect the Company and customers from the net
28 power cost volatility related to the west control area. This volatility has been due

1 in large part to the generation volatility of owned and contracted hydro
2 generation. For the test period, normalized hydro generation produces 17.9
3 percent of the Company's west control area load requirement. Of course, other
4 factors such as market price volatility, weather conditions, forced outages for
5 generation and transmission facilities, planned outages and the economy also
6 affect the volatility of net power costs.

7 **Q. Please explain the information shown on Exhibit No.__(MTW- 4).**

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

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

13 A. No. While the potential causes of net power cost volatility have always been
14 present, the cost of addressing these factors has increased dramatically. Based on
15 2005 market prices at the Mid-C wholesale market hub and the hydro generation
16 difference shown in Exhibit No. __(MTW-4), net power costs could swing by
17 \$215 million for the west control area hydro generation volatility, notwithstanding
18 wholesale market price changes associated with extreme conditions and other
19 factors that cause volatility. Historical market prices are shown in Exhibit
20 No.__(MTW-5).

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

22 A. Wholesale market prices are expected to increase over 2006 levels before they
23 begin a slight decline that continues through 2013/2014, when they begin a

1 gradual increase. However, it is worth noting that the expected level of volatility
2 is quite high over a substantial portion of this period, which demonstrates the need
3 for a PCAM to capture the impacts of this volatility. Exhibit No.__(MTW-6) is
4 the Company's Official Price Projection of future market prices.

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

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

10 **PCAM Structure**

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

12 A. The PCAM is an incentive-based mechanism that would share variations in the
13 sum of adjusted actual variable net power costs and actual fixed production costs
14 from the sum of authorized variable net power costs and fixed production costs in
15 rates. The costs would be subject to a symmetrical deadband of plus or minus
16 \$3.0 million and sharing bands from greater than plus or minus \$3.0 million to
17 \$7.4 million and greater than plus or minus \$7.4 million, all on a Washington
18 basis. The Company would bear all cost variances within the deadband. Costs
19 that fall within the first sharing band would be split 60%/40% between customers
20 and Company and costs that fall within the second sharing band would be shared
21 90%/10% between customers and Company.

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

23 A. The Company designed the deadband and sharing bands to provide a reasonable

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

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

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

12 **Q. Please define authorized variable net power costs.**

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

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

23 A. In order to meet the Commission's directive to include only short-term costs

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

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

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

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

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

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

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

22 **Q. Please explain the treatment of major plant outages.**

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

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

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

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

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

19 A. Exhibit No. ___ (MTW-7) is a simple illustration of the Company's proposed
20 PCAM deferral calculation. As shown, each month the authorized variable net
21 power costs in rates is allocated to Washington and then divided by Washington
22 retail load in rates to convert the amount in rates to a \$/MWh basis. The same
23 calculation is also performed for the adjusted actual net power costs. The

1 difference between authorized variable net power costs in rates and adjusted
2 actual net power costs on a \$/MWh basis is then multiplied by the Washington
3 retail load in rates to determine the amount that is subject to the treatment of the
4 deadband and sharing bands to calculate the monthly deferral. This calculation
5 occurs each month of the measurement period to determine the deferral for
6 variable net power costs. The cost deferral associated with the difference between
7 fixed production costs in rates and actual fixed production costs is calculated in
8 the same manner as the variable net power cost component, except it is calculated
9 only once per year at the end of each measurement period. The PCAM deferred
10 balance is the sum of deferred balances for the variable net power cost and fixed
11 production cost components.

12 **Q. Does the deferred balance accrue interest?**

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

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

17 A. The Company will make a filing on an annual basis for review of deferred
18 balances, so that review of the deferred calculation does not accumulate into an
19 extremely large amount of processing workload for a future period. Recovery of
20 or return of deferred balances to customers should occur on an annual basis, as
21 long as a plus or minus \$3 million balance threshold has been exceeded at the end
22 of the measurement period. If the balance is less than the threshold, it will
23 continue to accrue interest until the end of the next measurement period, when the

1 balance will be compared to the threshold again. This process will continue until
2 the threshold is exceeded. This will reduce the frequency of rate changes during
3 periods of lesser cost volatility but still provide proper price signals to customers.

4 **Q. Should accrued costs be subject to a review?**

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

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

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

11 **Hydro Deferral**

12 **Q. When does the company expect to file for recovery of costs deferred during
13 2005 and 2006 for poor hydro conditions?**

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

16 **Q. Does this conclude your direct testimony?**

17 A. Yes.

18