

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

3 A. My name is Mark Widmer, my business address is 825 N.E. Multnomah, Suite
4 800, Portland, Oregon 97232, and my present position is Principal System
5 Planner.

6 **Qualifications**

7 Q. Briefly describe your education and business experience.

8 A. I received an undergraduate degree in Business Administration from Oregon State
9 University. I have worked for PacifiCorp since 1980 and have held various
10 positions in the power supply and regulatory areas. I was promoted to my present
11 position in 1998.

12 Q. Please describe your current duties.

13 A. I am responsible for the coordination and preparation of net power cost and
14 related analyses used in retail price filings. In addition, I represent the Company
15 on power resource and other various issues with intervenor and regulatory groups
16 associated with the six state regulatory commissions to whose jurisdiction we are
17 subject.

18 **Summary of Testimony**

19 Q. Will you please summarize your testimony?

20 A. I will present the results of the production cost model study for the normalized
21 and adjusted 1999 test year. I will describe the major causes of the significant
22 increases in the Company's net power costs since the last Utah rate case in Docket
23 No. 99-035-10. I will also describe the alternative methodology to PD/Mac used

1 to calculate net power costs, as well as provide information on how input data is
2 normalized in the Company's production cost model and the rationale for doing
3 so. I also address certain normalizing adjustments contained in Exhibit UP&L
4 ____1 (DDL-1), which is the Company's Utah Results of Operations Report for
5 the twelve-month test period ended December 31, 1999. Specifically, my
6 testimony explains normalizing Adjustments 5.3 and 5.5.

7 **Net Power Cost Results**

8 Q. What are the results of the Company's 1999 normalized and adjusted test year net
9 power cost study?

10 A. The Company's 1999 normalized and adjusted net power costs are approximately
11 \$692 million on a Total Company basis.

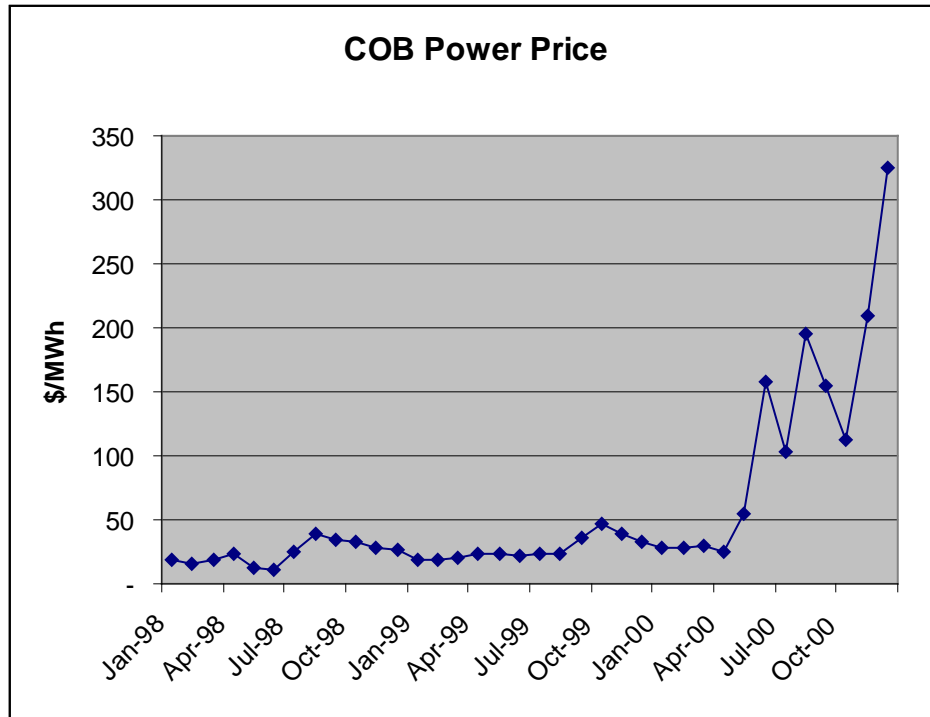
12 Q. How do those net power costs compare to the Company's 1998 normalized net
13 power costs from Utah Docket No. 99-035-10?

14 A. The proposed net power costs are approximately \$266 million higher on a Total
15 Company basis.

16 Q. Please explain the primary cause for the increase in net power costs.

17 A. The market price of power has skyrocketed at all the western region trading points
18 where the Company purchases power, such as the California-Oregon Border
19 (COB), Mid-Columbia (Mid-C), Palo Verde (PV), and the California Power
20 Exchange (CalPX). As shown in the chart below, COB power prices spiked up
21 from an average cost of \$36.69 per MWh in November 1999 to approximately
22 \$312 per MWh in December 2000. Prices at other trading points such as Mid-C

1 and PV have climbed steeply also. COB prices are cited to illustrate the
2 magnitude of recent changes in the market.



3 Looking forward, the COB forward power market is pricing power at an
4 even higher level for the entire twelve months ending December 2001 than
5 occurred during 2000. This unabated spike in power costs has rocked the
6 industry. Despite these high prices, Utah Power customers have been shielded by
7 PacifiCorp's stable tariffs from the extreme power costs.

8 Q. Does the electric energy market show signs of returning to historic price patterns?
9 A. No, not in the next year. Even more damaging than 2000 prices is the ominous
10 evidence that market power prices in 2001 are expected to be even higher.

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Table 1
COB 2001 Forward Price Curve (Flat)

<i>\$/MWh</i>	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Bid	\$532	\$384	\$315	\$176	\$149	\$165	\$201	\$248	\$230	\$108	\$113	\$112
Ask	\$395	\$292	\$265	\$140	\$118	\$133	\$182	\$224	\$208	\$87	\$92	\$90
Mid	\$464	\$338	\$290	\$158	\$134	\$149	\$192	\$236	\$219	\$97	\$102	\$101
Average Midpoint												\$207

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Over the next twelve months current market prices show an average monthly high of \$464 per MWh in January and a low of \$97 per MWh in October 2001. Certain daily and hourly prices are expected to exceed the monthly average. All this contrasts sharply with the average short-term market price of \$22.19 per MWh adopted in Utah Docket No. 99-035-10. Further, the replacement power to cover the outage at Hunter 1, which is not a part of this request, is approximately \$61 million for December 2000 alone. The Total Company impact related to all purchased power costs is huge.

Q. What has driven electricity prices so high?

A. There has been much speculation and analysis regarding the cause of high market prices but the exact causes have yet to be determined. A combination of high gas prices and significant growth in electricity demand coupled with little new generation capacity, CalPX price caps and generation limits due to emission credits has certainly contributed to the high market prices experienced throughout the West during 2000. Until these problems are resolved, there is no reason to expect that market prices will stabilize at significantly lower levels. What is clear is that the price increase is extraordinary and is driven by forces beyond management control.

1 Q. Has the Company's resource portfolio helped protect its customers from the full
2 impact of wholesale price increases?

3 A. Yes. The Company has not had to rely on market purchases to meet load
4 requirements to the same extent as other utilities.

5 Q. What is the Company doing in response to these conditions?

6 A. The Company has adopted a prudent strategy to hedge against market price
7 volatility. These efforts include the exploration of load management opportunities
8 as well as buying power on the forward market to cover a portion of the
9 Company's short positions.

10 **Determination of Net Power Cost**

11 Q. Are the proposed net power costs developed in a manner consistent with previous
12 determinations?

13 A. Yes, with the exception of the Company's net power cost model. As ordered by
14 the Public Service Commission of Utah in Docket No. 99-035-10, the Company
15 did not use PD/Mac to calculate the Net Power Cost in this docket.

16 Q. Please explain how net power costs were calculated.

17 A. The Company calculated net power costs on a normalized and adjusted basis
18 using a spreadsheet model, as an alternative to PD/Mac. The model is used to
19 simulate the operation of the power supply portion of the Company under a
20 variety of stream flow conditions. The results obtained from the various stream
21 flow conditions are averaged and the appropriate cost data is applied to determine
22 an expected net power cost under normal stream flow and weather conditions for
23 the test period.

1 Q. Please explain the how the production cost model estimates net power costs.

2 A. The development of expected net power costs begins with the selection of either a
3 forecast or historic test period. My testimony will focus on the use of a historical
4 test year. I have divided the description of the power cost model into three
5 categories:

6 1. The model used to calculate the net power costs.

7 2. The inputs that go into the model.

8 3. The output provided by the model.

9 **Alternative Methodology to PD/Mac**

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

12 A. The net power costs are calculated on a monthly basis. The general steps are as
13 follows:

14 1. Determine the temperature adjusted retail load.

15 2. Determine the level of thermal generation, based on normalized availability
16 and maintenance. Thermal generation is displaced if lower cost purchases are
17 available.

18 3. Calculate the thermal generation expenses using the normalized fuel costs.

19 4. Determine both the energy amount and expenses (revenues) of long term and
20 short term firm wholesale purchases (sales).

21 5. Determine the wheeling expenses.

22 6. Determine the level of hydro generation, based on the 50 water-year records.

1 7. For every month of every water year, calculate the system balances on both
2 east and west sides of the Company's system.

3 8. Buy secondary energy if there is a deficit, and sell secondary energy if there is
4 a surplus.

5 Q. What are the components of the net power costs?

6 A. Net power cost are defined as the sum of fuel expenses, wholesale purchase
7 expenses and wheeling expenses, less wholesale sales revenue. With the
8 exception of secondary purchase expenses and secondary sales revenue, all the
9 components have been calculated by steps 3 through 5 above.

10 Q. Please describe how secondary purchases and sales are incorporated in the net
11 power costs.

12 A. After steps 7 and 8, for each month there are 50 secondary purchase volumes and
13 sales volumes, one corresponding to a water year. The secondary purchase
14 volumes are averaged to obtain normalized secondary purchase volume, and the
15 secondary sales volumes are averaged to obtain normalized secondary sales
16 volume. The normalized purchase and sale volumes are then multiplied by
17 secondary purchase and sale prices, respectively, to determine secondary purchase
18 expense and secondary sales revenue. They are added to the corresponding
19 components in the net power costs.

20 **Model Inputs**

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

22 A. As mentioned above, inputs into the production cost model include retail loads,
23 thermal plant data, hydroelectric generation data, firm wholesale sales, firm

1 wholesale purchases, firm wheeling expenses, and nonfirm wholesale sales and
2 purchase market data.

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

4 A. The retail load represents the monthly firm retail loads that the Company served
5 within all of its jurisdictions for the twelve-month period ended December 31,
6 1999. These loads have been adjusted to reflect normal temperature conditions.

7 Q. Please describe the thermal plant input data.

8 A. The amount of energy available from each thermal unit and the unit cost of the
9 energy are needed to calculate net power costs. To determine the amount of
10 energy available, the Company averages for each unit, four years of historical
11 operating equivalent availability reduced by the four-year average maintenance.

12 The unit cost of energy for each unit is determined by using a four-year average of
13 historical burn rate data. By using four-year averages for maintenance, historical
14 availability and burn rate data, annual fluctuations in unit operation and
15 performance are smoothed. The four-year period used by the Company for this
16 filing is 1996 through 1999.

17 Q. Please describe the hydroelectric generation input data.

18 A. Fifty years of monthly hydroelectric generation for Company-owned hydro plants
19 in the Northwest and Mid-Columbia purchased resources are input into the model.

20 The hydro data that is input into the production cost model is from the Bonneville
21 Power Administration (BPA) Hydro Regulation computer program (Hydro
22 Regulation). Data from Hydro Regulation is based on actual stream flows for the
23 period August 1928 through July 1978. Hydro Regulation simulates the

1 hydroelectric generation at each facility on the major rivers in the Pacific
2 Northwest based on inputs provided by each member of the Northwest Power
3 Pool, Idaho Power Company, and the Assured Operating Plan of the Canadian
4 Utilities. The purpose of Hydro Regulation is to maximize the firm energy
5 capability of the Pacific Northwest hydroelectric system. It is based on
6 hydroelectric plant efficiencies, storage capabilities and requirements, minimum
7 flow requirements (including fish requirements), regional loads and resources, and
8 non-power operating constraints.

9 Q. Is the input of hydro generation located outside of the Northwest modeled in the
10 same manner as the Pacific Northwest hydro generation?

11 A. No. The input of hydro generation located in Utah and Southeast Idaho was
12 calculated as the actual average monthly hydroelectric generation for the years
13 1974 through 1999. A shorter time frame is used for the Utah and Southeast
14 Idaho hydro resources than the Company's other hydro resources because their
15 relative size is small, there is no overall area model analogous to the Hydro
16 Regulation model in the Northwest and there is a lack of reliable data for the
17 earlier years.

18 Q. Please describe the input data for firm wholesale sales, purchases, and wheeling
19 expenses.

20 A. The data for firm wholesale sales, purchases, and wheeling are all based on
21 contracts to which the Company is a party. Each contract specifies the basis of
22 quantity and price. The contract may specify an exact quantity of capacity and
23 energy or a range bounded by a maximum and minimum amount, or it may be

1 based on the actual operation of a specific facility. Prices may also be specifically
2 stated, may refer to a rate schedule, a market index such as COB or PaloVerde, or
3 may be based on some type of formula.

4 Q. Please describe the nonfirm wholesale sales and purchase input assumptions.

5 A. The production cost model requires inputs relating to four non-firm wholesale
6 sales markets. There are two markets in the calculation: east and west. As a result
7 of the significant increase in wholesale market prices that occurred in 2000 and
8 the expectation that high prices will continue, short-term wholesale sales and
9 purchase prices are based on actual prices as reported by Dow Jones for the period
10 January 2000 through first half of December 2000 and a Company estimate for the
11 second half of December 2000.

12 **Normalization**

13 Q. Please explain what is meant by normalization and how it applies to the
14 production cost model for historical test years.

15 A. Normalization for a historical test year is the process of modifying actual test year
16 data by removing all known abnormalities and making adjustments for all known
17 changes. Normalization produces test year results that are representative of
18 expected conditions with none of the abnormalities that occur in each actual year.
19 The availability of energy from Company-owned and purchased hydroelectric
20 generation is normalized by running the production cost model for each of the 50
21 different water years identified in the Hydro Regulation.

22 Q. You stated that hydroelectric generation is normalized by using historical water
23 data. Please explain why the regulatory commissions and the utilities of the

1 Pacific Northwest have adopted the use of production cost studies that employ
2 historical water conditions for making these normalization adjustments.

3 A. In any hydroelectric-oriented utility system, water supply is one of the major
4 variables affecting power supply. The operation of the thermal electric resources
5 both within and outside the Pacific Northwest are directly affected by water
6 conditions within the Pacific Northwest. During periods when the stream flows
7 are at their lowest, it is necessary for utilities to operate their thermal electric
8 resources at a higher level or purchase more from the market, thereby
9 experiencing relatively high operating expenses. Conversely, under conditions of
10 high stream flows, excess hydroelectric production may be used to reduce
11 generation at the more expensive thermal electric plants, which in turn results in
12 lower operating expenses for some utilities and an increase in the revenues of
13 other utilities, or any combination thereof. No one water condition can be used to
14 simulate all the variables that are met under normal operating conditions. Utilities
15 and regulatory commissions, therefore, have adopted production cost analysis that
16 simulates the operation of the entire system using historical water conditions, as
17 being representative of what can reasonably be expected to occur.

18 **Model Outputs**

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

20 A. These variables are:

- 21 1. The amount of thermal generation required;
- 22 2. Secondary sales on the east and west sides of the Company's system;

1 3. The secondary energy purchased on the east and west sides of the
2 Company's system.

3 Q. Do you believe that the production cost model appropriately represents the
4 Company's operating relationship with the other utilities and markets?

5 A. Yes.

6 Q. Please describe Exhibit UP&L __.1 (MTW-1).

7 A. Exhibit UP&L __.1 (MTW-1) is a schedule of the Company's major sources of
8 energy supply by major source of supply, expressed in average megawatts, owned
9 and contracted for by the Company to meet system load requirements, for the
10 normalized and adjusted 1999 test period. The total shown on line 14, represents
11 the total normalized usage of resources during the test period to serve system load.
12 Line 15 consists of wholesales sales made to neighboring utilities within the
13 Pacific Northwest, the Pacific Southwest, and the Desert Southwest as calculated
14 from the production cost model study. Line 16 represents the Company's System
15 Load net of special sales.

16 Q. Please describe Exhibit UP&L __.2 (MTW-2).

17 A. Exhibit UP&L __.2 (MTW-2) lists the major sources of peak generation
18 capability for the Company's winter and summer peak loads and the Company's
19 energy load for the normalized and adjusted 1999 test period.

20 Q. How are the results of the production cost study used in this rate proceeding?

21 A. The resulting purchased power expense, fuel and wheeling expenses and
22 wholesale sales revenues are included in Mr. Larson's Exhibit UP&L __.1 (DDL-
23 1).

1 **Normalizing Adjustments**

2 Q. Please explain Net Power Cost adjustments 5.3 and 5.5 contained in Tab 5 of
3 Exhibit UP&L ____1 (DDL-1).

4 A. **Sacramento Municipal Utility District (SMUD) Revenue Imputation**
5 (Adjustment 5.3) - In Docket No. 99-035-10, the Commission imputed the
6 Southern California Edison (SCE) contract rate of \$37 per MWH to the SMUD
7 contract. Adjustment 5.3 imputes sales for resale revenues to reflect the ordered
8 rate, thus increasing Utah revenues by \$2,840,700.

9 **Wholesale Contract Revenue Imputation** (Adjustment 5.5) - In Docket No. 99-
10 035-10 the Commission ordered the Company to impute revenues on six
11 wholesale contracts. Two of the contracts expired during the test period and were
12 normalized out. Adjustment 5.5 imputes revenues on the remaining four
13 contracts which increases Utah revenues by \$252,718.

14 Q. Does this conclude your direct testimony?

15 A. Yes.