825 N.E. Multnomah
Portland, Oregon 97232
(503) 813-5000

PACIFICORP
PACIFIC POWER UTAH POWER

April 15, 2005

Oregon Public Utility Commission
550 Capitol Street NE, Suite 215
Salem, OR 97301-2551

Attn: Vikie Bailey-Goggins Administrator
Regulatory and Technical Support

RE: Case No. UM-

PacifiCorp (dba Pacific Power & Light Company) submits for filing an original and twenty conformed copies of the Application of PacifiCorp for Approval of Power Cost Adjustment Mechanism, ("PCAM") along with supporting testimony and exhibits.

It is respectfully requested that all formal correspondence and staff requests regarding this matter be addressed to:

By E-mail (preferred):	datarequest@pacificorp.com.
By Fax:	(503) 813-6060
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 800 Portland, OR 97232
With copies to:	Katherine A. McDowell Stoel Rives LLP 900 S.W. Fifth Ave., Suite 2600 Portland, OR 97204 Telephone Nos. (503) 294-9602 Fax No. (503) 220-2480 Email: kamcdowell@stoel.com

Informal inquiries may also be made to Laura Beane at (503) 813-5542.

Very truly yours,

D. Douglas Larson

D. Douglas Larson
Vice President, Regulation

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION OF THE STATE OF OREGON

PACIFICORP

Power Cost Adjustment Mechanism ("PCAM")

Direct Testimony and Exhibits

April 2005

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM _____

In the Matter of the Application of PACIFICORP for an Order Approving an Automatic Adjustment Clause Related to Net Power Costs	**APPLICATION**

I. INTRODUCTION

Through this Application and supporting testimony, PacifiCorp, or ("the Company") is proposing to establish a power cost adjustment mechanism ("PCAM"). The proposed mechanism is intended to better balance, between the Company and its customers, the risk that actual net power costs will differ from the level forecast in setting general rate levels. The proposed PCAM is an "automatic adjustment clause" as contemplated by ORS 757.210(1).

It has likely always been the case that the Company's actual net power costs have proven to be higher or lower than the level predicted in general rate proceedings. Historically, the Company's shareholders have borne the risk that actual net power costs are higher than predicted and its customers have borne the risk that actual net power costs are lower than predicted. Prior to the 2000/2001 Western energy crisis, the degree of variability of net power costs from the forecasted level did not give rise to an unreasonable level of risk for either shareholders or customers. That is no longer the case. Over the last five years, the Company has experienced extraordinary variability in wholesale market prices for gas and electricity which have resulted in extraordinary variability in its net power costs. High wholesale market prices and high wholesale market price variability are expected to continue into the future.

Moreover, this variability has proven to be asymmetric. Net power cost overruns have vastly exceeded underrruns. Because of this lack of symmetry, in the absence of a

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PCAM, the Company will be effectively denied a reasonable opportunity to earn its allowed rate of return.

II. NOTICE AND EXHIBITS

Communications regarding this Application should be addressed to:

Laura Beane
Oregon State Manager
PacifiCorp
825 NE Multnomah, Suite 800
Portland, OR 97232
Telephone: (503) 813-5542
Facsimile: (503) 813-6060
E-mail: laura.beane@pacificorp.com

George M. Galloway Attorney at Law PO Box 184 Cove, OR 97824 Telephone: (541) 420-3246 E-mail:covelaw@direcway.com	Katherine McDowell Stoel Rives 900 SW 5th #2600 Portland, OR 97204-1268 Telephone: (503) 294-9602 E-mail: kamcdowell@stoel.com

In addition, PacifiCorp respectfully requests that all data requests regarding this matter be addressed to:

By email (preferred)	datarequest@pacificorp.com
By regular mail	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 800 Portland, OR 97232
By facsimile	(503) 813-6060

Proposed Schedule 99, describing the PCAM, is attached to this Application as Exhibit A. A copy of the Notice of Application and a list of persons served with the Notice are attached to this Application as Exhibit B.

III. STRUCTURE OF PROPOSED PCAM

A. Sharing Bands

The proposed PCAM is an incentive-based mechanism that would share variations in adjusted actual net power costs from the baseline forecast net power costs in rates, with one exception. The one exception is that 100 percent of cost increases or decreases related to Qualifying Facility contracts would be exempted from the sharing bands because the purchases are required by PURPA. All other costs would be subject to symmetrical sharing bands, which straddle "baseline net power costs" in rates. When "actual adjusted net power costs" are within plus or minus $100 million, total Company, the increment would be allocated 70 percent to customers and 30 percent to the Company. When the increments exceed plus or minus $100 million total Company, the increment would be allocated 90 percent to customers and 10 percent to the Company so as to provide catastrophic protection. The accruals will be allocated to Oregon pursuant to the Revised Protocol previously ratified by the Commission.

"Baseline net power costs" will be the net power costs adopted from the Company's annual Transition Adjustment mechanism or rates in effect during the measurement period. The Transition Adjustment mechanism includes an annual update of the Company's net power costs and is a component of the Company's general rate case (UE-170), which is currently being processed by the Commission. Measurement periods will be tied to the balancing account trigger.

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"Actual adjusted net power costs" will be equal to actual net power costs, adjusted to remove prior-period adjustments recorded during the accrual period and to include Commission-adopted adjustments from the most recent rate case. For example, actual results would be adjusted to reflect the Commission-adopted Sacramento Municipal Utility District (SMUD) wholesale sale revenue imputation adjustment. Conversely, hydro normalization and forced outage rate adjustments would be excluded.

B. Accruals

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

The Company further proposes that a plus or minus $15 million accrued balance be established as a trigger. Once the trigger is reached, the Company will be required to return the balance to, or request recovery from, customers. This approach is believed to be more beneficial than setting a fixed period because it should reduce the amount of rate changes during periods of lower net power cost volatility and reduce rate shock during periods of higher volatility when balances could be much higher. It will also provide more current price signals during periods of higher net

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power cost volatility. The amortization period should be over a one-year period or such longer period as required to comply with ORS 757.259.

C. Costs That are Included

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

D. Rate Spread and Rate Design

As proposed in Schedule 99, sur-charges and sur-credits will be spread to customers on a uniform cents-per-kwh basis to all customer classes in order to reflect changes in costs per MWh incurred by the Company to serve customers. Because differences in delivery voltage result in different line losses and power requirements, the Company proposes to vary the sur-charge and or sur-credit amounts by delivery voltage. The loss factors in effect at the time of the accrual would be used for this determination.

E. Earnings Test

If the Company's actual rate of return shown in its most recent semi-annual report was above authorized levels, costs accrued during that period would not be

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recoverable. Conversely, if earned rates of return were below authorized levels, accrued balances owed to customers would not be returned.

IV. A PCAM IS A REASONABLE AND APPROPRIATE MEANS OF BETTER BALANCING RISK

From 2000 through 2004, the average annual deviation between the Company's forecasted and actual net power costs was $135.5 million in excess costs, or 19.95 percent of authorized net power costs. During the prior ten-year period, the average variability was 2.62 percent of authorized net power costs. The current level of net power cost variability presents an unacceptable level of risk for the Company and its customers. Moreover, because the variability in actual net power costs is asymmetric, in the absence of a PCAM, the Company will not have a reasonable opportunity to recover its costs and earn its allowed rate of return.

The proposed PCAM will ensure that, in the future, the Company's prices more accurately capture the actual underlying cost of providing service to its customers. Without a PCAM, the magnitude of the harm that PacifiCorp faces would require it to seek other regulatory relief, which could increase the frequency of fluctuations in rate levels. Conversely, the PCAM will lead to greater rate stability.

Moreover, the proposed PCAM should improve the Company's credit standing and lower the level of debt imputation associated with purchased power contracts, thereby making such contracts more attractive to the Company and its customers.

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V. PENDING HYDRO-DEFERRAL APPLICATION

If approved by the Commission, the PCAM would incorporate the Company's proposed hydro deferral that is pending before the Commission in UM 1193 and replace it on a going forward basis.

VI. CONCLUSION

PacifiCorp respectfully requests that, in accordance with ORS 757.205 and ORS 757.210, the Commission find that the proposed PCAM is fair, just and reasonable and approve proposed Schedule 99.

DATED: April 15, 2005

STOEL RIVES, LLP

Katherine A. McDowell

GEORGE M. GALLOWAY
ATTORNEY AT LAW

George M. Galloway

Attorneys for PacifiCorp

Case UM –
PPL Exhibit A

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit A

Schedule 99

Power Cost Adjustment Mechanism

April 2005

(N)

Power Cost Adjustment Mechanism

A. Sharing Bands

The PCAM is an incentive-based mechanism that shares variations in adjusted actual net power costs from the baseline forecast net power costs in rates, with one exception. The one exception is that 100 percent of cost increases or decreases related to Qualifying Facility contracts are exempted from the sharing bands because the purchases are required by PURPA. All other costs are subject to symmetrical sharing bands, which straddle "baseline net power costs" in rates. When "actual adjusted net power costs" are within plus or minus $100 million, total Company, the increment is allocated 70 percent to customers and 30 percent to the Company. When the increments exceed plus or minus $100 million total Company, the increment is allocated 90 percent to customers and 10 percent to the Company so as to provide catastrophic protection. The deferrals are allocated to Oregon pursuant to the Multi-State Process allocation principles set forth in the Revised Protocol previously ratified by the Commission.

"Baseline net power costs" are the net power costs adopted from the Company's annual Transition Adjustment mechanism or rates in effect during the measurement period. Measurement periods will be tied to the balancing account trigger.

"Actual adjusted net power costs" are equal to actual net power costs, adjusted to remove prior-period adjustments recorded during the deferral period and to include Commission-adopted adjustments from the most recent rate case. For example, actual results are adjusted to reflect the Commission-adopted SMUD wholesale sale revenue imputation adjustment. Conversely, hydro normalization and forced outage rate adjustments are excluded.

B. Deferrals

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

A deferred balance of plus or minus $15 million is a trigger. Once the trigger is reached, the Company is required to return the balance to, or request recovery from, customers. The amortization period is over a one-year period or such longer period as required to comply with ORS 757.259.

C. Costs Included

The PCAM is designed to include all net power cost components. It reflects the impact of cost changes for fuel, wheeling and purchase power expenses and wholesale electricity and gas sales.

(continued)

(N)

(N)

Power Cost Adjustment Mechanism *(continued)*

D. Rate Spread and Rate Design

Sur-charges and sur-credits are spread to customers on a uniform cents-per-kwh basis to all customer classes in order to reflect changes in costs per MWh incurred by the Company to serve customers. Because differences in delivery voltage result in different line losses and power requirements, the sur-charge and or sur-credit varies by delivery voltage.

E. Earnings Test

If the Company's actual rate of return reflected in its most recent semi-annual report was above authorized levels, costs deferred during that period would not be recoverable. Conversely, if earned rates of return were below authorized levels, accrued balances owed to customers would not be returned.

F. Special Conditions

This schedule is an automatic adjustment clause as defined in ORS 757.210 and is subject to review by the Commission at least once every two years. The Company shall not be required to apply for reauthorization for its PCAM balancing account under ORS 757.259.

G. Term

The PCAM will continue until terminated.

H. Sur-charge/Sur-credit calculation

All bills calculated in accordance with applicable schedules contained in presently effective Tariff Or. No. 35 shall have applied an amount equal to the product of all kilowatt-hours of use multiplied by the following cents per kilowatt-hour.

		Delivery Voltage	
	Secondary	**Primary**	**Transmission**
Schedule 4	0.0 cents		
Schedule 15	0.0 cents		
Schedule 23, 723	0.0 cents	0.0 cents	
Schedule 28, 728	0.0 cents	0.0 cents	
Schedule 30, 730	0.0 cents	0.0 cents	
Schedule 41, 741	0.0 cents	0.0 cents	
Schedule 48, 748	0.0 cents	0.0 cents	0.0 cents

(N)

(continued)

(N)

Power Cost Adjustment Mechanism *(continued)*

H. Sur-charge/Sur-credit calculation *(continued)*

Schedule 50	0.0 cents
Schedule 51, 751	0.0 cents
Schedule 52, 752	0.0 cents
Schedule 53, 753	0.0 cents
Schedule 54, 754	0.0 cents

(N)

Case UM –
PPL Exhibit B

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit B

Notice of Application

April 2005

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM ______

In the Matter of the Application of PACIFICORP for an Order Approving an Automatic Adjustment Clause Related to Net Power Costs	NOTICE OF APPLICATION

On April 15, 2005, Applicant PacifiCorp applied to the Public Utility Commission of Oregon (the "Commission") for a power cost adjustment mechanism (PCAM). The PCAM proposes a balancing account to track actual power costs and an automatic adjustment clause under ORS 757.210(1).

Interested persons can obtain a copy of the Application by contacting:

Katherine A. McDowell
Stoel Rives LLP
900 SW Fifth Avenue, Suite 2600
Portland, OR 97204
Telephone: (503) 294-9602

Because the PCAM incorporates a balancing account, any person may submit to the Commission written comment on the Application, in accordance with procedures prescribed by the Commission. Under the Commission's administrative rules, the period for initial comments on the Application expires on May 13, 2005.

DATED: April 15, 2005

STOEL RIVES LLP

Katherine A. McDowell

GEORGE M. GALLOWAY
ATTORNEY AT LAW

George M. Galloway

Attorneys for PacifiCorp

STOEL RIVES LLP
900 SW Fifth Avenue, Suite 2600, Portland, OR 97204
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CERTIFICATE OF SERVICE

I hereby certify that I served the foregoing Notice of Application on the following named person(s) on the date indicated below by

☒ mailing with postage prepaid

☐ hand delivery

☐ facsimile transmission

☐ overnight delivery

to said person(s) a true copy thereof, contained in a sealed envelope, addressed to said person(s) at his or her last-known address(es) indicated below.

Stephanie S. Andrus
Department of Justice
Regulated Utility & Business Section
1162 Court Street, NE
Salem, OR 97301-4096

Ron Binz
333 Eudora Street, Suite 100
Denver, CO 80220-5721

Ken Canon
Industrial Customers of Northwest Utilities
825 NE Multnomah, Suite 180
Portland, OR 97232-2158

Ralph Cavanagh
Natural Resources Defense Council
111 Sutter Street, 20th Floor
San Francisco, CA 94104

Melinda J. Davison
Matthew W. Perkins
Davison Van Cleve
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Portland, OR 97204

J. Jeffrey Dudley
Portland General Electric
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Portland, OR 97204

Jason Eisdorfer
Lowrey R. Brown
Citizens' Utility Board of Oregon
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Portland, OR 97205

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Kurt Boehm
Boehm, Kurtz & Lowry
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Esler Stephens & Buckley
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Portland General Electric
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Community Action Directors of Oregon
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Edward Bartell
Klamath Off-Project Water Users, Inc.
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Sprague River, OR 97639

Phil Carver
Oregon Office of Energy
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Salem, OR 97301-3742

Joan Cote
Oregon Energy Coordinators Assoc.
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Salem, OR 97301

John Devoe
Lisa Brown
Waterwatch of Oregon
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Portland, OR 97204

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Robert Valdez
Judy Johnson
Public Utility Commission of Oregon
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Salem, OR 97308-2148

Glen H. Spain
PCFFA
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Eugene, OR 97440-3370

DATED: April 15, 2005.

Katherine A. McDowell

Of Attorneys for PacifiCorp

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Case UM-
PPL Exhibit 100
Witness: Christy A. Omohundro

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Christy A. Omohundro

Policy

April 2005

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

A. My name is Christy A. Omohundro. My business address is 825 NE Multnomah, Suite 800, Portland, Oregon, 97232. My present position with PacifiCorp is Managing Director, Regulation.

Qualifications

Q. Briefly describe your educational and professional background.

A. I hold a Master of Business Administration degree from Vanderbilt University as well as a Bachelor of Science degree in Accounting and Liberal Arts from Spring Hill College. I have worked for PacifiCorp since January 2002. Prior to assuming my present role in January 2002, I served for over nine years in various leadership roles with Puget Sound Energy, most recently as Director of Rates and Regulatory Policy. In that capacity, I was responsible for ongoing development of company regulatory policy, implementation of that policy through building relationships with regulators and their staffs, and integration of that policy with legislative, customer, and market strategies. In addition, I have experience with integrated resource planning and industry restructuring.

Q. What are your responsibilities as Managing Director, Regulation?

A. I am responsible for all state regulatory matters for the states of Oregon, Washington, and California.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. I will introduce the Company's proposed power cost adjustment mechanism

("PCAM") which, if authorized by the Commission, would reflect in rates, a portion of the variations in net power costs experienced by the Company. I will explain the reasons for the Company's request and discuss how PacifiCorp's proposed mechanism will return the Company to a reasonable level of earnings volatility and rebalance the overall interests of ratepayers and shareholders. I will also introduce the other witnesses providing direct testimony in this application.

Reasons for Request

Q. Why is the Company seeking to implement a PCAM at this time?

A. Since the Western energy crisis of 2000-2001, wholesale market prices have fluctuated tremendously, sometimes as much as five to ten times the prices experienced prior to early 2000. As a result, the Company's net power costs, which represent a large proportion of the Company's total operating costs and are largely outside of the Company's control, are subject to a large degree of volatility. The Company believes net power costs will continue to fluctuate in the future and believes that it is necessary to have a power cost recovery mechanism in order to allow changes in net power costs to be reflected between general rate cases.

Q. Please describe the significance of net power costs relative to the Company's total cost of service.

A. In the Company's general rate case pending before the Commission (UE-170), Oregon-allocated net power costs are approximately $236 million or 26 percent of the Company's total Oregon revenue requirement.

Credit Rating Implications

Q. Will the implementation of a PCAM positively influence the Company's overall credit rating?

A. Yes. The investment community and analysts monitoring the energy industry have identified the increased level of risk associated with the regulated energy environment. In response to the increased risk borne by regulated utilities participating in wholesale energy markets, the major credit rating agencies have begun imputing debt on company balance sheets for long-term power purchase agreements ("PPAs"). This debt imputation impacts the credit ratios of a company and, in some instances, may contribute to a credit downgrade.

In a recent Standard & Poor research article titled "Fuel and Power Adjusters Underpin Post-Crisis Credit Quality of Western Utilities", it states that PacifiCorp's lack of a fuel and purchased power adjustment mechanism is a credit concern (PPL Exhibit 101, page 2). Consistent with this statement, Standard & Poor has indicated in recent public presentations and in personal meetings with PacifiCorp that the risk factor used when evaluating PPAs will be significantly reduced if the Company has a reasonably structured PCAM in place.

Q. What does this mean for PacifiCorp?

A. If a PCAM is in place, PacifiCorp will be required to infuse less equity to offset the imputed debt impacts of PPAs on its balance sheet. This will not only help PacifiCorp to maintain its credit rating under its current supply portfolio, but will facilitate the development of the independent energy market by making PPAs less costly for customers.

When PacifiCorp acquires resources through its request for proposal ("RFP") process, debt imputation is a factor associated with the evaluation of energy options. Because debt is imputed for PPAs, the Company must also infuse a commensurate level of equity to balance its ratios to maintain its current credit rating. A lower risk factor associated with PacifiCorp's portfolio of PPAs will help to make purchased power more attractive relative to other options considered in the RFP process.

Q. Might the existence of a PCAM reduce Company management's incentive to optimally manage your portfolio in periods of high market prices?

A. No. The sharing applied to positive variances leaves a significant portion of risk with PacifiCorp and its shareholders. The Company and its management will have every incentive to continue to optimally manage our portfolio to avoid the risk associated with increases in net power costs. Furthermore, as testified to by Mr. Widmer, the collections under the PCAM will be subject to prudence review.

Q. PacifiCorp recently filed an application with the Commission requesting authorization to defer costs associated with low-hydro conditions. How will this filing impact that application?

A. If approved by the Commission, the PCAM would incorporate the Company's proposed hydro deferral that is pending before the Commission in UM 1193 and replace it on a going forward basis.

Introduction of Witnesses

Q. Please name additional witnesses and provide a brief description of their testimony.

A. The Company witnesses filing direct testimony are:

Mark T. Widmer, Director, Net Power Costs, will provide a detailed explanation of the Company's proposed PCAM and provide quantitative support for the Company's assertion of increased levels of risk.

Greg N. Duvall, Managing Director, Planning & Major Projects, describes the allocation methodology utilized in the PCAM to apportion net power cost variances to the Company's Oregon jurisdiction.

Q. Does this conclude your testimony?

A. Yes.

101 Omohundro Exhibit

Case UM –
PPL Exhibit 101
Witness: Christy A. Omohundro

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Christy A. Omohundro

"Fuel and Power Adjusters Underpin Post-Crisis Credit Quality of Western Utilities,"
by Standard & Poor

April 2005

Research:
Fuel and Power Adjusters Underpin Post-Crisis Credit Quality of Western Utilities

Publication date: 14-Oct-2004
Primary Credit Analyst(s): Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

It has been more than three years since the California energy crisis led to the rapid deterioration of credit quality for many western electric utilities. The financial distress that visited public power and investor-owned utilities (IOU) was in part attributable to the absence of fuel and purchased-power adjustment mechanisms (FPPA), coupled with a reliance on the wholesale market for significant supplies. It is not an oversimplification to say that IOUs that emerged relatively unharmed from the energy crisis benefited substantially from FPPAs, while those that suffered the most did not have FPPAs.

The severe market distortions of the California crisis have faded, but FPPAs continue to play a significant role in the financial well-being of western electric utilities. Natural gas volatility, poor hydro conditions in the Northwest, the Southwest's sustained drought, and uncertainty over future generation development are daily reminders that it is increasingly difficult for utilities to sustain their financial health solely through the use of hedging policies and regular general rate case filings. This article examines the progress by major western utilities in instituting FPPAs since the California crisis and comments on FPPA attributes that are important for credit quality.

What is an FPPA?

The overwhelming majority of a utility's expenses are concentrated in two categories--purchased power and fuel. Electric utilities that have the greatest exposure to significant cost swings are those that have sizable gas-fired generation and rely on power purchases that are indexed to market prices. Table 1 illustrates the proportion of 2003 expenses devoted to these two items for 12 western IOUs, and provides a measure of the dependence on gas and power purchases to meet load requirements.

Table 1 Largest IOUs in the West Without Fuel and Purchased-Power Adjusters

	Total fuel expenses (Mil. $) in 2003	Total purchased power expenses (Mil. $) in 2003	Percent of total expenses that is fuel and purchased power	Percent of retail sales supplied with own generation*	Percent of MWh from owned gas generation¶
Puget Sound Energy Inc.	65	649	35.2**	35.6	11.1
Avista Utilities/Avista Corp.	36	148	17.6**	73.8	7.4
Idaho Power/IDACORP Inc.	100	151	35.1	100.6	0.3§
Arizona Public Service/Pinnacle West Capital Corp.	703§§		36.1¶¶	84.5	4.9
Tucson Electric Power/UniSource Energy Corp.	210	65	34.4	136.9	4.0
PacifiCorp/PacifiCorp Holdings Inc.	482	1,213	50.5	107.7	4.1
Nevada Power Co./Sierra Pacific Resources	320	744	60.3	54.6	42.8
Sierra Pacific Power/Sierra Pacific Resources	321	745	53.1**	47.0	59.6
Portland General Electric Co.	1,028§§		60.2	43.0	17.3§

Public Service Co. of New Mexico	141	803	67.3**	134.4	2.1§
Southern California Edison Co.	235	2,786	39.2	63.7	-
Pacific Gas & Electric Co.	0	2,319	70.4**	36.0	1.7§
*Based on data provided by Platt's. ¶Based on company 10K filings, except where indicated by §, in which case data is provided by Platt's. **Combined utility (gas and electric). ¶¶Includes trading and marketing operations. §§Arizona Public Service and Portland General Electric fuel and power expenses are not separately broken out.					

An FPPA allows utilities to automatically flow through retail rates any changes in fuel and purchased-power costs. An FPPA circumvents the need for a utility to file a formal rate case to adjust retail rates to reflect changes in these costs, and significantly increases the probability that an IOU will collect fuel and power costs from ratepayers in full and on a much more timely basis. This is accomplished typically through monthly tracking of costs, with periodic true-ups of a utility's forecast versus actual fuel and power costs, typically annually.

Which Western IOUs Have Instituted FPPA?

In 2000, the largest IOUs in the western U.S. did not have FPPA, and their credit ratings generally suffered as a result of the market disruptions that occurred beginning in 2001 (See table 2) Today, the majority of western utilities have some form of FPPA.

Table 2 Fuel and Purchased-Power Adjusters

Utility/Holding Company	2000 Rating	FPPA in 2000?	2004 Rating	FPPA in 2004?
Puget Sound Energy Inc.	BBB+/Negative/A-2	No	BBB-/Positive/A-3	Yes
Avista Utilities/Avista Corp.	BBB/Negative/--	No	BB+/Stable/--	Yes
Idaho Power/IDACORP Inc.	A+/Stable/A-1	Yes	A-/Watch Neg/A-2	Yes
Arizona Public Service/Pinnacle West Capital Corp.	BBB+/Stable/A-2	No	BBB/Negative/A-2	No
Tucson Electric Power/UniSource Energy Corp.	BB/Stable/--	No	BB/Watch Neg/--	No
PacifiCorp/PacifiCorp Holdings Inc.	A/Stable/A-1	No	A-/Stable/A-2	No
Nevada Power Co. and Sierra Pacific Power/Sierra Pacific Resources	BBB+/Watch Neg/A-2	No	B+/Negative/--	Yes
Portland General Electric Co.	A/Watch Neg/A-1	No	BBB+/Watch Neg/A-2	Quasi
Public Service Co. of New Mexico	BBB-/Watch Neg	No	BBB/Stable/A-2	No
Southern California Edison Co.	A+/Watch Neg/A-1	No	BBB/Stable/A-2	Yes
Pacific Gas & Electric Co.	A+/Watch Neg/A-1	No	BBB-/Stable/--	Yes

Indeed, of the utilities surveyed by Standard & Poor's for this article, four companies have not implemented FPPA-- PacifiCorp (A-/Stable/A-2), Tucson Electric Power Co. (BB-/Watch Neg/--), Arizona Public Service Co. (APS; BBB/Negative/A-2), and Public Service Co. of New Mexico (BBB/Stable/A-2).

PacifiCorp serves portions of Utah, Oregon, Wyoming, Washington, Idaho, and California, has no FPPA in any of these states, and was adversely affected by the California crisis. As a result of an extended coal plant outage and overall reliance on the market for a portion of its power requirements, PacifiCorp deferred $537 million in power costs in 2001 and 2002, of which only $303 million were ultimately authorized for recovery, with Wyoming disallowing the bulk of this difference. As a result of this exposure, PacifiCorp's outlook was revised to negative, and the company was only recently returned to stable. While PacifiCorp has sought an FPPA in Wyoming, the Wyoming Public Service Commission has rejected its request, but did recently approve a settlement resulting from the company's July 2004 filing to increase rates due to rising wholesale power costs. Because about 21% of PacifiCorp's power in 2003 came from purchases, the lack of an FPPA is a credit concern.

In Arizona, the Arizona Corporation Commission (ACC) is allowed to authorize FPPA, but APS' and

Tucson Electric Power's were discontinued in the 1980s. As part of a settlement pending before the ACC, APS has negotiated an FPPA, which it requested in its June 2003 rate case filing. It is unclear whether the ACC will ultimately authorize one. APS' exposure to fuel and purchased-power is significant. In 2002, the ACC halted restructuring of the state's wholesale generation market. While it ordered APS not to sell its generation, APS was uncertain as to how it would procure power to meet retail loads. With electric sales rising about 4% per year, the utility estimates that by the summer of 2007, it will require a nearly 1,200 MW of new capacity, at least a portion of which is likely to be power purchases at indexed prices. Because of APS' significant short position in coming years, an FPPA could lower the utility's risk profile.

Since July 2000, Tucson Electric Power has been under a rate freeze that ends in 2008. Upward movement in gas or purchased power prices that exceeds its current rates does not qualify as sufficient reason to lift the cap. Tucson Electric Power's coal-fired generation provided 96% of the energy needed to serve retail load in 2003, and this low-cost resource base provides somewhat of a hedge against rapid cost escalation. However, a significant forced outage of one of its base load units or a run-up in coal prices with any coal contract reopeners represent exposures for the utility. (UniSource Energy Corp., Tucson Electric's parent, recently acquired the gas and electric distribution assets formerly owned by Citizens Communications. In conjunction with this purchase, the ACC approved an FPPA for these smaller operations, UNS Gas and UNS Electric.)

Public Service New Mexico faces circumstances similar to Tucson Electric Power's. It has no FPPA and in January 2003 negotiated a rate settlement that will lower rates 2.5% in 2005 and then hold rates constant until 2008. The utility owns generation that exceeds native loads, the majority of which is coal and nuclear.

FPPA Design and Implications for Credit Quality

While the use of FPPAs has become common, FPPAs are not uniform in design and consequently, their ability to protect utility credit quality varies. For example, some FPPAs are structured to insure cost recovery in a catastrophic market movement by capping a utility's exposure, but at the same time may have a relatively long lag time for a utility seeking to recover more mundane, month-over-month changes in costs. There are a number of features of FPPAs that are important for credit quality.

Triggers.

From a credit perspective, some of the strongest FPPA are found in the generation and transmission cooperative sector, where wholesale rates are often adjusted monthly. Such timely pass-through of fuel and purchased-power costs is rare in the IOU sector. Instead, IOU FPPA typically track costs in a balancing account, the amounts of which are not reflected in the retail rates as a charge or rebate until a predetermined threshold or trigger is hit. Clearly the lower the trigger, the more frequently the utility is able to adjust its rates to reflect cost changes.

Two contrasting examples can be found in California and Washington. In California, true-ups are not tied to an annual process. Assembly Bill 57, passed by the California state legislature in 2002, provides guidance to the California Public Utilities Commission (CPUC) as to how San Diego Gas & Electric Co., Pacific Gas & Electric Co., and Southern California Edison Co. are to recover procurement costs. Specifically, each year the utilities file their forecast fuel and purchased-power revenue requirements for CPUC review. (These forecasts exclude revenues collected for the California Department of Water Resource contracts). Once the forecast is approved, it is used to set rates. Deviations from the forecasts are tracked in a balancing account called the Energy Resource Recovery Account (ERRA). An adjustment to rates is triggered if the ERRA account is over- or undercollected by 5% of the utility's actual recorded generation revenues for the previous calendar year. This trigger, however, expires Jan. 1, 2006, after which there is uncertainty about what kind of mechanism will exist.

FPPAs may also be tied to dollar thresholds. The Washington Utility and Transportation Commission (WUTC) has approved an energy recovery mechanism for Avista Corp. that requires it to absorb the first $9 million of annual energy cost increases above base rates. Beyond this level, costs are deferred for later rebate and a surcharge is implemented when accumulated deferrals exceed 10% of base retail revenues. Alternatively, utilities may simply be subject to an annual reconciliation process in which actual versus forecast costs are used to adjust base rates. Idaho Power Co. (A-/Watch Neg/A-2) has such an approach.

Sharing mechanisms.

Commonly, FPPAs split the costs (savings) between the ratepayer and shareholder for fuel and purchased power that exceed a forecast range. For example, Puget Sound Energy Inc.'s FPPA requires that it absorb (or may benefit from) the first $20 million of increases (decreases) in actual versus forecast costs relative to baseline rates. For the next $40 million difference, 50% is borne by shareholders in the form of a FPPA adjustment, 10% of the next $80 million, and 5% of any amount more than $120 million, although through a temporary cap, Puget's exposure is limited through mid-2006.

Similarly, though more simply, APS' proposed power supply adjuster seeks a flat 90%/10% ratepayer/shareholder split in costs or savings. The same is true for Idaho Power's power cost adjustment. On balance, FPPAs that provide for fixed or high levels of ratepayer sharing are beneficial to credit quality because they trade upside benefit for downside protection.

Exposure caps.

Utility caps on losses are uncommon, but can be very useful for credit quality as they limit the utility's exposure resulting from extreme market volatility, which could otherwise erode financial health. For example, Public Service Co. of Colorado's (BBB/Stable/--) electric commodity adjustment limits the utility's maximum loss from fuel and purchased power expenses to $11.25 million. For the limited period from July 2002 through July 2006, the WUTC has provided Puget Sound Energy with a cap on its pretax exposure to purchased-power variations of a cumulative $40 million, plus 1% of the overage.

Prudency reviews.

Most FPPAs include caveats that allow the regulator to disallow costs if they are found to be imprudent. How complete this authority is determines how much the FPPA can be relied on, particularly in situations of extreme market volatility or when the utility is forced into the market to purchase replacement power to cover an owned plant outage. APS' proposed power supply adjuster is an example of a mechanism that gives regulators virtually unlimited authority to disallow costs. The ACC may elect to review the prudency of fuel and power purchases "at any time" and any costs flowed through the adjuster "shall be subject to refund if the Commission later determines that the costs were not prudently incurred."

By contrast, language that allows for prudency but provides the utility a high probability of recovery if certain guidelines are followed is preferable. One example is Nevada Power Co., whose recent experience with prudency disallowances of power purchases devastated its credit quality. Specifically, in March 2002, the Public Utilities Commission of Nevada disallowed $434 million of Nevada Power's purchased-power costs incurred during the energy crisis, causing the utility to lose access to bank lines of credit and to the unsecured credit markets. However, in November 2003, the PUCN approved an integrated resource plan (IRP) in which the company will get approval before entering into long-term PPAs. Its short-term power and fuel purchases are adjusted through a new base tariff energy rate, which has features that are similar to an FPPA. While base tariff energy rate costs are still subject to a prudence review, the IRP lays out clear risk-management guidelines, including value-at-risk limits and the use of certain derivative instruments that significantly mitigate the risks of disallowance if the company follows its IRP. Similarly, while California utilities could potentially face a reasonableness review along with its ERRA account, a disallowance is unlikely if the utility follows its procurement plans, which are preapproved by the CPUC.

How Quickly Recovery Is Collected in Retail Rates

Timeliness of recovery is important, as it can have implications for liquidity. California now has one of the strictest rules for timely response. The CPUC must act on a utility's request for an increase (assuming the trigger has been met) within 60 days of a filing. However, the CPUC has discretion in determining over what time period over- or under-collected balances are amortized.

In Arizona, deferrals could theoretically accumulate for long periods if amounts for collection exceed a surcharge cap but fall short of a safety net provision. If approved, APS' proposed PSA would be preset at a base rate of about 2.1 cents per kilowatt-hour (kWh). While actual costs above or below this level are tracked in a balancing account, true-ups occur only at year's end. At that time, rates are adjusted, but adjustments are constrained by the fact that they may not increase or decrease by more than 4 mills per kWh. However, APS may request the ACC to implement a special surcharge if the account reaches plus or minus $50 million at any time.

FPPA sunsets.

From a credit quality perspective, it is important to note that FPPAs are rarely established as a permanent component of a utility's rate structure. Thus, Standard & Poor's is mindful that FPPAs can be weakened or eliminated altogether once their initially authorized period expires. In the West, many of the FPPAs that have been implemented since 2002 have a sunset provision. For example, Puget Sound Energy, Public Service of Colorado, and California's three largest IOUs have FPPAs that expire Jan 1, 2006. If APS' proposal is approved, it will be in place for five years, at which time the ACC will conduct a review and determine whether it should continue. Another useful example is Portland General Electric Co. (BBB+/Watch Neg/A-2). The Oregon Public Utility Commission authorized a temporary FPPA to recover deferrals incurred in 2001 and 2002. The mechanism was discontinued in 2003. Today, the company has a quasi-FPPA; i.e., rates are updated annually through a resource valuation mechanism process, but if during the year the utility is unable to collect all of its costs through rates, it must make a special filing before the commission to recover the shortfalls. This experience highlights the fact that while many utilities may be currently protected through FPPA, this may not be the case for long.

Are FPPA the Holy Grail of Utility Credit Quality?

Standard & Poor's is frequently asked what weight is given to FPPA. It is clear that continued gas price volatility and upward trends in historically stable coal prices underscore the importance of FPPAs. Some western IOUs have sold their generation and will continue to rely on power purchases to meet retail load growth far into the future. However, it is also clear that FPPAs vary substantially in their ability to protect utilities daily and under catastrophic market movement. Moreover, it is critical to note that FPPAs are not a substitute for supportive regulation; the regulator's ability to disallow costs through ex-post prudency review, regardless of the existence of an FPPA, is a fact of life for utilities. But to the extent that an FPPA is transparent and well structured, regulators are likely to be less inclined to disallow a utility's fuel and purchased-power costs.

Case UM-
PPL Exhibit 200
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Mark T. Widmer

Net Power Costs

April 2005

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

A. My name is Mark Widmer, my business address is 825 N.E. Multnomah, Suite 800, Portland, Oregon 97232, and my present position is Director, Regulation.

Qualifications

Q. Briefly describe your education and business experience.

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

Q. Please describe your current duties.

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

Q. Have you previously testified in state regulatory proceedings?

A. Yes. I have testified in Oregon, Utah, Wyoming, Washington, Idaho and California on net power costs, avoided costs and direct access.

Summary of Testimony

Q. Will you please summarize your testimony?

A. I provide quantitative analysis of the Company's historical net power cost exposure and how that relationship has changed to the point that the Company's risk has become very asymmetrical. I present the Company's proposed power cost adjustment mechanism (PCAM), which if adopted, would better balance net power cost exposure between the Company and customers.

Asymmetric Risk

Q. Why is the Company requesting a PCAM?

A. The Company's net power cost exposure to losses is asymmetric. Costs can only fall to zero while cost increases are, theoretically, unlimited. While it is unlikely that costs will fall to zero or increase infinitely, the limitations are relevant. For example, as explained below, since 1989 the largest decrease in net power costs is dwarfed by the largest increase in net power costs above authorized levels. This is causing the Company to bear a disproportionate share of net power costs incurred to serve retail customers. As a consequence, our opportunity to earn our authorized rate of return over the long run will be greatly diminished if not eliminated, because net power costs are such a large component of revenue requirement.

Q. Please define net power cost exposure.

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

Q. Please explain the information shown on PPL Exhibit 201.

A. PPL Exhibit 201 shows historical net power cost exposure from 1990 through 2004 in Oregon. As shown, our net power cost exposure varied between an $83 million gain and a $267 million loss, calculated on a total Company basis. In aggregate, losses exceeded gains by approximately $570 million.

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

A. No. Beginning in 2000, with the start of the 2000-2001 energy crisis, the exposure has become very asymmetric toward losses. From 1990 through 1999, the exposure averaged ($10.7) million, or 2.62 percent of authorized net power costs and from 2000-2004 it averaged $135.5 million in excess costs, or 19.95 percent of authorized net power costs. In percentage terms, the exposure increased by over 1200 percent since 1999.

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

A. No. Deviations from authorized net power costs are primarily related to factors not controllable by the Company. For example, hydro conditions, weather conditions, wholesale market prices for natural gas and electricity and the timing of forced outages are not controllable. While these potential causes have always been present, the cost of addressing these factors has increased dramatically. The overwhelming cause of the cost increase is due to an increase in wholesale market prices and price volatility. For example, assume actual hydro generation for fiscal 2004 was 1.5 million MWh below normal. At market prices prevalent from 1990 through 1999, replacement power would have cost $25 million, on average. At 2004 average market prices, replacement power would have cost approximately $67 million. Historical market prices are shown in PPL Exhibit 202. Unless changes are made to the Company's Oregon regulatory structure, this asymmetry will continue to increase as wholesale market prices and price volatility increase.

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

A. While it is likely, that there will be some year-to-year volatility of wholesale market prices, the expected trend is up. PPL Exhibit 203 is the Company's Official Price Projection of future market prices.

Q. Have prudent steps been taken to insulate customers and shareholders from net power cost exposure?

A. Yes. The Company engages in integrated resource planning ("IRP"). Through the IRP process the Company identifies resource requirements which have resulted in the Company filing request for proposals ("RFPs") for resources to meet load requirements on a least-cost, risk-adjusted basis. This process provides further assurances to the Commission and customers as to the prudent nature of our net power costs involving power purchases and/or the construction of generation facilities. The Company has also increased its emphasis on transactions that would reduce risk. These efforts were undertaken to further align the interests of shareholders and customers. Finally, under the proposed PCAM described below, the sharing bands would result in the Company shouldering a significant portion of the volatility between rate cases, thereby reinforcing the Company's incentive to manage its system and associated risks prudently.

Q. Has net power cost exposure been recognized and addressed by other Commissions that regulate utilities located in Western Electricity Coordinating Council ("WECC")?

A. Yes. As discussed in the Standard and Poor's article appended to Ms. Omohundro's testimony as PPL Exhibit 101, most of the investor-owned electric utilities located in the WECC have some form of power cost adjustment mechanism at this time with the exception of a few utilities including the Company and Portland General Electric Company. An important factor that should be considered in the Commission's evaluation of our request is the fact that the Company bears more risk than many of the utilities who have such mechanisms because of our greater cost variability arising from our dependence upon hydro resources.

Q. Would Commission adoption of the Transition Adjustment mechanism requested by the Company in Docket UE-170, rebalance net power cost exposure historical levels?

A. No. Adoption of an annual power cost update certainly moves the distribution of the exposure in the right direction because it eliminates a large portion of recovery lag. However, it does not address net power cost exposure between rate cases.

Q. How do you propose to rebalance the asymmetric net power cost exposure that the Company is shouldering?

A. The Commission should adopt the Company's proposed PCAM to rebalance net power cost exposure between customers and the Company so they are closer to historical levels. Failure to do so would likely result in a systemic under recovery of net power costs that are prudently incurred to serve customers and would not consistently provide our customers proper price signals for energy consumption decisions.

Q. Will customers and shareholders both benefit from implementation of the proposed PCAM?

A. Yes. As explained by Ms. Omohundro, a PCAM should enhance the Company's credit quality and lower its cost of borrowing. Moreover, rating agencies treat certain payments associated with purchase power agreements ("PPAs") similar to debt on a balance sheet. The adoption of a PCAM would lower the level of that debt imputation and thus the Company's capital costs, resulting in lower overall rates for customers. A PCAM would also help level the playing field for resource selections when evaluating PPAs compared to building Company owned projects as the debt imputation ascribed PPAs would decrease.

From a shareholder perspective, redistribution of the risk associated with the current asymmetric net power cost exposure between customers and shareholders through a PCAM should allow the Company to recover a higher percentage of its prudently incurred costs. In no event, however, will implementation of the PCAM permit the Company to recover more than its prudently incurred costs due to the proposed sharing bands and earnings test.

Q. Does the level of debt imputation vary by type of PCAM?

A. Yes. For Standard and Poors, a 10-20 percent imputation is applied when the PCAM is legislatively approved, a 30-50 percent imputation is applied for a Commission based PCAM and a 50-70 percent imputation is applied without a PCAM.

PCAM Structure

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

A. The PCAM is an incentive-based mechanism that would share variations in adjusted actual net power costs from the baseline forecast net power costs in rates, with one exception. The one exception is that 100 percent of cost increases or decreases related to Qualifying Facility ("QF") contracts would be exempted from the sharing bands because the purchases are required by PURPA. All other costs would be subject to symmetrical sharing bands, which straddle baseline NPC in rates. When actual adjusted net power costs are within plus or minus $100 million, total Company, the increment would be allocated 70 percent to customers and 30 percent to the Company. When the increments exceed plus or minus $100 million total Company, the increment would be allocated 90 percent to customers and 10 percent to the Company so as to provide catastrophic protection. Mr. Duvall describes the steps necessary to allocate the accruals to Oregon pursuant to the Revised Protocol.

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

A. The baseline forecast will be the net power costs adopted from the Company's annual Transition Adjustment mechanism or rates in effect during the measurement period. The Transition Adjustment mechanism includes an annual update of the Company's net power costs and is a component of the Company's general rate case (UE-170), which is currently being processed by the Commission. Measurement periods should be tied to the balancing account trigger which is discussed later in my testimony.

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

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

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

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

Q. Is the Company proposing a fixed period of time after which the Company may request recovery of or return of accrued balances to customers?

A. No. The Company proposes that a plus or minus $15 million accrued balance be established as a trigger. Once the trigger is reached, the Company will be required to return the balance to, or request recovery from, customers. This approach is more beneficial than setting a fixed period because it should reduce the amount of rate changes during periods of lower net power cost volatility and reduce rate shock during periods of higher volatility when balances could be much higher. It will also provide more current prices signals during periods of higher net power cost volatility. The amortization period should be over a one-year period or such longer period necessary to comply with ORS 757.259.

Q. Is the mechanism designed to take into account all net power cost components?

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

Q. Please explain PPL Exhibit 204.

A. PPL Exhibit 204 is an illustration of how the Company's proposed PCAM would have operated during calendar year 2004, assuming the net power costs authorized in Docket No.UE-147 had been in effect for the entire year. As shown, the total Company net power cost variance from Oregon authorized net power costs would have been $147.6 million. After exclusion of the Company's $34.8 million allocated share, $25.1 was related to Company-owned west hydro, $7.4 million was related to Company-owned east hydro, $.7 million was related to Mid-

Columbia hydro, $4.6 million was related to existing QF contracts and $76.1 million was related to "All Other", which includes fuel prices, market prices, contract changes etc. Oregon's allocated share of these costs would have been $41.7 million.

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

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

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

A. If the Company's actual rate of return shown in the Company's most recent semi-annual report was above authorized levels, costs accrued during that period would not be recoverable. Conversely, if earned rates of return are below authorized levels, accrued balances owed to customers would not be returned.

Q. How will the sur-charges and sur-credits be allocated to customers?

A. Both will be spread to customers on a uniform cents-per-kwh basis to all customer classes in order to reflect changes in costs per MWh incurred by the Company to serve customers. Because differences in delivery voltage result in different line losses and power requirements, the Company proposes to vary the sur-charge and or sur-credit amounts by delivery voltage. The loss factors in effect at the time of the accrual would be used for this determination. The Company's proposed rate schedule for this mechanism has been included as Exhibit A to the Application for this mechanism.

Q. Does this complete your direct testimony?

A. Yes.

Case UM –
PPL Exhibit 201
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer

NPC In Rates Vs Actual

April 2005

PacifiCorp
NPC In Rates Vs Actual
1990-2004
Millions $

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000 (1)	2001 (2)	2002	2003 (3)	2004
NPC in Rates	383.4	383.4	383.4	383.4	383.4	383.4	424.1	453.2	453.2	453.2	573.8	984.0	591.7	648.2	598.0
Actual NPC	393.9	393.5	407.4	372.2	402.4	360.0	400.9	369.9	444.8	431.7	841.1	1210.4	677.7	598.2	745.6
Difference	(10.5)	(10.1)	(24.0)	11.2	(19.0)	23.4	23.2	83.3	8.4	21.5	(267.3)	(226.4)	(86.0)	50.0	(147.6)
Average Difference					10.7 1990-1999								(135.5) 2000-2004		

Notes:

1 NPC in Rates Includes 61 days of 668 million of deferred excess power costs
2 NPC in Rates Includes 252 days of 668 million of deferred excess power costs
3 NPC in Rates includes Includes 56 million of Summer 2002 Purchase Power Deferral

Widmer Exhibit 202

Case UM –
PPL Exhibit 202
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

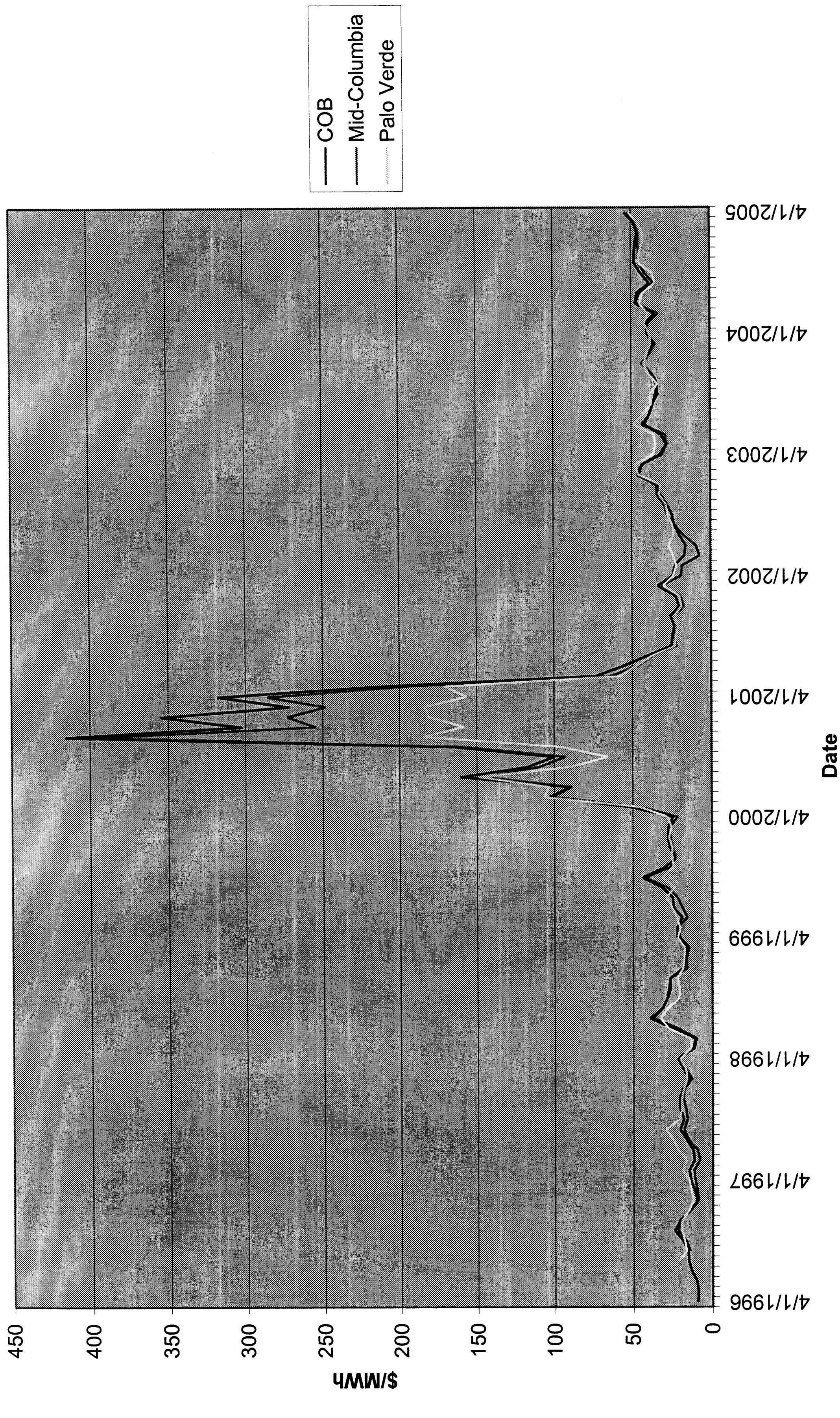
PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer

Historical Average Market Prices

April 2005

Historical Average Market Prices



Case UM –
PPL Exhibit 203
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

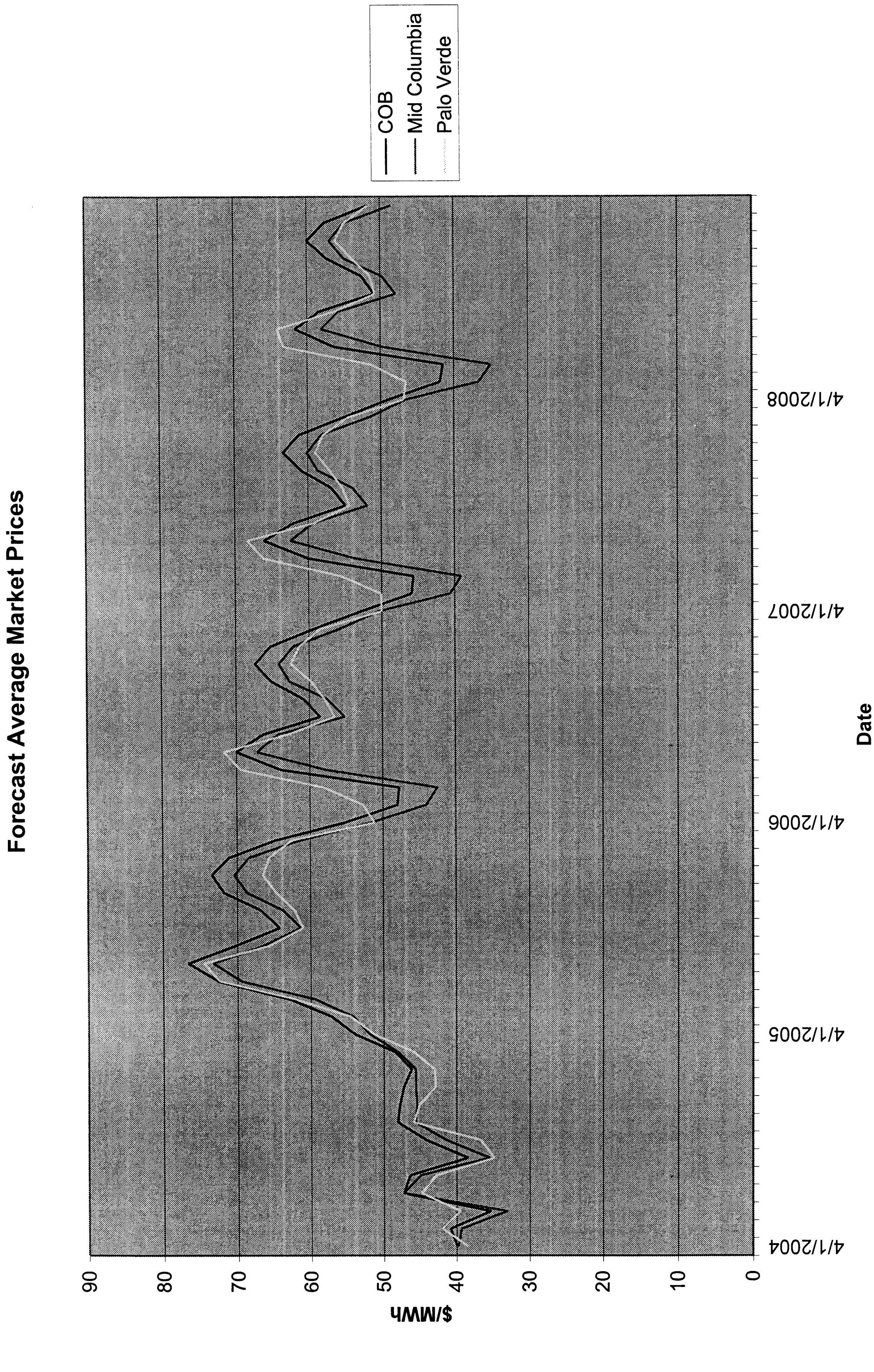
OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer

Forecast Average Market Prices

April 2005


Forecast Average Market Prices
COB
Mid Columbia
Palo Verde
$/MWh
90
80
70
60
50
40
30
20
10
0
4/1/2004
4/1/2005
4/1/2006
4/1/2007
4/1/2008
Date

204 Widmer Exhibit

Case UM –
PPL Exhibit 204
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark T. Widmer

PCAM Scenarios

April 2005

PacifiCorp
PCAM Scenarios
No Deadband, 70% Customer / 30% Shareholder Sharing up $100 Million NPC Change, then 90% Customer / 10% Shareholder Sharing after Oregon's Allocated Share

	Scenarios	FY2004 Actuals
	Total Company Net Power Costs ($)	
1	Actual Net Power Costs	745,626,531
2	Baseline Net Power Costs (NPC in Current Rates)	598,000,000
3	**Total NPC Variance** (line 1 - line 2)	147,626,532
	PCAM GRID Studies	
4	Test Period Normalized Net Power Costs - Market Price Change	581,192,825
5	Test Period Normalized Net Power Costs - Actual Owned Hydro	623,692,264
6	Test Period Normalized Net Power Costs - Actual Mid-C	582,140,329
	Actual Hydro Generation (MWh)	
7	Company owned - West	3,230,154
8	Company owned - East	191,823
9	Mid Columbia	1,816,929
	Normalized Hydro Generation In Rates (MWh)	
10	Company owned - West	4,329,416
11	Company owned - East	515,788
12	Mid Columbia	1,921,759
	Hydro Generation Difference (Actual less Normalized MWh)	
13	Company Owned - West (line 7 - line 10)	(1,099,262)
14	Company Owned - East (line 8 - line 11)	(323,965)
15	Mid Columbia (line 9 - line 12)	(104,830)
	Total Additional NPC Cost / (Benefit) ($)	
16	Company Owned Hydro - West ((line 5 - line 4) X ((line 13 / (line 13 + line 14)	32,825,420
17	Company Owned Hydro - East ((line 5 - line 4) X ((line 14 / (line 13 + line 14)	9,674,019
18	Mid Columbia (line 6 - line 4)	947,505
19	Existing QF	4,606,100
20	New QF	0
21	All Other (line 3 - sum(line16:line20))	99,573,488
22	**Total**	147,626,532

PacifiCorp
PCAM Scenarios
No Deadband, 70% Customer / 30% Shareholder Sharing up $100 Million NPC Change, then 90% Customer / 10% Shareholder Sharing after
Oregon's Allocated Share

	Scenarios			FY2004 Actuals
	Total Company Net Power Costs ($)			
1	Actual Net Power Costs			745,626,531
2	Baseline Net Power Costs (NPC in Current Rates)			598,000,000
3	**Total NPC Variance** (line 1 - line 2)			147,626,532
	Dead Band		$	
23	Net Power Costs Variance Upper Dead Band		$0	598,000,000
24	Net Power Costs Variance Lower Dead Band		$0	598,000,000
25	Net Power Costs Variance in excess of Dead Band			147,626,532
26	Excess NPC Variance % of Total NPC Variance (line 24 / line 3)			100%
27	Tier 1			100,000,000
28	Tier 2			47,626,532
		NPC Variance		
	Customer /Company Sharing Ratio	> 0	< 0	
29	**Tier 1 Up to $100 Million**	($100,000,000)	$100,000,000	
30	Customer Sharing %	70%	70%	70%
31	Company Sharing %	30%	30%	30%
	Tier 2 In Excess of $100 Million			
32	Customer Sharing %	90%	90%	90%
33	Company Sharing %	10%	10%	10%
34	Customer Recovery Tier 1			70,000,000
35	Customer Recovery Tier 2			42,863,879
36	**Customer % of Total Net Power Costs Variance**			**76%**
37	**Shareholder % of Total Net Power Costs Variance**			**24%**
	Customer Share Additional NPC Cost / (Benefit) ($)			
38	Company Owned Hydro - West (line 16 X line 36)			25,095,789
39	Company Owned Hydro - East (line 17 X line 36)			7,396,010
40	Mid Columbia (line 18 X line 36)			724,389
41	Existing QF (line 19 X 100%)			4,606,100
42	New QF (line 20 X 100%)			0
43	All Other (line 21 X line 36)			76,126,221
44	**Total Customer Share**			113,948,509
	Company Share Additional NPC Cost / (Benefit) ($)			
45	**Total Company Share** (line 3 - line 44)			33,678,023
	Oregon Allocated Share ($)	MSP Factor	FY2004 %	
46	Company Owned Hydro - West	DGP	57.7814%	14,500,698
47	Company Owned Hydro - East	SG	28.6356%	2,117,892
48	Mid Columbia	MC	69.7298%	505,115
49	Existing QF	Situs		2,744,415
50	New QF	SG	28.6356%	0
51	All Other	SG	28.6356%	21,799,200
52	**Total Oregon PCAM Adjustment**			41,667,320
53	**Oregon % of Total PCAM Adjustment**			**37%**

Case UM-
PPL Exhibit 300
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Gregory N. Duvall

Allocation Methodology

April 2005

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

A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah, Suite 300, Portland, Oregon, 97232. My present position with PacifiCorp is Managing Director, Planning Major Projects.

Qualifications

Q. Briefly describe your educational and professional background.

A. I received a degree from University of Washington in Mathematics in 1976 and an MBA from University of Portland in 1979. I was employed by Pacific Power in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions, trading, and major projects. From 1997 through 2000, I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. Since my return to Portland, I have been involved in direct access issues in Oregon and have been responsible for directing the analytical effort for the Multi-State Process ("MSP").

Q. Have you previously testified in state regulatory proceedings?

A. Yes. I have testified in California, Idaho, Montana, Oregon, Utah, Washington and Wyoming on net power costs, customer class cost of service, avoided costs and direct access. I also sponsored testimony in the Company's Structural Realignment Proposal ("SRP") and MSP proceedings.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. I will describe the allocation methodology utilized in the Power Cost Adjustment Mechanism ("PCAM") to apportion net power cost variances to the Company's Oregon jurisdiction. In the interest of clarity and consistency, when I use a capitalized term in my testimony, and do not otherwise define it, I intend the term to have the same meaning as provided for in Appendix A to the Revised Protocol ratified by the Commission on [date].

Allocation of PCAM Net Power Cost Variances

Q. From a jurisdictional allocation perspective, what principal did the Company follow in designing the proposed PCAM?

A. The primary principal was to ensure that the inter-jurisdictional cost allocation for the PCAM be consistent with the allocations under the Revised Protocol.

Q. Is the allocation of costs under the proposed PCAM consistent with the Revised Protocol?

A. Yes. Under the Revised Protocol, all costs are allocated consistent with the Company's rolled-in methodology, with four exceptions. The first exception, Seasonal Resources, use monthly-weighted allocation factors, rather than annual allocation factors. While this is a change to the Company's rolled-in methodology, the costs of Seasonal Resources are still allocated on a system-wide basis. The other three exceptions result from the application of the Embedded Cost Differential (ECD) to Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts.

Q. What effect does the ECD have on cost allocation?

A. First, the ECD allocates the costs and benefits of the Hydro-Electric Resources to the former Pacific Power and Light jurisdictions. Second, as compared to rolled-in, the ECD allocates a higher percentage of the costs and benefits of the Mid-Columbia Contracts to Oregon and Washington. Finally, the ECD allocates the costs and benefits of Existing QF Contracts on a situs basis.

Q. How does this affect the proposed PCAM?

A. The proposed PCAM is designed to allocated changes in costs and benefits for these three components in a manner that is consistent with the initial allocation of the costs and benefits under the Revised Protocol.

Q. How is this done?

A. As testified by Mr. Widmer, the GRID model is used to isolate all net power cost changes from the baseline forecast..

Q. How are the net power cost changes associated with Existing QF Contracts determined?

A. The actual costs for Existing QF Contracts in Oregon are compared to the costs included in the GRID study used to set current rates. This amount is the PCAM-related adjustment for Existing QF Contracts.

Q. How is the PCAM-related adjustment for Hydro-Electric Resources allocated among the Company's jurisdictions?

A. This adjustment is allocated using the Divisional Generation Pacific (DGP) factor.

Q. How is the PCAM-related adjustment for the Mid-Columbia Contracts allocated among the Company's jurisdictions?

A. This adjustment is allocated using the Mid-Columbia (MC) factor.

Q. How is the PCAM-related adjustment for Existing QF Contracts allocated among the Company's jurisdictions?

A. This adjustment is assigned on a situs basis.

Q. How is the remaining PCAM adjustment amount determined?

A. The remaining PCAM-related changes in net power costs are determined by taking the difference between the adjusted actual and normalized net power costs less the amounts previously applied to Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts.

Q. How is the PCAM-related adjustment for all other resources allocated among the Company's jurisdictions?

A. The remaining PCAM adjustment is allocated on the System Generation (SG) factor.

Q. Does this conclude your testimony?

A. Yes.