Exhibit No.___(RJF-1T)
Docket Nos. UE-061546/UE-060817
Witness: Randall J. Falkenberg

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY Respondent.	)	**Docket No. UE-061546**
In the Matter of the Petition of PACIFIC POWER & LIGHT COMPANY For an Accounting Order Approving Deferral of Certain Costs Related to the MidAmerican Energy Holdings Company Transition.	)	**Docket No. UE-060817**

DIRECT TESTIMONY OF RANDALL J. FALKENBERG

ON BEHALF OF

PUBLIC COUNSEL AND

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

February 16, 2007

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8343 Roswell Road, Sandy Springs, GA 30350.

Q. BY WHOM ARE YOU EMPLOYED?

A. I am President of RFI Consulting, Inc. ("RFI"). I am appearing in this proceeding as a witness for Public Counsel regarding interstate cost allocation and net power cost issues, and for the Industrial Customers of Northwest Utilities ("ICNU") on these issues and the proposed Power Cost Adjustment Mechanism ("PCAM"). My qualifications are shown in Exhibit No.___(RJF-2).

Q. WHAT KIND OF CONSULTING SERVICES ARE PROVIDED BY RFI?

A. RFI provides consulting services in the electric utility industry. The firm provides expertise in electric restructuring, system planning, load forecasting, financial analysis, cost of service, revenue requirements, rate design, and energy cost recovery issues.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. My testimony addresses PacifiCorp's West Control Area ("WCA") jurisdictional cost allocation model and the GRID study of normalized net power costs for the pro-forma period, April 2006 to March 2007. I identify numerous problems in the WCA and GRID models that overstate the Company's Washington revenue requirement. I also address the proposed PCAM.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend a number of adjustments to the WCA model and to PacifiCorp's test year net power costs, resulting in a reduction to the Company's Washington allocated revenue requirements. Table 1, below, shows the dollar impact and approximate Washington allocation of each of my proposed adjustments. The following is a brief summary of each proposed adjustment.

WCA Allocation Model

1. PacifiCorp's WCA model is flawed because it fails to comply with the Washington Utilities and Transportation Commission ("WUTC" or "Commission") used and useful standard. The model includes resources that are not used and useful to Washington while ignoring resources that are used and useful. Further, the model produces results that are demonstrably unrealistic and unreasonable. For this reason, the model should be substantially modified or simply rejected.

2. The WCA model ignores the fact that the Company has the option to buy and sell power between PacifiCorp's Area of Control West ("PACW") and PacifiCorp's Area of Control East ("PACE") and to arbitrage between trading hubs. Leaving this capability out of the model substantially increases PACW power costs and Washington revenue requirements by the amount shown on Table 1.

3. The WCA model also ignores the fact that energy from former Pacific Power and Light ("PP&L") resources in Wyoming (Johnson and Wyodak) flows into the western control area via Jim Bridger. Consequently, these resources are used and useful to Washington. At a minimum, the WCA model should reflect the direct benefits of this energy flowing to PACW from the Johnson and Wyodak resources in the WCA model. This (Part 1 Adjustment) reduces Washington revenue requirements by the amount shown on Table 1.

4. In addition, the WCA model should be expanded to include all former PP&L (eastern Wyoming) loads and resources in the WCA model. This (Part 2 Adjustment) reduces Washington revenue requirements by the amount shown on Table 1.

5. PacifiCorp proposes to use a Control Area Energy West allocation factor ("CAEW") for jurisdictional allocation of production and transmission demand related costs in the WCA methodology rather than the traditional Control Area Generation West ("CAGW") factor. The Company has used the CAGW type of demand allocation factor for all other jurisdictions and in previous Washington cases. PacifiCorp provides no cost justification for the change to the CAEW. It appears this change was simply an opportunistic attempt to increase Washington revenue requirements. Use of PacifiCorp's traditional type of CAGW factor in the WCA model reduces Washington revenue requirements in the amount shown on Table 1.

6. PacifiCorp uses loss factors that overstate energy losses for Washington as compared to other WCA states. This problem overstates the fixed costs allocated to Washington, as well as the total WCA production costs. More realistic loss factor assumptions (based on five years of actual data) results in a reduction to revenue requirements in the amount shown on Table 1.

Net Power Cost (GRID Adjustments)

Short-Term Firm Transaction Adjustments

1. The short-term firm transactions modeled in GRID show a disproportionate number of below-market sales. The Company has not demonstrated these transactions are prudent or necessary to provide service to Washington, and they fail the Commission's used and useful test. Removal of these transactions results in a reduction to net power costs in the amount shown on Table 1.

Long-Term Contract Adjustments

2. PacifiCorp imputes a price to the Sacramento Municipal Utility District ("SMUD") contract of $37/megawatthour ("MWh") based on a previous Southern California Edison ("SCE") contract price. This treatment was first used by the Utah Public Service Commission ("UPSC") because it found the SCE contract to be a prudent, contemporaneous contract that established a benchmark price for SMUD. Because the SCE contract has expired it is no longer an appropriate benchmark and the WUTC should develop its own policies regarding this contract. I recommend the SMUD contract be removed from GRID, reducing power costs by the amount shown on Table 1.

3. PacifiCorp failed to replace all of the capacity of the Centralia plant when the resource was sold. The TransAlta contract replaces only 74% of the plant's energy. Because the Company retained 50% of the gain on the Centralia sale, it should assume 50% of the risk associated with its failure to replace all of the associated capacity and energy. This adjustment reduces net power costs by the amount shown on Table 1

4. PacifiCorp overstates the likely generation from the Georgia-Pacific ("GP") Camas cogeneration facility compared to recent actual data and current trends. Correcting this problem reduces net power costs as shown on Table 1.

Modeling Adjustments

5. PacifiCorp's Vista modeling of 40 water years of data should be modified to exclude water years resulting in power costs that are more than one standard deviation from the mean. This treatment was proposed by the WUTC Staff in Docket No. UE-032065 and accepted by the Company and Commission in

that case. This adjustment reduces net power costs by the amount shown on Table 1.

6. I recommend the Commission reverse the adjustments proposed by the Company related to ramping, and the use of monthly outage rates. These adjustments are not industry standard practices and are not well supported. Reversing these assumptions reduces net power costs by the amount shown on Table 1.

7. The Company proposes to increase its maximum PACW regulating margin from 125 MW to 225 MW. This change in assumptions is unsupported and unrealistic. Reversing this assumption change reduces net power costs as shown on Table 1.

Table 1 quantifies the impact on net power costs associated with implementing each of my proposed adjustments.

Table 1
Summary of Recommended Adjustments
$1000

		Total PACW	Washington Jurisdiction CAEW 22.5244%
I. Jurisdictional Allocation Issues			
WCA Model Corrections		N/A	-$23,482,877
1	Interconnection Benefits	N/A	-$8,567,749
2	Johnson/Wyodak Part 1 (Actual Flow)	N/A	-$3,842,443
3	Johnson Wyodak Part 2 (Include E WY)	N/A	-$8,243,613
4	CAGW Allocation Factor	N/A	-$2,192,439
5	Historical Loss Factors	N/A	-$636,633
II. GRID (Net Power Cost Issues)			
A. Short-Term Firm Adjustments		-$35,235,790	-$7,936,636
6	Remove Short-term firm	-$35,235,790	-$7,936,636
B. Long Term Contract Adjustments		-$20,361,095	-$4,586,206
7	SMUD Contract	-$12,299,225	-$2,770,322
8	TransAlta/Centralia Risk Sharing	-$7,924,453	-$1,784,932
9	GP Camus	-$137,417	-$30,952
B. Modeling Issues		-$10,003,260	-$2,253,170
10	Hydro Water Year Modeling	-6,313,925	-$1,422,171
11	Monthly Outages	-2,521,331	-$567,914
12	Ramping	-$322,172	-$72,567
13	Regulating Margin Modeling	-$845,832	-$190,518
Total Power Cost Adjustments -		-$65,600,145	-$14,776,013
PacifiCorp GRID Request		$417,037,230	$93,934,968
Adjusted GRID Result		$351,437,085	$79,158,955
Total Adjustments		N/A	-$38,258,890

Q. HOW IS THE REMAINDER OF THIS TESTIMONY ORGANIZED?

A. In Section II, I address the jurisdictional allocation (WCA model) issues. In Section III, I address net power cost (GRID model) issues. In Section IV, I am testifying on behalf of only ICNU and I address PacifiCorp's proposed PCAM.

II. JURISDICTIONAL ALLOCATION ISSUE

WCA Allocation Model

Q. WHAT IS THE PURPOSE OF THE WCA ALLOCATION MODEL?

A. The WCA model is PacifiCorp's latest version of a jurisdictional allocation methodology for Washington. Unlike previous iterations, this model will be applicable only to Washington as other states have adopted the Revised Protocol methodology, albeit with various modifications unique to each state.[1/]

Since the merger between PP&L and Utah Power and Light ("UP&L") in 1989, regulators have struggled to find an equitable means of allocating the costs between the six states in which PacifiCorp operates. A jurisdictional allocation methodology is needed to allocate both the fixed and variable production costs of the PacifiCorp system to each of the states.

There are really two elements to this problem: the disparity in costs between the former PP&L and UP&L systems, and Washington's statutory "used and useful" requirement. The lack of a solution can be traced back to decisions made by PP&L and UP&L at the time of the merger. The applicants were anxious to gain approval of the merger and did not resolve this difficult issue when approval of the merger was being sought. Rather, the Company offered to convene a jurisdictional allocation committee with all of the involved states only *after* approval of the merger was obtained.[2/] As a result, there have been a series of processes among the various states designed to address the issue, but even

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1/ The Revised Protocol may be only a shortlived solution in the states that have adopted versions of it. PacifiCorp has already considered proposing significant changes to the Revised Protocol to address what the Company calls divergent state energy policies related to new resource acquisitions.

2/ Re PP&L, WUTC Docket No. U-87-1338-AT, Second Supp. Order at 13 (July 15, 1988).

today, I do not believe there has ever been a true and permanent "meeting of the minds" between the various states, and most certainly there has been no agreement between the WUTC and the Company.

Q. DISCUSS THE FIRST PROBLEM RELATED TO THE DISPARITY IN COSTS BETWEEN PP&L AND UP&L.

A. The WUTC has been quite concerned about the potential problems stemming from this combination since the first order approving the merger:

> Staff witness Folsom correctly points out the discrepancy in average system cost between PP&L and UP&L. The Commission continues to be concerned about the effects on Pacific's ratepayers of merging with a higher cost system, and believes that any integration of the power supply function for the two companies should be done in a manner consistent with Pacific's least-cost planning process, now getting under way. In the meantime, the Commission views Pacific's current average system costs as the appropriate basis for rates.[3/]

From the above, it is well established that the differences in the predecessor system costs was a concern of the WUTC from the start. While western parties traditionally sought to retain the benefits of their lower cost predecessor resources (particularly hydro and low-cost coal), the eastern parties sought to "roll-in" all costs to a simple system average. While versions of the Revised Protocol method is the current compromise on these issues adopted by other states, Washington was unable to adopt this framework owing to its "used and useful" standard.

Q. PLEASE EXPLAIN.

A. In Docket No. UE-050684, PacifiCorp proposed the Revised Protocol methodology for Washington. However, the WUTC rejected the Company filing

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[3/] Id. at 14.

on the basis that it did not establish what resources were "used and useful" in providing service to the state:

> PacifiCorp has failed to meet its burden of proof to show that the resources included in the Revised Protocol inter-jurisdictional cost allocation methodology provide tangible direct or indirect benefits to Washington ratepayers and are "used and useful for service in this state." *See RCW 80.04.250*.[4/]

Because the Revised Protocol method included all of the resources on the system, and the Company failed to establish which of those resources were used and useful in serving Washington, the WUTC rejected the Company's proposed 2005 rate increase.

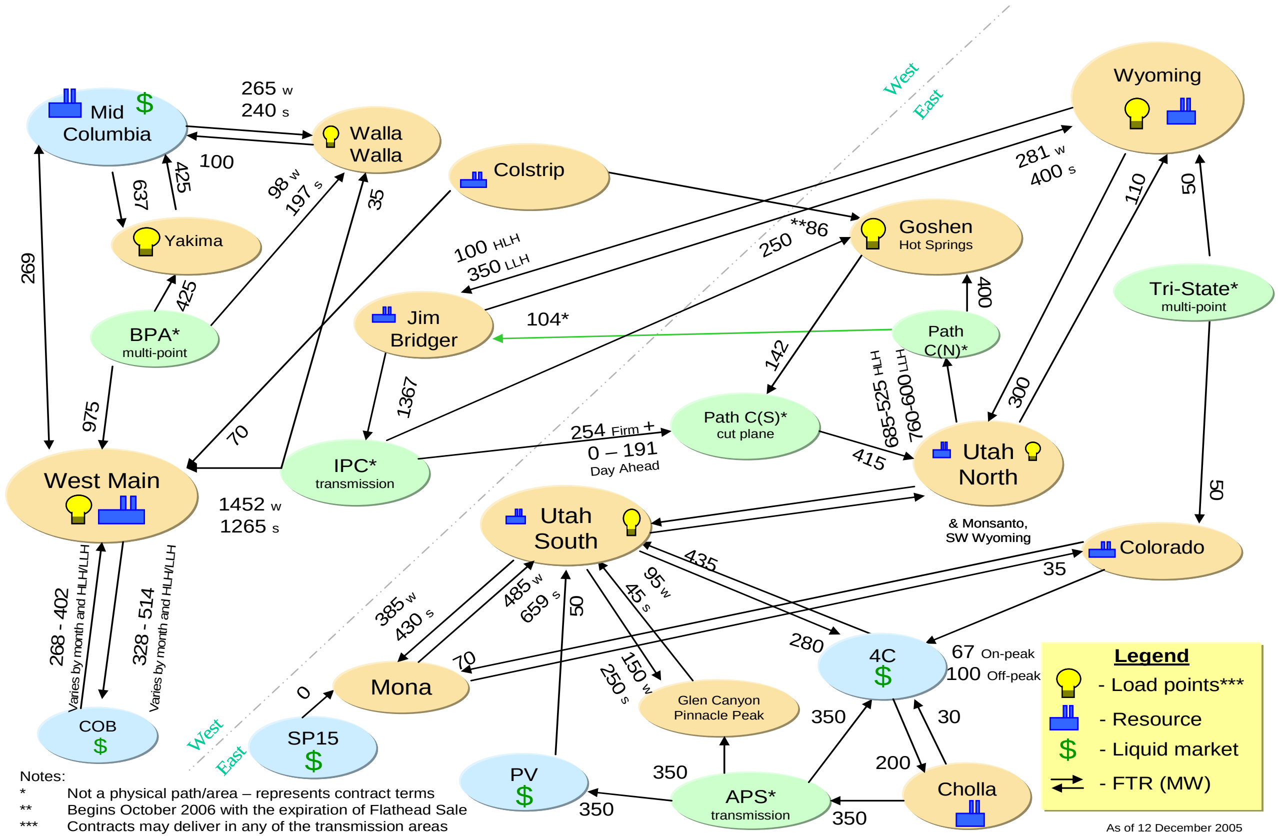
It is against this backdrop that the Company developed its new WCA model. The Company contends that this approach addresses the used and useful standard by including only the costs of those resources located in the Company's WCA.

Q. WHAT IS THE WCA?

A. Please see the figure below. This is a copy of the PacifiCorp transmission topology map used in the Company's GRID model.[5/] This map breaks the system down into PACE and PACW. Each control area contains a specific amount of generation and load and is dispatched more or less independently of the other, though there are some important benefits of integration. Washington is included in PACW, or the WCA.

4/ WUTC v. PacifiCorp, WUTC Docket No. UE-050684, Order No. 04 at ¶ 342 (Apr. 17, 2006).

5/ Algorithm Guide GRID-U020-02-02 Draft v6.1.a, page 55



Q. DESCRIBE THE MAJOR ELEMENTS OF THE WCA MODEL.

A. The WCA model includes only the PACW resources. This would limit the thermal resources to the Bridger and Colstrip coal plants, Hermiston, and the PACW hydro. There are also various contracts and liquid trading hubs contained in PACW as well.

The model includes both the fixed (return on investment, taxes, depreciation, etc.) and variable costs of power production for PACW. A special version of the GRID model provides the dispatch, and production simulation used to determine variable costs. While the model includes the cost for all of the transmission lines and contracts included in PACW, the Company assumes that there is no physical or contractual interconnection with PACE. The Company completely ignores the fact that PACW resources provide benefits to the integrated system, and would have opportunities to make profitable energy sales in eastern markets. This is a significant omission that will be discussed in depth later. Effectively, the WCA model assumes the "world ends" at the interconnection between PACW and PACE. While PacifiCorp has insisted for years that it operates a fully integrated system, the Company now tries to "unscramble the egg" within the WCA model, and treat PACW as a stand alone system. In so doing, it grossly exaggerates the cost of serving PACW.

Q. IS THIS "STAND ALONE" PACW SYSTEM REQUIRED BY THE COMMISSION'S ORDER FROM DOCKET NO. UE-050684?

A. No. Nothing in the Commission's order requires or even suggests that only PACW resources should be included in Washington's cost structure. Instead, the Commission articulated a "used and useful" standard that is the key determinant of which resources should be considered. The Company provides regulatory simplicity (by selectively modeling only a part of the system's resources) while ignoring the Commission's longstanding requirement that the combination of the high cost UP&L system with the much lower cost PP&L system should not harm Washington ratepayers. I will show that the method completely fails to address the Commission's used and useful standard.

Q. DOES THE WCA MODEL PROVIDE A REASONABLE AND REALISTIC METHODOLOGY?

A. No. The model is too simplistic and ignores many elements that exist in the real world. For this reason, it substantially overstates costs for PACW, as I will now demonstrate. Despite these significant problems, the WCA may provide a starting point within which to develop an appropriate cost allocation methodology because it assumes that the eastern resources are not used and useful in Washington.

WCA Model: PACW vs. PACE and GRID vs. Actual Cost

Q. ELABORATE ON YOUR POINT REGARDING THE DISPARITY IN COSTS BETWEEN PACW AND PACE IN THE WCA MODEL.

A. Exhibit No.___(RJF-3) compares the net variable power costs of PACW and PACE based on the WCA GRID model, and one of the most recent GRID studies performed by the Company in Oregon. Intuitively one would expect that the west would have *lower* power costs than the east, owing to the preponderance of low-cost hydro and coal-fired generation, coupled with the lowest cost gas-fired generation on the system. However, in the WCA model just the opposite occurs. In the WCA model, PACW has an average cost of $20.6/MWh compared to $12.7/MWh for the east.

Some of the cost differences between PACE and PACW can be explained. For example, the Company asserts that transmission costs for PACW are higher than PACE because PACW relies more on contractual paths, rather than ownership of assets. Further, there are gas resale revenues associated with PACE resources, but not PACW resources. Finally, the Oregon GRID model included certain credits for a settlement in the most recent rate case (UE 179). Even after adjusting for all of these known differences, the WCA GRID model still shows power costs almost 30% higher than the Oregon GRID model implies for PACE.

These are unreasonable results, and certainly ones that fly in the face of the longstanding expectation that, by virtue of its much lower cost resources, PACW should enjoy lower variable power costs than PACE. The fact that the WCA model produces this anomalous result leads one to question its veracity from the very start. I find it hard to believe that the Commission would wish to support a method that results in power costs some 62% higher for customers in Washington than those in the eastern states. Certainly, there has never been any evidence to support the notion that PACW, rather than PACE, was the "high cost" system. This certainly runs counter to the general tone of the discussion in the recently completed Multi-State Process ("MSP"), to say the least. In the end, I suspect that the WCA GRID model has been contrived by the Company to produce these spurious results. I will demonstrate later many ways in which the model has been manipulated to produce unrealistic results.

Q. HAVE YOU DEVELOPED A COMPARISON OF THE WCA GRID MODEL TO PACIFICORP'S ACTUAL NET POWER COSTS?

A. Yes. While PacifiCorp contends that it has not developed any analysis of actual PACW costs, I have developed a reasonable approximation of actual PACW costs from the Company's monthly power cost reports. Exhibit No.___(RJF-4) compares the normalized actual PACW net variable power costs to the WCA GRID model results. The actual results were developed from the response to ICNU data request ("DR") No. 1.27.[6/] This analysis compares the actual costs for the PACW resources included in the WCA GRID model. Because the PACW resources provide more generation than required to serve PACW load, load and supply were balanced using PacifiCorp's projected average price for short-term purchases. Because GRID balances load and supply at these (input) prices it

[6/] See Exh. No.___(RJF-12) at 6.

provides for a better comparison if the GRID prices are used. However, my analysis indicates the results would not change significantly, if actual short-term transactions prices were used instead. To make the results comparable to the GRID results, I also used the projected test year loads and hydro generation, GRID transmission costs, and re-priced the SMUD sale at $37/MWh, the price used in the GRID model by the Company.[7/] These results can be thought of as "normalized actual costs" and are comparable to the figures used in GRID.

The exhibit compares the GRID model results for varying time periods including the 2006 fiscal year, the 12 months ended October 2006, and the most recent 12-month period (December 2005 to November 2006). The results show that the GRID model consistently overstates power costs for the WCA by $50 million or more compared to normalized actual costs. This illustrates that the proposed WCA model is unrealistic from the very start and not suitable for use by the Commission at this time. Exhibits No.___(RJF-3) and No.___(RJF-4) clearly illustrate that the Company's proposed net variable power cost model for PACW is simply not credible as it implies substantially higher normalized costs for PACW than PACE, as well as much higher costs than actual.

Used and Useful Standard

Q. DOES THE WCA MODEL COMPLY WITH THE COMMISSION'S USED AND USEFUL STANDARD?

A. No. The Company assumes (in the absence of any proof) that nearly *all* PACW resources are *a priori* used and useful to Washington, and are the *only* resources on its system used and useful for Washington. Neither assumption is true.

7/ This will be discussed shortly.

In its Final Order in Docket No. UE-050684, the Commission never once stated that it required the Company to produce a model whose costs were limited to PACW resources. Rather, the Commission stated in numerous places that it required resources "used and useful" to Washington be included in the model.

Q. REVIEW THE COMMISSION'S USED AND USEFUL STANDARD.

A. The Commission defined used and useful resources as those resources that were useful in providing service to the state:

> In determining whether public utility property is "used and useful for service in this state," the Commission considers whether a resource provides benefits to ratepayers in Washington either directly (e.g., the flow of power from a resource to customers) and/or indirectly (e.g., reduction of costs to Washington customers through exchange contracts or other quantifiable tangible or intangible benefits), commensurate with its cost.[8/]

PacifiCorp simply ignored this direction from the Commission, and in so doing overlooked significant resources that benefit the west. In the end, the greatest problem is that the Company has failed to reflect *all* of the resources that are used and useful to Washington, while including other resources that are *not* used and useful to Washington. I will discuss this problem later in my testimony concerning net power costs.

Q. SUMMARIZE YOUR VIEWS ON THE WCA MODEL?

A. The model fails to address the Commission's longstanding concerns, and the requirements stated in its order in Docket No. UE-050684. It is a shallow attempt to court favor with the Commission by trading simplicity for higher cost to customers. I recommend the Commission either substantially modify the model or reject it out of hand, as it did with the Revised Protocol model in Docket No.

[8/] WUTC Docket No. UE-050684, Order No. 04 at ¶ 340.

UE-050684. In that case, the Commission wisely chose to reject the Company's argument claiming it had an entitlement to use of a flawed jurisdictional model. The Commission should not abandon its position in this case simply because the Company has created the appearance of a more compliant model. As explained by the Commission:

> The Company claims that it is entitled to full recovery of its prudently incurred costs systemwide and should not bear the risk that state decisions about cost recovery will not, in combination, ensure this entitlement. The Company points to no provision of law in support of this proposition. In fact, the Company created and accepted the risk that divergent allocation decisions among the states might result in under-recovery when it chose to merge 20 years ago. Our order approving that merger read together with the merger order of the Oregon Commission make clear that this risk existed, that the Company was aware of it, and that the Company accepted that it alone would bear the risk:
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> > Pacific agrees, however, that its shareholders will assume all risks that may result from less than full system cost recovery if interdivisional allocation methods differ among the merged company's jurisdictions.
>
> Further, the Company admits in the Revised Protocol that it bears the risk of inconsistent allocation methods adopted by the states. In short, any claim of entitlement to a uniform allocation methodology among the states is inconsistent with the "deal" the Company agreed to in the merger.[9/]

As in Docket No. UE-050684, the Commission could reject the Company filing, and refuse to grant the requested rate increase. However, for reasons that will be discussed shortly, this may actually be an overly generous treatment for the Company because even the most obvious corrections to the WCA and GRID models support a reduction in rates for the Company.

[9/] Id. at ¶ 56 (internal footnotes omitted).

Corrections to the WCA Model

Q. ASSUMING THE COMMISSION DESIRES TO CORRECT, RATHER THAN REJECT THE WCA MODEL, WHAT CORRECTIONS DO YOU RECOMMEND?

A. The most fundamental problem with the WCA model is that it is too simplistic in assuming that PACW resources would have no connection to the eastern side of the system and that only PACW resources are used and useful for Washington. It ignores the Commission's fundamental test for whether a resource is used and useful. That test is stated in terms of a cost-benefit analysis:

> The Company's reliance on this citation is misplaced and overlooks the Commission's fundamental premise—*facilities must serve and be found to provide quantifiable benefits before costs can be allocated to ratepayers.* Recognizing the need for allocation is not the same as determining *how* the allocation should be made.[10/]
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> * * *
>
> We find, however, that the Company must demonstrate tangible and quantifiable benefits to Washington of resources in the system before we will include the resources in rates. *The test for including a resource in rates is not whether it is "needed, deliverable and least cost" but rather whether it provides quantifiable direct or indirect benefits to Washington commensurate with its cost.*[11/]

In developing its WCA model based solely on PACW resources without interconnections, the Company has completely ignored every aspect of these tests. The Company has not produced any evidence that the resources it includes provide direct or indirect benefits to Washington commensurate with cost. Nor has the Company performed any test of resources outside of PACW to see if they provide benefits that are commensurate with cost. As a result, the Company has

10/ Id. at ¶ 58 (emphasis added).

11/ Id. at ¶ 68 (internal footnotes omitted, emphasis added).

skewed the model against Washington ratepayers by ignoring some of the most obvious resource choices, specifically the PACW-PACE interconnection and the Dave Johnson and Wyodak coal plants. These facilities should be reflected in the WCA model. I will discuss both of these topics next.

<u>Benefits of Interconnections</u>

Q. ARE PACW AND PACE INTERCONNECTED?

A. Yes. The Transmission Topology Map shown above demonstrates that the two systems are interconnected, and are fully capable of moving power across the system. In the normal operation of the system, PACW provides benefits to the east by providing low-cost energy, and provides operating reserve ("dynamic overlay") benefits. This reduces the overall cost of system operation. In prior cases, the Company estimated the benefits of system integration to be more than $200-300 million NPV for the period 2005 to 2018.[12/] Under the proposed WCA model, all of the benefits of system integration would inure to the states that have adopted the Revised Protocol methodology, and Washington would receive none of these benefits. This is hardly an equitable allocation of benefits, considering Washington will be assigned costs of various resources (generating units and transmission costs) that enable these benefits to be produced. The proposed WCA model is also inconsistent with how PacifiCorp built and actually operates its system.

[12/] <u>Re PacifiCorp</u>, Oregon Public Utility Commission ("OPUC") Docket No. UM 1050, Exhibit ICNU/200 at 7 (Aug. 6, 2004).

Q. IS THIS A REASONABLE TREATMENT?

A. No. The system operates in a manner that minimizes total cost. Even if there was no joint ownership of the PACW and PACE resources, the interconnections would still exist. Indeed, the Company has included all of the costs of PACW transmission equipment and contracts in the WCA model. If the transmission costs are included, the opportunity to use those assets for the maximum benefit of the customers should also be considered. Unfortunately, in the WCA model, the Company includes only the costs, while ignoring some of the most important benefits of the PACW–PACE interconnections. This is an extremely odd treatment in the model considering how the Company modeled the California-Oregon-Border ("COB") interconnection.

Q. PLEASE EXPLAIN.

A. In the WCA model, the Company recognizes COB as a liquid trading hub. Thus, the costs of the interconnection are included, and the model buys and sells power as appropriate to minimize cost. However, when it comes to the PACE interconnection, the Company completely ignores that it exists at all. It makes no sense to include COB, while ignoring PACE as a potential market for surplus PACW generation. Yet this is exactly what the Company has done in the WCA model.

Q. DISCUSS THE PATHS USED TO DELIVER POWER FROM PACW TO PACE.

A. As shown on the transmission topology map above, power may flow from PACW to PACE by a variety of routes. For example, it could flow from Bridger to IPC to Utah North, or from Bridger to Wyoming to Utah, or from Colstrip to Goshen to Utah. These routes provide the opportunity for generation surplus to PACW needs to be sold in PACE. There would also be the opportunity for arbitrage between western markets (e.g., Mid-Columbia ("Mid-C") or COB) and the eastern market hubs (Palo Verde, SP15, and 4 Corners.)

Q. EXPLAIN HOW THIS ARBITRAGE MIGHT WORK.

A. In a situation where Mid-C has a lower market price than Palo Verde, for example, the Company might purchase low cost generation from Mid-C, and, allow some of it to be delivered to the east rather than delivering power from Bridger to the west. In the east, generation that might have been used to serve Utah loads, could then be used to sell into the Palo Verde market. While specific transactions may or may not operate in precisely this manner, the Company has at least five major market hubs, and can use the limited transmission and its generation resources to perform a wide variety of transactions.[13/]

Q. WOULD IT ACTUALLY BE NECESSARY TO ASSUME PACW POWER WAS ACTUALLY SOLD DIRECTLY TO THE PACE MARKET HUBS?

A. No. Power could simply be delivered from PACW to PACE. Because the three hubs interconnected with PACE (Palo Verde, 4 Corners and SP 15) are all liquid markets, they would influence (if not set) the market price for deliveries to PACE. If the GRID model was set to allow PACW to sell power to PACE, similar to the way PACW sells to COB, the GRID model could allow PACW to make sales at a

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13/ Such transactions fit directly into the Commission's used and useful requirement that considers whether a resource provides benefits to ratepayers in Washington either directly (e.g., the flow of power from a resource to customers) and/or indirectly (e.g., reduction of costs to Washington customers through exchange contracts or other quantifiable tangible or intangible benefits), commensurate with its cost.

price comparable to the prices at the Palo Verde, SP 15 and 4 Corners hubs, subject to applicable transmission constraints.

Q. DOES THE COMPANY NORMALLY MODEL SUCH OPPORTUNITIES IN ITS FULL (PACW+PACE) GRID MODEL?

A. Yes. In the recently completed Oregon general rate case, Mr. Widmer testified as follows:

> Consistent with normalized ratemaking these values are captured on a deterministic basis by GRID. The system dispatch portion of the model is a linear program that optimizes the company's system based upon market prices, load requirements, resource characteristics, transmission availability including monetization of available transmission by buying energy in a lower priced market hub and reselling the energy in higher priced market hub and curtailing generation when lower cost market purchases are available.[14/]

Q. DOES THIS OMISSION HAVE A SUBSTANTIAL IMPACT ON THE COST OF POWER IN THE WCA MODEL?

A. Yes. Based on the data contained in the WCA model, market prices in PACE exceed those in PACW thousands of hours during the test year. In such situations, the opportunity would exist for the Company to sell a limited amount of surplus PACW generation to PACE. Though it happens less frequently, in some cases, prices in PACE are lower than PACW prices. In such case, the Company could purchase in the east and offset purchases in the west.

Q. ARE THERE ANY OTHER IMPLICATIONS OF THIS?

A. Yes. The Company excluded some of the Jim Bridger capacity in the WCA model because a fraction of the Bridger generation is delivered to PACE. As a result, the Company excludes 5% of the Bridger capacity from the model. This, however, is not a reasonable basis for excluding Bridger's cost and generation.

[14/] Re PacifiCorp, OPUC Docket No. UE 179, Exhibit PPL/506 at 5 (Widmer Rebuttal).

As shown above, Bridger could deliver power to PACE, and it may be doing so, simply to provide generation to that market when prices make such a transaction favorable. It does not imply that 5% of Bridger's capacity should be ignored completely and assigned to the east. Rather, this is just another example of a benefit of PACW resources not considered in the WCA model.

Q. HAVE YOU QUANTIFIED THE IMPACT OF EXCLUDING THE INTERCONNECTION BENEFITS FROM THE WCA MODEL?

A. Yes. In Exhibit No.___(RJF-5) I present an analysis of the bias built into the WCA model because it ignores the actual interconnections to PACE. This was computed in two parts. First, I included the benefit of transactions not modeled in the WCA GRID model that should have been included. Second, I reflect the value of the reserve capacity PACW provides PACE for purposes of regulating margin and quick start reserves. This approach is rather conservative because it ignores more than $1 million in direct benefits that would result from full inclusion of 100% of the Jim Bridger capacity in the WCA model.

Q. HOW DID YOU ESTIMATE THE BENEFITS OF THE PACW-PACE TRANSACTIONS EXCLUDED BY THE COMPANY?

A. I compared the market price curves for Mid-C, to Palo Verde, SP15 and 4 Corners. When western prices were lower than eastern prices, and the Company had generation to sell I modeled a sale transaction between west and east. Because GRID already included the benefits of making such sales in the west, I reflected only the added margin from the sale. I limited such sales to the transfer capacities (to 415 MW based on Path C to Utah) shown on the transmission topology figure above. In other words, I limited my adjustments based on the real world operational constraints of PacifiCorp's system.

In situations where PACE market prices were lower than PACW prices, I modeled purchases. In this case, however, purchase transactions were limited to only 104 MW, as shown on the transmission topology map above.

This analysis identified potential savings for PACW customers from such transactions of $5.7 million. This result is quite reasonable because the amount of generation flowing from west to east in my model was less than the amount shown by the Company in its recent GRID studies filed in Oregon as part of UE 179. It is important to make clear that in calculating my estimate of the benefits associated with system integration, I focused on the only actual transmission capabilities between the PACW and PACE.

For the dynamic overlay benefits I used estimates derived by the Company as part of its MSP process.[15/]

Wyodak and Johnson

Q. WAS THE FAILURE TO MODEL THE PACW-PACE INTERCONNECTIONS THE ONLY PROBLEM IN THE WCA MODEL?

A. No. The Company also ignored the fact that the Wyoming resources, Dave Johnson and Wyodak are used and useful for Washington.

Q. EXPLAIN WHY JOHNSON AND WYODAK ARE USED AND USEFUL.

A. These resources are obvious possibilities that the Company should have included. First, Johnson and Wyodak were part of the pre-merger PP&L system, and as such, have had their costs included in Washington ratebase ever since they were

15/ WUTC Docket No. UE-032065, Exh. No. 406C at 35-41 (PacifiCorp's Response to OPUC Staff DR No. 61 in OPUC Docket No. UM 1050).

first installed. To my knowledge there has never been any order issued by the WUTC specifically questioning whether these plants were used and useful. As noted earlier, the Commission's starting point in analysis of the cost structure for Washington has always been the costs of the pre-merger PP&L system. Excluding these resources from Washington requires substantial justification by the Company.

Second, in all of the most recent Washington rate cases (UE-991832, UE-032065, and UE-050684), the Company included these plants in ratebase and sought recovery from retail consumers for their costs. There is no basis for assuming that these facilities have not been included in Washington rates, or that they were ever viewed as being anything but "used and useful."

Third, power from these resources is being delivered to PACW, based on PacifiCorp's various GRID studies, as filed in prior cases in Washington and Oregon. I will elaborate on this point later. Even though the Commission does not solely base its used and useful determination on the deliverability of power, this is a pertinent point.[16/] Exhibit No.___(RJF-6) shows results of PacifiCorp's GRID study developed for Docket UE-050684, illustrating that power from Wyoming (Johnson and Wyodak) is indeed being delivered to Bridger, which is located in PACW. This power in turn can be delivered from Bridger to any point in the west, including Washington.

16/ Indeed, as discussed earlier, the Commission considers whether a resource provides benefits to ratepayers in Washington either directly (e.g., the flow of power from a resource to customers) and/or indirectly (e.g., reduction of costs to Washington customers through exchange contracts or other quantifiable tangible or intangible benefits), commensurate with its cost.

Finally, these resources pass the Commission's cost benefit test in that they directly or indirectly provide benefits to Washington and their costs are more than commensurate with the benefits provided. Indeed, the Johnson and Wyodak plants are among the lowest cost resources on the system, and it appears the Company simply excluded these facilities to penalize Washington for not accepting the Revised Protocol method. I recommend a two-part adjustment designed to deal with this problem.

Q. PLEASE EXPLAIN PART 1.

A. Exhibit No.___(RJF-7) shows my calculations. The first part of my proposed adjustment would simply include the benefits of the energy already being delivered from Johnson and Wyodak to Jim Bridger in the WCA model. This is the minimum adjustment the Commission should consider. This amounts to approximately 97 MW during the light load hours ("LLH"). Because this capacity is not available during on-peak hours, the associated fixed costs should not be included in the capacity cost component of the WCA. Including the Johnson and Wyodak generation during LLH would reduce PACW power costs by $3.8 million, as shown in Exhibit No.___(RJF-7) and Table 1.

Q. EXPLAIN PART 2 OF YOUR ADJUSTMENT.

A. By ignoring the pre-merger PP&L system, and instead limiting resources included in the WCA model to PACW resources, the Company excluded these two very low-cost plants. Overall, these plants average cost per kWh produced is approximately $21/MWh. This is nearly the same as the average cost of the Colstrip and Bridger plants, which the Company included in the WCA model.

Owing to their low cost, previous history of inclusion in rates, and deliverability of power, there is no reason not to believe that the Wyodak and Johnson units are used and useful for Washington.

However, if the pre-merger PP&L Wyoming plants are included in the WCA model, then so should the eastern Wyoming (former PP&L) loads served by these plants. Once the Wyoming loads are included, the average variable power costs for the former PP&L system is reduced by $2.65/MWh from the level the Company computed for PACW. Washington's share of these savings (over and above the savings in Part 1) is $8.2 million, and is shown on Table 1.

Q. DO YOU NEED TO MAKE ANY ADJUSTMENTS TO THE FIXED COST COMPONENTS OF THE WCA MODEL TO REFLECT THE INCLUSION OF THESE TWO PLANTS?

A. Ideally, one would. However, the average fixed cost per kWh for Johnson and Wyodak is quite close to the level already built into the WCA for Bridger and Colstrip, and is substantially lower than the average embedded cost for all PACW resources.[17/] As a result, it is likely that including the fixed costs in a more encompassing model would further reduce the average cost for WCA resources, producing a larger adjustment.

Q. CAN ALL OF THE POWER GENERATED BY THE WYOMING UNITS BE DELIVERED TO PACW?

A. No. Transmission constraints limit deliverability (see the Transmission Topology Map), although as shown in Exhibit No.___(RJF-6), substantial amounts of power from Johnson and Wyodak are delivered to PACW. However, as discussed above, the Commission does not rely solely on deliverability in its used and useful

[17/] I estimate this to be in excess of $40/MWh.

test. By averaging in the eastern Wyoming loads and resources, the issue of deliverability is not a problem.

<u>Other PACE Resources</u>

Q. HAVE YOU CONSIDERED INCLUSION OF OTHER PACE RESOURCES IN THE JURISIDICTIONAL MODEL?

A. Yes. In my testimony in Docket No. UE-050684, I analyzed the deliverability of power from other PACE resources. The results showed that other PACE resources were very unlikely to deliver any significant amount of power to PACW. Similar GRID runs from recent cases appear to confirm this conclusion. Therefore, I do not propose that other PACE resources be included in Washington rates.

<u>Jurisdictional Allocation Factor</u>

Q. ARE THERE OTHER PROBLEMS WITH THE WCA MODEL?

A. Yes. In the model, the fixed costs of production plants (generally referred to as demand-related costs) are allocated to jurisdictions on the basis of the Control Area Energy West ("CAEW") allocation factor. Traditionally, the Company has used a Control Area Generation West ("CAGW") (75% demand (coincident peak) and 25% energy) weighting as the basis for allocation of production demand costs. This is the allocation method built into the Revised Protocol method and to my knowledge has been used by the Company in all recent cases in Washington and other states. The Company does not justify the use of the CAEW on the basis of cost causation, but rather on the basis of simplicity.[18/] Because Washington has a higher load factor than other states, this approach results in higher costs

[18/] Exh. No.___(RJF-12) at 7 (PacifiCorp's Response to ICNU DR No. 1.39).

being allocated to the state. The Company's use of the CAEW method is not cost justified, and appears to simply be an opportunistic approach designed to increase Washington revenue requirements. I recommend the Commission reject the CAEW allocation factor and return to the traditional 75/25 demand/energy jurisdictional allocation factor.

Loss Factors

Q. DO YOU AGREE WITH THE LOSS FACTORS USED BY THE COMPANY IN THE WCA MODEL?

A. No. Based on the data provided the by Company,[19/] the forecasted losses used in the WCA and GRID models is 10.95%. However, historical losses for the most five recent fiscal years were only 10.107%. Because the test year revenue requirements should reflect normalized load levels, they should also reflect normalized losses. Because the loss factors for Washington are overstated in both the WCA model and in GRID, the allocation of costs to Washington is overstated. Further, the net power costs on a PACW basis are also overstated because losses for all three states included in the model are overstated as well. Based on PacifiCorp's 1st Supplemental Response to ICNU DR No. 2.6, using the historical loss factors reduces revenue requirements by the amount shown on Table 1.[20/] I recommend the Commission adopt this loss level if it adopts the WCA method.

19/ See Exh. No.___(RJF-12) at 1-5 (PacifiCorp's Response to ICNU DR No. 1.6).

20/ See Exh. No.___(RJF-12) at 9-12 (PacifiCorp's 1st Supp. Response to ICNU DR No. 2.6).

<u>PACE Regulation/Reserve Modeling Adjustments</u>

Q. DOES THE WCA MODEL EXCLUDE ALL OF THE COST RELATED TO SERVING PACE?

A. No, it appears there is an error in the GRID model which requires PACW to provide regulating margins for PACE. This is the current operational practice used by the Company, and has been modeled in GRID for many years. The Company included PACE regulating margins in the WCA version of GRID. Logically, the model should include both the cost and revenues associated with providing this service. Because I am including the dynamic overlay benefits, discussed above, I do not recommend that the Commission remove the costs of providing operating reserves to PACE in the model.

III. NET POWER COST ISSUES

Q. WHAT ARE "NET POWER COSTS" AND WHY ARE THEY IMPORTANT TO THIS PROCEEDING?

A. Net power costs are the variable production costs related to fuel and purchased power expenses, net of power sales revenue. Net power costs comprise a substantial portion of the overall revenue requirement and therefore are a significant component of PacifiCorp's proposed base rates.

Q. PLEASE DISTINGQUISH BETWEEN NET POWER COST ISSUES AND ISSUES RELATED TO THE WCA MODEL.

A. The WCA model issues discussed above relate to the allocation of production costs (both fixed and variable) within the PacifiCorp system. The issues do not necessarily impact the total system level of costs, but rather the allocation of those costs to the Washington jurisdiction. In contrast, net power cost issues arise from modeling assumptions, input data, or logic in the GRID model that would exist irrespective of the jurisdictional allocation method used.[21] Thus, these issues affect the overall level of variable system costs, and to the extent they are changed, Washington's overall allocated costs would change as well.

Short-Term Transaction Modeling

Q. DESCRIBE THE SHORT-TERM TRANSACTIONS MODELED IN GRID.

A. There are two types of short-term transactions modeled in GRID. Short-term firm ("STF") transactions are firm purchased sales contracts with a term less than one year. GRID does not forecast or simulate such transactions. They are just a fixed input with pre-determined energy volumes and prices.[22]

Secondary balancing transactions (hour-to-hour trades) are simulated in GRID. The model either sells or purchases this product at prices based on the input market forward price curve as needed to balance the system.

Q. DO YOU AGREE WITH THE STF MODELING METHODOLOGY?

A. No. There are some serious problems with PacifiCorp's GRID modeling approach. First, the Company included only the trades that it had arranged as of the time it filed its case in October 2006. By itself, this is quite problematic because many additional transactions will be arranged after the filing date and during the test year. Even if the Company performed an update of the GRID study, many short-term firm trades will occur during the FY 2007 test year, days or only hours ahead of their actual delivery. Because the Company attempts to minimize its costs, it will naturally attempt to make profits on short-term trades

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[21] However, the impact of such issues on Washington could vary significantly, depending on the allocation method used.

[22] The model *accounts* for such transactions rather than *simulate* them. No matter what else changes in the model, the short-term firm transactions will remain constant in GRID.

wherever possible and reduce costs by achieving a better system balance. As a result, the volumes of short-term firm transactions will be understated in GRID, and net power costs will likely be overstated. Second, the Company has not demonstrated these short-term firm transactions are needed to serve Washington, or produce benefits commensurate with their costs. Because many of the sales transactions modeled are below market (and because there is a preponderance of sales compared to purchases) these transactions are demonstrably detrimental to Washington ratepayers.

Q. ARE YOU ABLE TO DEMONSTRATE THIS USING GRID?

A. Yes. I performed GRID runs where all short-term firm transactions were removed from the model. This study resulted in a substantial reduction to net power costs. As a result, it is clear that the short-term firm transactions included by the Company in the model failed to provide benefits commensurate with cost to Washington ratepayers. This being the case, the Commission should disallow recovery of these costs.

Q. ARE THERE OTHER REASONS THE COMMISSION SHOULD MAKE THIS DISALLOWANCE?

A. Yes. First, we are left with an obvious question of prudence. It is quite difficult to understand why the Company would end up in such an unfavorable position vis-à-vis the market for its short-term firm sales. It appears the Company made transactions well in advance of the time necessary, with the net effect being to place the Company in a position of betting on a decline in market prices, which never materialized.

Second, while it is possible that the Company may be able to make profitable trades in the future to offset the additional costs of the below-market sales, it will not be possible to reflect all of the short-term firm transactions in the test year because trades that actually take place in the rate effective period will not be reflected in the model, even if an update is performed. This means that the additional benefits of a better balancing of the system and the numerous profit opportunities that the Company's traders will strive to exploit in the months ahead will not be reflected in rates. Consequently, the test year is biased against ratepayers.[23/]

Third, for purposes of establishing permanent, normalized rates, it is unrealistic to assume that unanticipated market fluctuations will always work against the Company. In normal conditions, the Company will likely make as many (if not more) above-market sales as it does below-market ones. Likewise, under normal conditions, the Company will make as many below-market purchases as it does above-market purchases. Over time, the forward price curves will move in various directions, and the Company will likely find as many circumstances where it is above market as below. This being the case, it is unrealistic to assume that normalized rates should reflect a preponderance of below-market transactions.

23/ Under some types of PCAMs, it is possible that the Company could address this problem. However, it is not clear that the Company proposes to include its actual short-term transactions in its PCAM, nor would it be desirable to so, unless there is a way to test whether the Company's actual short-term transactions are used and useful.

Q. COULD PACIFICORP'S PROPOSED PCAM ADDRESS THIS ISSUE?

A. I will discuss the PCAM in more detail later. However, the proposed PCAM would not provide an equitable solution for two reasons. First, it is not completely clear whether or how the Company proposes to incorporate all actual STF transactions in its update process. Mr. Widmer's testimony is rather vague on this point.[24/] Second, assuming the Company is able to reduce cost by a more refined balancing of the system, the deadband and sharing mechanism would allocate some of the benefits to the Company, everything else being equal.

Q. HOW DO YOU PROPOSE THE COMMISSION ADDRESS THIS ISSUE?

A. I recommend that the Commission remove all short-term firm transactions from GRID. From a modeling perspective, this will result in secondary balancing transactions taking the place of short-term firm purchases and sales in GRID. This will price 100% of system balancing requirements at the forward curve price used in the model. While the Company might argue that this is unrealistic, in fact, under the Company modeling, much of the system's balancing requirements are already priced based on the forward curve (via the modeling of secondary balancing transactions) because the balancing transaction volumes in the model are well above historical levels. Table 1 shows the impact of this adjustment.

Long-Term Contract Modeling In GRID

Q. DOES GRID MODEL LONG-TERM POWER CONTRACTS?

A. Yes. The Company includes the costs and energy produced by all of its long-term contracts in GRID, along with its thermal generation resources in order to project

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24/ Exh. No.___(MTW-1T) at 30.

normalized net power costs. I will discuss issues related to PacifiCorp's long-term contracts in the following sections of my testimony.

<u>Sacramento Municipal Utility District ("SMUD") Contract</u>

Q. DISCUSS THE CIRCUMSTANCES UNDERLYING THE SMUD CONTRACT.

A. This is a 30-year contract with a price that is far below market. This issue has never been decided by the WUTC, because prior Washington cases were either settled or the overall requested rate increase was rejected. Ironically, the history of the Company's proposed treatment of this contract in prior Washington cases was based on prior decisions made by the *UPSC*, not the WUTC.

In 2001, the UPSC required a revenue imputation for PacifiCorp's contract with SMUD on the basis that the prices in the SMUD contract were unreasonably low. In its Final Order in Docket No. 01-035-01, the UPSC summarized the history of this issue:

> As in the immediately preceding general rate case for this Company, Docket No. 99-035-10, this Commission is asked to impute revenues to a 1987 long-term firm wholesale contract with SMUD to counter the contract's adverse impact on the net power cost portion of jurisdictional revenue requirement. In that Docket, the Commission did order imputation because the contract obligated the Company to serve SMUD at $16.85 per MWh at the time it was entered, a rate much below the then-current rate for power. In addition, SMUD paid the Company $94 million at the outset of the contract that it retained and was not used to benefit ratepayers. Nor was this the first time the imputation had been made. In connection therewith, both here and in other PacifiCorp jurisdictions, a contract with Southern California Edison (SCE) entered at about the same time for $42 per MWh had been considered an appropriate benchmark for imputation. The evidence in Docket No. 99-035-10 showed that the SCE contract had been renegotiated to a rate of $37 per MWh due to structural changes in the wholesale market. In other words, the Commission recognized that wholesale prices, which had fallen, were now on a

> different path. This, and the fact that the renegotiation was closer in time to the test period, persuaded the Commission to select the $37 rate as the basis for imputation, a rate indicating how such a contract might perform over time.[25]

Q. HAS THE COMPANY MADE AN ADJUSTMENT TO ITS TEST YEAR TO REFLECT THE SMUD CONTRACT REVENUE IMPUTATION IN THIS AND OTHER JURISDICTIONS AS WELL?

A. Yes. Since the above referenced 2001 Utah case, the Company has used the $37/MWh price for imputation of revenue in all jurisdictions. However, the WUTC has never decided that the $37/MWh was a reasonable price in a contested proceeding, as discussed above. There are three important reasons why the WUTC should address this issue now.

First, this issue gains significance under a Washington specific allocation method, and the treatment approved should reflect the policies of the WUTC, not the UPSC.

Second, wholesale power prices have continued to increase since the adoption of the Utah order in the 2001 case. Indeed, the SCE contract that was the basis for the $37/MWh was renegotiated and the most recent contract prices have been much higher. Consequently, the $37/MWh is no longer reasonable or compensatory, even compared to the SCE contract.

Finally, and even more significant, the SCE contract terminated in September 2006. Originally, the SCE contract was a 20-year contract. Because the SCE contract was selected by the UPSC as a prudent benchmark contract contemporaneous to the SMUD contract (actually, the SCE contract post dates the SMUD contract), there is no longer any basis for the $37/MWh price.

[25] Re PacifiCorp, UPSC Docket No. 01-035-01, Report and Order at 24-25 (Sept. 10, 2001).

Consequently, the Commission should decide on the proper basis for handling this issue for the remaining 10 years of the SMUD contract, even if it believes that the SCE contract was a reasonable benchmark in the past.

Q. WOULD IT BE REASONABLE TO USE THE CONTRACTUAL PRICE?

A. No. The contractual price (approximately $18.5/MWh in recent months) is far below market and is simply not compensatory.

Q. WOULD IT BE APPROPRIATE TO USE THE $37/MWH PRICE?

A. No. This price is substantially below the current market, and below even the most recent renegotiated price of the SCE contract of $60/MWh. The SMUD contract is primarily for on-peak power, so ratepayers are clearly subsidizing the contract even at $37/MWh.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission find the SMUD contract was not prudent and not used and useful. Removing the contract from GRID substantially reduces net power costs. As a result, the contract costs far outweigh the benefits. Given the imprudence of the original transaction, this is a proper treatment.

Should the Commission believe the historical treatment tied to the SCE contract worthy of consideration, I recommend that the Commission assume that, like the SCE contract, the SMUD contract would have terminated after 20 years. As a result, I would remove the SMUD contract from the GRID power cost study. This is equitable because, after the adoption of the $37/MWh price several years ago, the contract has been subsidized by ratepayers due to its below-market price. Because the Company obtained a benefit from use of the SCE contract as a pricing benchmark, it should now be required to assume all of the risks associated with the limited term of the SCE contract. Under either approach, the SMUD contract should be removed from GRID, reducing net power costs by the amount shown on Table 1.

Centralia Sale/TransAlta Contract

Q. EXPLAIN WHY YOU BELIEVE THE CENTRALIA SALE IS AN IMPORTANT ISSUE IN THIS PROCEEDING.

A. Before the sale of the Centralia plant, PACW had far more native capacity available than it does at present. While the Centralia sale case (Docket Nos. UE-991255, UE-991262, and UE-991409) primarily dealt with the question of the public interest of the sale and the allocation of the gain, it did not specifically address rate case treatment of all Centralia related costs. As all of PacifiCorp's prior base rate cases occur after the sales have been either settled or rejected by the WUTC, there is no WUTC precedent on the matter of Centralia rate case treatment. Important issues related to the risks and rewards of the sale have yet to be addressed by the Commission. Now, owing to the use of the WCA method, Centralia takes on far greater significance than in the past. Centralia now represents a very large "missing piece" of the PACW supply puzzle that the Commission should carefully consider for not only this case, but for the cases in the years ahead.

Q. HOW DOES THE CENTRALIA SALE IMPACT PACIFICORP'S NET POWER COSTS IN THE WCA MODEL?

A. The Centralia sale has contributed substantially to the Company's need to increase purchased power expenses. Without the Centralia sale, the Company would have had more than enough energy to meet its native system requirements with low-cost coal and hydro generation.

Q. DID SOME OF THE PARTIES RAISE OBJECTIONS TO THE SALE IN THE CENTRALIA PROCEEDING?

A. Yes. Based on the Order in the Centralia sale proceeding it is quite apparent that both Staff and Public Counsel were concerned about the risks resulting from this sale, including greater exposure to wholesale market risks. ICNU also advocated a "no harm" standard be applied.[26/]

Indeed, even the Company's own quantitative risk analysis showed that Centralia would have a positive Advantage Over Market ("AOM") in the projections presented in that case. This means even the Company recognized the likelihood that customers would be worse off as a result of the sale. In the end, the Company made a decision to *increase* its wholesale market risk, despite the knowledge of those risks and concerns and objections voiced by the parties to that case.

Q. HOW DID THE COMMISSION ADDRESS THESE CONCERNS?

A. In recognition of this controversy, the Commission stated that neither the customers nor the shareholders will bear all of the risks associated with the sale. Instead the Commission adopted a policy that stated "risk should follow reward" and "benefit should follow burden."

> In general the Commission relies on the broad principle that reward should follow risk and benefit should follow burden. In this particular transaction, both ratepayers and shareholders have and will incur risks and burdens. In addition to the financial risks and burdens borne by ratepayers, ***shareholders bear legislative and***

26/ Re Avista Corp., WUTC Docket Nos. UE-991255, UE-991262, and UE-991409, Second Supp. Order at ¶¶ 21, 25, 26 (Mar. 6, 2000).

> ***market risks***, and additionally bear the regulatory burden of prudently managing their resources, which multiple ownership can make difficult. As both shareholders and ratepayers have incurred risks and burdens, both should also share in the benefits of the sale. The remaining gain is thus *one* of the benefits, which, when considered with other benefits and burdens, must be fairly allocated.[27/]
>
> * * *
>
> Given the risks and burdens borne by the ratepayers and shareholders, and given the other benefits they stand to gain from the sale, we find that it is fair in this case to allocate the appreciation between ratepayers and shareholders. When we apply the principles of *Democratic Central* to the facts of this case, we conclude that one half of the appreciation should go to shareholders, and one half to ratepayers.[28/]

In reaching this decision, the Commission enunciated a policy that would share the gain on the sale equally between customers and shareholders, while at the same time sharing the risks (most notably market risk.) In the case at hand, the Company has conveniently ignored this fact, and instead proposes to place the entire risk of higher power market prices on the customer. Since the Company retained half of the gain from the sale, under the principle that *risk should follow reward*, it should bear half of the risk. Under these circumstances it is not reasonable to shield the Company from <u>all</u> of the risks of its controversial decision to sell the plant.

Q. DID THE COMPANY OBTAIN SUFFICIENT ENERGY FROM THE TRANSALTA BUYBACKS TO REPLACE CENTRALIA?

A. No. The Company obtained only enough energy from the buybacks to replace 74% of the Centralia generation for the test year. Given that the Company was well aware at the time of the sale that there was certainly substantial market risk

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[27/] <u>Id.</u> at ¶ 84 (emphasis added).
[28/] <u>Id.</u> at ¶ 86.

associated with the transaction, its decision to replace only part of the generation for the plant was questionable to say the least. This shortfall resulted in an increase in purchased power costs of nearly $16 million on a PACW basis and approximately $3.6 million for Washington under the WCA model. Even more significant is the fact that after June 2007, the TransAlta buybacks terminate and the Company will be left without any permanent supply to replace the Centralia generation. This contract termination will result in additional costs per year of $45 million for PACW, and, under the WCA method, added costs of $10 million per year for Washington. The Company assumes customers should bear 100% of these added costs. This is not a reasonable rate treatment in light of the Commission's principle that risk should follow reward.

Q. HOW DO YOU RECOMMEND THE COMMISSION ADDRESS THIS ISSUE?

A. As discussed above, the Commission decided to give the Company the opportunity to make the sale, and also apportioned 50% of any associated gain to the Company. Under these circumstances, it is unreasonable to saddle ratepayers with all of the risks that have resulted from the sale. Unless the Commission apportions some of the costs of the unreplaced power to the Company, the ratepayers will have been given 50% of the gain on the sale, but bear 100% of the risks. As a result, I recommend that 50% of the cost associated with additional replacement power costs for Centralia be allocated to the Company. This adjustment reduces the requested claim by the amount shown on Table 1. Unless this adjustment is made, an unreasonable shifting of the risks of the Centralia sale between the Company and ratepayers will occur.

Q. HAVE OTHER COMMISSIONS ADDRESSED THE SAME ISSUE IN THE PAST?

A. Yes. In Wyoming Docket No. 20000-ER-02-184, both the Consumer Advocate Staff and Wyoming Industrial Energy Consumers ("WIEC") proposed a similar adjustment. The facts were essentially the same in the Wyoming case, because the Wyoming Public Service Commission ("WPSC") allocated 36% of the Centralia gain to the Company.[29] In its final order in Docket No. 20000-ER-02-184, the WPSC noted that PacifiCorp agreed in concept with the adjustment (though disputed the calculation of the disallowance).[30] The WPSC stated that it ultimately accepted the adjustment as part of the basis for the decision to deny PacifiCorp the requested rate increase to pay for excess power costs during the 2001 power crisis.[31] Given this background, the Commission can be confident it is on firm footing in making the adjustment related to this issue shown on Table 1.

GP Camus Contract

Q. DO YOU AGREE WITH PACIFICORP'S MODELING OF THE GP CAMAS COGENERATION PROJECT?

A. No. The Company has overstated the generation purchased from this project compared to recent actual data. It is apparent that the generation from this project has declined steadily for the past several years. Because this reduction appears to be continuing, I trended its generation for the four-year period ending March 2007. This adjustment reduces net power costs by the amount shown in Table 1.

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[29] This was an issue I first raised in a prior Wyoming docket that was addressed by the Consumer Advocate staff and another witness in Docket No. 20000-ER-02-184.

[30] Re PacifiCorp, WPSC Docket No. 20000-184-ER-02, Final Order at ¶ 192(b) (Mar. 6, 2003).

[31] Id. at ¶ 206.

Modeling Adjustment

Hydro Modeling

Q. DISCUSS THE SIGNIFICANCE OF HYDROELECTRIC RESOURCES TO PACW'S POWER SUPPLY COSTS.

A. Hydro resources supply 30% of the PACW system load. As a result, modeling of all aspects of hydro generation is critical to the development of sound estimates of normalized net power costs for the Company. A critical element in the determination of net power costs is the proper technique for normalization of hydro generation. There are a number of issues surrounding this topic, the most important being the selection of a proper set of water years for use in simulating PacifiCorp's power costs.

Q. PLEASE EXPLAIN THE CONCEPT OF "WATER YEAR" SIMULATIONS.

A. The annual supply of hydro electric energy is a function of snowpack, snowmelt, run off, and precipitation in the mountains surrounding the river systems that host the dams operated by PacifiCorp and other regional utilities. As a result, the availability of hydro generation is largely a matter of weather and geological factors. Because weather is subject to fluctuation over time, hydro generation varies substantially from year to year. For this reason, it is important to develop power supply cost estimates that reflect the variations in hydro generation over time. This has typically been done by hydro-dependent utilities through use of simulation models that estimate power supply costs as a function of available hydro generation and many other inputs. The most common approach has been to simulate historical water conditions over a large number of years, averaging the final results of the individual water year scenarios. This methodology develops an "expected value" power supply cost.

Q. DOES USE OF MULTIPLE WATER YEAR SCENARIOS GIVE RISE TO ANY SPECIAL ISSUES FOR COMPANIES SUCH AS PACIFICORP?

A. Yes. As early as the 1970s, multiple water year scenarios were used by utilities in Washington to estimate power supply costs for rate case purposes.[32/] The question of how many, and which, water years provide a reasonable simulation has been an issue in many previous proceedings before the WUTC. For the past several cases, PacifiCorp has proposed a 40-water-year simulation. However, in the 2004 case, some important modifications to that method were proposed by the WUTC Staff, and later adopted by the Company and the Commission as part of a contested settlement.

Q. DISCUSS THE 2004 PACIFICORP CASE.

A. In Docket No. UE-032065, PacifiCorp filed its request using a 40-water-year study (1939-1978); based on existing precedent for that Company. However, Staff witness Buckley recommended use of a 40-year "filtered water" study, where "extraordinary" water years (those more than one standard deviation beyond the mean annual generation) were excluded. Mr. Buckley's basis for this proposal rested on the fact that utilities would request deferrals or Power Cost Adjustment mechanisms ("PCAs") in situations where abnormal or extreme hydro conditions occurred:

32/ I recall this from my employment with Puget Sound Power and Light in the late 1970s.

Q. Why does Staff propose a different methodology at this time for this PacifiCorp?

A. Two factors led Staff to conclude that an alternative approach is appropriate. The first is the recent, very real tendency for the regulated electric utilities to request rate relief when higher than expected actual power supply expenses occur due to "unforeseen" events. Bad water-years and their effect on actual power supply costs have been cited as one of the unforeseen events.

* * *

Two of the three regulated electric utilities now have some form of power cost adjustment mechanism. A Washington islanding or stand-alone approach may include some form of hydro adjustment to address the variability in generation from hydro resources in the Western Control Area. Such a hydro adjustment would address the more significant variations in water conditions throughout the region. It is therefore unnecessary, and even incorrect, to include the power supply costs associated with all water year conditions in the determination of the base power supply costs when a hydro adjustment mechanism exists. The effects on power supply expense of water years above or below some level can be addressed in the mechanism.

* * *

There is no need to burden Washington customers with rates designed to recover long-term extremes in power supply costs due to stream flow variations. In the event an extreme year occurs that adversely affects power costs between now and the next general rate case, the Company can make a filing to recover those costs. The adoption of this water year methodology is also appropriate under any scenario. Whether through a hydro adjustment mechanism or [through] a separate filing requesting relief from drought conditions, it may be in the best interests of customers to see the cost effects of stream flow variations. *Embedding the effects of the more extreme stream flow conditions is tantamount to paying an insurance premium and then hoping the Company will have sufficient funds to pay the claim.*[33/]

[33/] WUTC v. PacifiCorp, WUTC Docket No. UE-032065, Exh. No. 581 at 124-27 (Buckley Direct) (emphasis added).

Q. DID THE COMMISSION ACCEPT STAFF'S PROPOSAL IN THE PACIFICORP CASE?

A. Yes. However, the PacifiCorp case resulted in a contested settlement between Staff and the Company. In the stipulation, the Company agreed to Staff's proposed hydro normalization adjustment. While this stipulation was opposed by ICNU and Public Counsel, to my knowledge, no party opposed the hydro normalization adjustment. Appendix B to the stipulation document in the PacifiCorp case clearly identified the fact that "extraordinary" hydro years were excluded from the normalization.

Q. SHOULD THE COMMISSION EXCLUDE EXTRAORDINARY WATER YEARS FROM THE NORMALIZATION PROCEDURE AS MR. BUCKLEY RECOMMENDED IN DOCKET NO. UE-032065?

A. Yes. Mr. Buckley's proposal was a sensible recommendation given the Commission's current regulatory policies and practices as applied to PacifiCorp. Indeed, because the Company has already requested a PCAM in this and prior cases, and the Company was granted the right to defer costs related to a hydro deficit in Docket No. UE-050684, Mr. Buckley's proposal is even more appropriate in this case than it was in 2004.

Q. EXPLAIN THE NEXUS BETWEEN DEFERRALS OF EXCESSIVE POWER COSTS AND THE HYDRO NORMALIZATION TECHNIQUE.

A. Putting aside, for the moment, the issue of the PCAM, the option of a utility being allowed to defer excess power costs in extreme event water years (e.g., a drought) necessitates the exclusion of such water years in the hydro normalization procedure to eliminate a potential problem of double recovery.

Q. CAN YOU PROVIDE AN EXAMPLE TO ILLUSTRATE THIS?

A. Table 2 presents a hypothetical example to explain this problem. In the example, the utility uses a power cost model to compute normalized power costs on the basis of five different hydro generation scenarios. The table shows a hypothetical company that has an average of 500 megawatts ("MWs") of hydro, and replacement power costs $30/MWh. It shows that under normalized ratemaking customers are charged $100 million per year as the average cost of power based on average hydro over a five-year period (simplified from the 40 years actually used). Over five years, the results would all average out and customers would pay the total actual cost of power supply costs, $500 million. The $500 million figure includes both good and bad hydro years. The normalized cost of $100 million is lower than the cost of power in below average hydro years, but higher than the cost of power in good hydro years. By using the average value, a "premium" is built into the normalized cost of power in good years that provides a form of "insurance" against bad hydro years.

Assume now that year five is the worst hydro year and the utility requests a deferral to allow it to ultimately recover the additional power costs. If regulators allow the Company to have a deferral in a bad hydro year, they get the benefit of the "premium" built in during the good years, and then effectively charge the actual cost in year five. Under this scenario, ratepayers pay the normalized cost of power ($100 million) for the first four years and the actual cost of power in year five. The total cost of power to customers in that scenario is

$526 million, resulting in an overcharge to customers of $26 million over the five-year period.

Table 2
Example of Overcollection Problem

Year	Hydro Average MW	NPC-M$	Normalized Ratepayer Cost	Ratepayer Cost with Deferral Y 5
1	600	73.7	100.0	100.0
2	550	86.9	100.0	100.0
3	500	100.0	100.0	100.0
4	450	113.1	100.0	100.0
5	400	126.3	100.0	126.3
Average	500	100.0	100.0	
Total Ratepayer Cost		500.0	500.0	526.3
			Overcollection	26.3

In the example above, the higher than normal costs of a bad hydro year ($26 million) are averaged into rates every year. However, instead of getting a "free pass" when the bad hydro year actually arrives, customers are now required to pay for bad hydro conditions as well. When above normal hydro conditions occur, customers pay the normalized cost and the company keeps the savings. When below normal hydro conditions occur, the company requests a change to the rules of the game and asks for a deferral to recover its total cost. This is a "heads I win, tails you lose" type of hydro normalization process.

Q. GIVEN THE PROBLEM ILLUSTRATED ABOVE, WHY WOULD REGULATORS ALLOW DEFERRALS IN POOR HYDRO YEARS?

A. While regulators may be concerned about the inequity illustrated above, the reality is that financial exigencies may force the Commission to approve a deferral. This illustrates the problem alluded to by Mr. Buckley in the testimony quoted above stating that customers pay the "insurance premium" hoping the Company will be able to "honor the claim."

Q. WHAT IS THE IMPACT OF USING THE "FILTERED WATER" METHODOLOGY IN THIS CASE?

A. Exhibit No.___(RJF-8) shows the GRID model power cost results based on the filtered and non-filtered approach. Mr. Buckley's approach, using PacifiCorp's 40 years of water data would result in power supply costs substantially less than the Company non-filtered proposal. I recommend the Commission adopt this adjustment, reducing power costs by the amount shown on Table 1. I will also tie this treatment into my alternative to PacifiCorp's PCAM proposal to be discussed later.

<u>Thermal Deration Factors</u>

Q. EXPLAIN THE SIGNIFICANCE OF THERMAL DERATION FACTORS IN GRID.

A. In GRID, thermal deration factors (also called outage rates) control the amount of generation available from thermal units. The more energy available, the lower net power costs. If a generator has an average outage rate of 5%, GRID assumes a thermal deration factor of 95%. This means that only 95% of the unit's capacity is available to produce energy. The remaining capacity is assumed to be permanently on outage. The Company uses a compilation of outages over the most recent 48-month historical period (April 2002 to March 2006) to compute the deration factors for its thermal plants. The purpose of using 48 months is to "normalize" or smooth out variations that might affect a single year.

Q. HOW DOES THE COMPANY MODEL UNPLANNED OUTAGE RATES IN GRID?

A. The Company computes a different unplanned outage rate for each month based on the 48-month rolling average. This procedure marks a significant departure from the modeling methods used by the Company for the past ten years or more. In the past, the Company assumed that unplanned outages would occur with the same probability every month of the year. In this case, the Company now assumes outage rates will vary by month.

Q. IS THIS AN INDUSTRY STANDARD PRACTICE?

A. Most definitely not. PacifiCorp's approach is quite unusual and certainly not industry standard. While I am aware that a few utilities have briefly experimented with modeling seasonal outage rates, the vast majority of utilities assume a constant outage rate throughout the year. The primary reason for this is that there are few physical factors affecting thermal power plant operation that would result in outage rates varying on a monthly or seasonal basis. There is really no engineering basis to assume a generating unit would be more reliable in January than July, for example.

Further, unplanned outages are quite random by nature, and use of monthly statistics can produce very misleading results. For example, a unit could be out the entire month of May, resulting in a 100% outage rate for that month. Assuming the unit had a 10% outage rate otherwise, the Company's method would assume that every May, there was a 32.5%[34/] chance the plant would be out of service, but only a 10% likelihood for the remaining eleven months. Rolling a

[34/] (100+3*10)/4.

single "bad month" into the overall 48-month average would produce a 48-month outage rate of 11.875%[35/] overall. I submit that a single outage rate of 11.875% every month is more realistic than assuming a 32.5% outage rate each May and a 10% outage rate every other month.

Q. CAN YOU PROVIDE A SIMPLE ANALOGY THAT EXPLAINS THE FALLACY OF THE COMPANY'S APPROACH?

A. Yes. The Company's approach is similar to assuming that because a random event occurred in a particular month in the past, it would likely occur at the same time in the future. For example, if my car broke down on in February 2006, it would likely break down again in February 2007. However, this is superstition, not logic. It is analogous to fearing that something "bad" might happen every Friday the 13th!

Q. DOES THE COMPANY'S APPROACH MAKE SENSE WITHIN THE CONTEXT OF NORMALIZATION?

A. No. The use of monthly outage rates defeats the purpose of a 48-month normalization period. In effect, the Company has replaced 48 months of data with four months of data for each individual month. However, mere statistical variations are such that four single months of data will be far too variable to "normalize" outage rates. If monthly outage rates are used, then a much longer period of time should also be employed.

Q. DO YOU HAVE AN EXHIBIT THAT FURTHER ILLUSTRATES THE FALLACY OF PACIFICORP'S APPROACH?

A. Yes. Exhibit No.___(RJF-9) shows an analysis of the outage rates for Jim Bridger Units 1-4. Because these units are all of the same size, fuel type, location

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35/ (47*10+100)/48.

and similar designs, one would expect that if the monthly outage rate modeling made sense, there should be some correlation between their monthly outage rates. In other words, if there are causal factors that result in a definite monthly pattern of outages, it should affect all units at the station in a comparable manner. However, the exhibit shows there really is no discernable pattern in the monthly outages of these units. Indeed, there is no statistically significant correlation between the monthly outage rates of these units. It is apparent from the figure that the monthly variations about the mean amount to nothing more than "statistical noise" or "random chance." This strongly suggests there is no basis, other than superstition, underlying the Company's proposal to apply this novel monthly outage rate modeling technique.

Q. DOES THE MONTHLY OUTAGE RATE MODELING INCREASE NET POWER COSTS IN GRID?

A. Yes. Given the lack of a sound engineering basis or common sense argument underlying this approach and the lack of any statistical support for it, I am forced to conclude this is little more than "numerology." It certainly appears this is a one-sided adjustment proposed by the Company for no purpose other than to increase power cost estimates. I recommend that the Commission reject the monthly modeling of outage rates and reduce net power costs by the amount shown on Table 1.

Thermal Ramping

Q. DO YOU RECOMMEND THE COMMISSION ACCEPT THE THERMAL RAMPING ADJUSTMENT CONTAINED IN THE GRID STUDY?

A. No. This adjustment was proposed by the Company ostensibly to better represent the operation of thermal units. PacifiCorp has adopted this technique in several recent cases in other states, motivated by a dubious assumption that GRID was producing an excess of coal-fired generation.[36/] To address the ramping issue, PacifiCorp creates "phantom outages," inflating its outage rates. However, all of the Company's recent cases in Oregon, Utah, Washington and Wyoming have been settled (at least regarding this issue) or dismissed, so there is no regulatory decision in any state supporting this technique.

Q. IS MODELING OF THERMAL RAMPING IN THE MANNER USED BY THE COMPANY STANDARD INDUSTRY PRACTICE?

A. No. Again, based on my nearly thirty years' experience in working with various production cost models, this approach is extremely unusual and contrary to standard industry practice. The North American Energy Reliability Council ("NERC") publishes a standard formula for computation of forced outage rates, and the approach proposed by the Company is inconsistent with the NERC formula.

Q. ARE YOU AWARE OF ANY INSTANCE WHERE A UTILITY PROPOSED TO INCLUDE ENERGY LOST DUE TO RAMPING IN THE OUTAGE RATES USED IN A POWER COST MODEL?

A. There is only one other case that I am aware of. In Oregon Docket No. UE 139, Portland General Electric Company ("PGE") proposed a similar modification to

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[36/] Re PacifiCorp, OPUC Docket No. UE 170, Exhibit PPL/604 at 2 (Supp. Direct Testimony of Mark Widmer).

outage rates for the Colstrip plant to solve a similar assumed problem of generation from its model exceeding actual generation ("lost generation"). In that case, the Commission flatly rejected the PGE proposal:

> ICNU disapproves of PGE's calculations in modeling planned outages for the Colstrip plant. ICNU notes that the [NERC] has promulgated a standard equation to estimate the forced outage rate of a particular plant. In estimating the forced outage rate for Colstrip, however, PGE modified NERC's standard equation by substituting the plant's capacity factor (CF) for its equivalent availability factor (EAF). ICNU contends that PGE's deviation from standard industry practice is unjustified and arbitrarily inflates PGE's net variable power cost estimate by $1.5 million.
>
> PGE explains it made the adjustment because it obtains less energy from Colstrip than one should expect from the plant's EAF. PGE highlights that it has normally received 1 to 4 percent less generation—based on the plant's CF—than would be expected—given the plant's EAF. To account for this, PGE assigns the "missing generation" to unplanned outages. PGE has not identified any specific reason why the generation at Colstrip has fallen short of potential levels, but speculates that up or down ramping periods, generation variances including minor forced derations, or transmission pathway deratings may be responsible.
>
> * * *
>
> While it appears that an aberration exists in PGE's system that prevents the company from obtaining expected generation levels from the Colstrip plant, we are not convinced that creating "phantom outages" is the appropriate solution. First, PGE's proposed adjustment violates standard industry practice and is contrary to the company's own forecasting methods that it uses for other plants. Second, PGE's adjustment fails to account for the fact that a plant's CF, by definition, will never exceed its EAF, even those that run continuously.
>
> We are also troubled by PGE's decision to make this adjustment despite the fact that it is unable to identify the source of the generation shortfall or to quantify its effect. If the loss of energy from Colstrip is due to minor forced derations as PGE speculates, the company should be able to modify Monet to capture these derations.

> For these reasons, we disagree with PGE's adjustment to a standard industry equation used to compute forced outage rates when outages have nothing to do with the alleged problem.[37/]

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reject the ramping adjustment, reducing net power costs by the amount shown on Table 1.

Regulating Margin Requirements

Q. DO YOU AGREE WITH PACIFICORP'S MODELING OF REGULATING MARGIN REQUIREMENTS IN GRID?

A. No. The Company now assumes an increase in the maximum regulating margin requirements from 125 MW used in Docket No. UE-050684 to 225 MW. The Company provides no justification for this changed assumption in its testimony. Based on discussions I had with PacifiCorp's operating personnel at a technical conference in November 2004, the Company's actual maximum west regulating margin is only 125 MW. The Company used this assumption for many years in GRID, but recently proposed this change. The change was made in Oregon in UE 179, and was opposed by ICNU in that case. The changed assumption was not supported by a change in system operations, but rather a flawed new methodology used by the Company to develop the inputs. UE 179 was settled, so there is no precedent surrounding this issue. I recommend the Commission reverse this data change resulting in a reduction to net power costs by the amount shown on Table 1.

[37/] Re PGE, OPUC Docket No. UE 139, Order No. 02-772 at 23-24 (internal footnotes omitted).

V. PCAM

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. I address the issues raised by PacifiCorp's request for approval of its already defined PCAM. I am not testifying for Public Counsel on this issue because Public Counsel is sponsoring a witness to specifically address the PCAM. Specifically, I show why the arguments the Company uses in support of its proposal are unpersuasive. I also identify a number of problems and flaws in the PCAM proposal. I recommend that the Commission reject the proposed PCAM and present an alternative concept the Commission should adopt, if it decides to implement a PCAM at this time.

Q. PLEASE SUMMARIZE YOUR PCAM TESTIMONY.

A. I have concluded as follows:

1. There are serious design flaws in the proposed PCAM. The proposed PCAM does not address the objections to a PCAM expressed by the Commission in Docket No. UE-050684.

2. The proposed PCAM does not use actual short-term power costs, but instead uses hypothetical "pseudo-actual costs" based on GRID model runs rather than actual data. Because PacifiCorp has also failed to produce a reasonable jurisdictional allocation methodology, its PCAM proposal is unsupportable.

3. The PCAM proposal does not provide protection against extreme or unusual events, but rather allows substantial recovery of certain kinds of ordinary cost increases.

4. PacifiCorp has not demonstrated that a PCAM is needed. The PCAM proposal is poorly explained and not adequately justified in PacifiCorp's testimony. The Company fails to address many problems inherent in its PCAM concept.

5. Owing to the looming expiration of the TransAlta contract, the PCAM really amounts to a $5 million rate increase in disguise.

6. While I recommend against it, if the Commission decides to adopt a PCAM, I propose a more reasonable alternative to the Commission.

Problems in the PCAM Proposal

Q. SHOULD PACIFICORP'S PCAM BE AUTHORIZED BY THE COMMISSION?

A. No. The PacifiCorp proposal is flawed, poorly justified, and places Washington ratepayers at a substantial disadvantage vis-à-vis the Company and customers in other states. Adoption of the proposed PCAM would be a questionable policy decision at this time. Further, pass through mechanisms reduce incentives for efficiency and increase the overall regulatory burden.

Q. DOES THE COMPANY HAVE A PCAM IN ITS TWO LARGEST STATES, OREGON AND UTAH?

A. No. The Company proposed a PCAM in both states, but later withdrew its request. Adoption of a PCAM would require Washington ratepayers to assume risks not shared by customers in the Company's two largest jurisdictions.

Q. ARE THERE IMPORTANT DEFECTS IN THE PCAM PROPOSAL?

A. Yes. There are practical drawbacks and many policy issues raised by the PCAM proposal. Below I identify the major components of my analysis of the problems with the PacifiCorp proposal:

- Failure to address the Commission's concerns as expressed in Docket No. UE-050684;
- Use of GRID model runs instead of actual short-term costs;
- Lack of a reasonable jurisdictional allocation method that would facilitate computation of actual costs to be included in the PCAM;
- Lack of an appropriate deadband and sharing mechanism;

- Lack of justification/need for a PCAM; and
- Likelihood of a built in rate increase in 2007.

1. <u>Failure to Address Commission Concerns in Docket No. UE-050684.</u>

Q. DOES PACIFICORP'S PROPOSED PCAM ADDRESS THE CONCERNS THAT LEAD THE COMMISSION TO REJECT ITS PCAM PROPOSAL IN DOCKET NO. UE-050684?

A. No. While the Company does address a few of the Commission's concerns (in a rather self-serving manner) it did not address the Commission's most pressing concerns. In Docket No. UE-050684, the Commission cited three particularly important issues in its rejection of the proposed PCAM:

> In sum, we reject the proposed PCAM for three reasons: 1) It should focus on short-term costs subject to market volatility or other extraordinary events that are beyond the Company's control, and should not include costs for new generation; 2) The 90/10 sharing band and the absence of a deadband do not adequately balance risks and benefits between shareholders and ratepayers, and; 3) An acceptable allocation methodology is a prerequisite to establishing a PCAM.[38/]

PacifiCorp's new proposal continues to fail all three counts. <u>First</u>, it does not focus on actual short-term costs, but instead relies on hypothetical "pseudo-actual" costs. <u>Second</u>, it fails to use a reasonable deadband, and for power cost variances in excess of $7.4 million it adopts the same 90/10 sharing already rejected by the Commission. <u>Finally</u>, as discussed earlier, the Company has failed to develop a reasonable allocation methodology. Indeed, the most compelling argument against PacifiCorp's WCA methodology is that the Company contends it cannot even compute the actual costs to be applied to Washington. I will elaborate on each of these points in the following sections of this testimony.

38/ WUTC Docket No. UE-050684, Order No. 04 at ¶ 99.

2. Use of the GRID Model for Actual Costs/Jurisdictional Allocation

Q. IS THE PROPOSED PCAM BASED ON ACTUAL SHORT-TERM COSTS?

A. No, and this fact illustrates a major problem with the proposed WCA jurisdictional allocation methodology. Rather than develop a PCAM that applies to actual short-term costs, the Company instead proposes to manufacture pseudo-actual costs by use of GRID model runs.

Q. WHY DOESN'T THE COMPANY USE ACTUAL SHORT-TERM COSTS IN THE PROPOSED PCAM?

A. It seems quite apparent that the reason for this is that, under the WCA methodology, the Company has developed no technique for separating WCA power costs from system power costs.[39/] As a result, the Company falls back on its truncated (PACW only) GRID model to provide a dispatch of western resources on a stand-alone basis. A fundamental problem is that without some form of actual cost to compare the model against, there is no basis for assuming the model provides realistic results. Indeed, the model could be off by tens of millions of dollars for PACW, but there is no way to determine whether it is accurate or not. As shown earlier, on the basis of my approximations, this problem indeed exists. My actual cost analysis shows the Company's model has greatly overstated actual PACW power costs. As a result, it is not useful for purposes of developing a PCAM and should not be used by the Commission for such purposes.

[39/] See Exh. No.___(RJF-12) at 6 (PacifiCorp's Response to ICNU DR No. 1.27). In this response, the Company admits that it has not developed actual power costs for PACW. In its Response to ICNU DR No. 1.48, the Company admits that it has not developed any analysis of historical costs that would have been recovered under the PCAM. Exh. No.___(RJF-12) at 8.

Q. HOW DOES THE COMPANY PROPOSE TO COMPUTE THE PSEUDO-ACTUAL COSTS IN THE PCAM?

A. While this is a very important issue, Mr. Widmer is quite vague on the matter. On page 30 of his testimony he provides a terse explanation, indicating that "actual market prices for electricity and natural gas, fuel costs, hydro generation, retail loads, forced outages, planned maintenance" and certain new wholesale transactions will be input into the GRID model.[40/] The new model results will then be compared to the projections used in setting rates. Based on the difference between these two GRID runs, the Company would then produce its annual PCAM update.

Q. IS THIS A REASONABLE PROCEDURE?

A. No. The resulting numbers are neither actual costs, nor are they projections. In my experience, the great majority of regulatory commissions use actual costs in PCAM-type procedures. While Oregon has used forward-looking projections (for PGE and PacifiCorp) as part of an annual power cost update process, this is not the same as using a model as a substitute for actual costs in PCAM. I am not aware of any state that uses a model fed with a veritable witches' brew of both actual and projected data to develop power cost adjustments on an annual basis. Indeed, when offered a mechanism of this very sort (in the form of a settlement between the OPUC Staff and PGE in Oregon Docket No. UE 165/UM 1187), the Oregon Commission rejected the proposal out of hand.[41/]

40/ Exh. No.___(MTW-1T) at 30.

41/ Re PGE, OPUC Docket Nos. UE 165 and UM 1187, Order No. 05-1261 (Dec. 21, 2005).

Q. WHAT IS THE FUNDAMENTAL PROBLEM WITH THE PCAM PROPOSAL?

A. Ratepayers should either be charged normalized projected costs (developed in a rate case allowing all parties due process sufficient to test the assumptions) or verifiable actual costs (subject to a sufficient audit). A combination of some actual and some projected data plugged into an untested (and ever changing) model would be a unique and highly questionable regulatory experiment.

Q. DO YOU HAVE ANY SPECIFIC CONCERNS REGARDING THE ACTUAL COST COMPONENTS THE COMPANY PROPOSES TO MODEL IN THE PCAM?

A. Yes. First, the Company proposes to reflect "actual market prices" for natural gas and electricity. However, Mr. Widmer's testimony does not provide any explanation as to how this data will be applied or from where it will come. For example, Mr. Widmer refers to actual market prices for COB and Mid-C being used in the model, but he does not indicate whether these would be published indices, or actual prices paid by the Company.[42/] Further, market prices vary constantly. The Company does not specify whether it will use hourly prices in the model, or generate hourly prices from day-ahead prices, for example. This issue turned out to be a major complication in the above referenced PGE case and required substantial changes to the model to accept the data.

Second, PacifiCorp's only gas-fired generator in PACW (Hermiston) has a long-term contract. There is no reason why actual gas market prices should be used in the model, since the Company is not actually paying market prices for its

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42/ Exh. No.___(MTW-1T) at 31.

gas. Use of actual market gas prices would most certainly result in over-recovery of the Company's gas costs.

Third, the Company proposes to use actual forced outage rates and hydro generation in the model. However, the Company does not specify whether the model will be required to run with the actual outages as they occur, or will use annual or monthly averages. This gives the Company a lot of flexibility tailoring these inputs to achieve results it deems desirable. With respect to hydro, the Company does not indicate whether it will use actual hourly, weekly, or monthly hydro generation in the model. If it does not use the actual dispatch sequence, it is unclear how it will develop the hourly figures used in the model.

Finally, the Company proposes to exclude some (but not all) "new" resources. This would include replacement contracts, or even contract extensions. For example, as discussed above, the TransAlta contract expires in June 2007. Under the Company proposal, even if the contract was extended with the same quantities and pricing provisions, the resource would be removed from the model and priced at the then current market. This would produce a substantial increase in net power costs in the GRID model, even though that would not be true for the Company's actual costs. Likewise, if a highly unfavorable sales contract (i.e. SMUD) were to be terminated, the Company would continue charging customers as though it continued indefinitely.

While the Commission did express concern about including "new resources" in a PCAM in its order in Docket No. UE-050684, it did not even suggest that contract extensions or new sales should be ignored. My reading of the Commission's order on this point was that it did not want the PCAM to serve as a substitute for a general rate case when the Company obtained a long-term contract for a major new plant (e.g. a new combined cycle plant such as Hermiston), not that it intended to allow the Company to charge market prices every time a contract expired. Because the Company has the flexibility to decide when rate cases are filed, allowing the Company such latitude in excluding contracts and sales is most certainly subject to abuse. The Company would be able to avoid rate cases in cases where favorable transactions were entered into (or unfavorable ones ended), and file rate cases in the opposite set of circumstances.

In the end, the biggest problem with the PacifiCorp proposal is that, owing to the lack of a reasonable jurisdictional cost allocation method, the Company has not developed a PCAM based on actual costs.[43/] Instead the Company proposes a PCAM that deals with manufactured pseudo-actual costs that are neither the actual short-term costs usually applied in a PCAM, nor are they the normalized costs used in setting base rates. The result is likely to be a PCAM the Company is able to exploit for its gain at ratepayers' expense.

3. Deadband and Sharing Mechanism

Q. DESCRIBE THE DEAD BAND AND SHARING MECHANISM IN THE PCAM PROPOSAL.

A. PacifiCorp proposes a deadband of plus or minus $3.0 million dollars, with 60/40 (customer/company) sharing for variances between plus or minus $3.0 and $7.4

[43/] Alternatively, perhaps the Company analyzed this issue, as did I, and came to the conclusions that the model overstates PACW power costs.

million. For all larger variances, the Company proposes to allocate 90% of power cost variances to customers and 10% to shareholders.

Q. IS THIS A REASONABLE SHARING MECHANISM?

A. No. For any power cost variance greater than $7.4 million, 90% of the costs are assigned to the customer. This is unfortunate, because the Commission already rejected the 90/10 sharing mechanism in Docket No. UE-050684, as discussed above. The Company's latest proposal is only slightly different. Once again, the Company pays mere lip service to the Commission's requirements and comes back with a self-serving proposal.

Q. HOW DOES THE COMPANY SUPPORT THIS SHARING MECHNANISM?

A. The Company justifies its PCAM on the basis that it is similar to the current Avista Energy Recovery Mechanism ("ERM"). However, the Company ignored the fact that the surrounding circumstances for Avista and PacifiCorp are quite different. First, the current Avista mechanism was the result of a unanimous stipulation of the parties to Docket No. UE-060181 that grew out of another unanimous stipulation of the parties to Docket No. UE-011595. The earlier case resulted from the fallout of the 2001 western power crisis, which cost Avista's debt its investment grade status. Even in 2006, Avista still had a below investment grade credit rating. Parties to the case, including both ICNU and Public Counsel were well aware of the need to take steps (including use of a PCAM) to address this problem. PacifiCorp's reliance on Avista is misplaced because Avista's ERM is the result of an agreement among the parties, and a company with far less favorable financial circumstances.

Second, Avista is far more susceptible to power cost risks than PacifiCorp, because "PacifiCorp is less reliant on hydroelectric power than Avista and PSE, which may suggest a differently structured PCAM."[44/]

Ironically, even though PacifiCorp has less need for a PCAM, and better ability to absorb power cost risks, the Company proposes a narrower deadband, and a less favorable sharing mechanism. While Avista's deadband is $4 million, the Company proposes only $3 million. Where Avista has a 50/50 sharing from $4 to $10 million, PacifiCorp proposes 60/40 from $3 to $7.4 million. In every respect, PacifiCorp's proposed PCAM is less adequate than Avista's ERM, even though a PCAM for PacifiCorp should be less favorable to shareholders than Avista's ERM.

Justification/Need for a PCAM

Q. HOW DOES THE COMPANY JUSTIFY ITS REQUEST FOR A PCAM?

A. The total Company justification for the PCAM amounts to one page in the testimony presented by Ms. Kelly[45/] and eight pages from Mr. Widmer.[46/] The Company supports the proposed PCAM as follows: 1) a PCAM is needed due to power cost volatility; and 2) other utilities in Washington have a PCAM. Neither witness presents any real evidence concerning the actual need for a PCAM.

Q. THE FIRST JUSTIFICATION FOR THE PCAM CONCERNS POWER COST VOLATILITY. PLEASE COMMENT.

A. The discussion in Mr. Widmer's testimony is very broad and general. There is no specific evidence presented to establish that the current level of power cost

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44/ WUTC Docket No. UE-050684, Order No. 04 at ¶ 93.
45/ Exhibit No.___(ALK-1T) at 11-12.
46/ Exh. No.___(MTW-1T) at 26-34.

volatility poses a serious problem for the Company. In fact, as discussed above, Mr. Widmer does not even present actual PACW data demonstrating that volatility is a problem. Instead, he relies on Exhibit No.___(MTW-4) which merely shows assumed cost impacts due to varying hydro levels. Again, the Company does not even claim to have actual PACW power costs, so there is no way of telling what its actual power cost volatility really is.

Even granting the existence of power cost volatility due to hydro variability, there is no explanation provided by either Ms. Kelly or Mr. Widmer as to why it is preferable to saddle ratepayers with power cost risks. A PCAM does not make the risk of power cost volatility go away. It merely allocates that risk to ratepayers instead of shareholders. It is not universally accepted that this is the most appropriate means of dealing with such risks. For example, in one of PacifiCorp's recent proceedings in Oregon, OPUC Staff witness Mr. Maury Galbraith recently testified against assigning such risks to ratepayers: "It is much more efficient to have the financial market diversify [Net Variable Power Cost] risk, than to allocate the risk to customers and have them bear it."[47/] As discussed above, in both Oregon and Utah, the Company has recently requested comprehensive PCAMs and then agreed to withdraw those requests as part of rate case settlements. At present, the Company has no comprehensive PCAM request pending in either state.

[47/] Re PacifiCorp, OPUC Docket No. UE 173, Exhibit Staff/100 at 7, 22-23 (Galbraith Direct).

Q. THE SECOND ARGUMENT ADVANCED IN SUPPORT OF THE PCAM IS THAT OTHER UTILITIES IN WASHINGTON HAVE ONE. PLEASE COMMENT.

A. While true, this seems more like the kind of argument one hears in relation to setting a child's weekly allowance than a well thought out justification. However, the Company failed to address some important facts. First, both the Avista and PSE PCAM mechanisms were initially adopted via settlement agreements among parties to 2001 rate cases of both companies. These PCAM mechanisms were adopted with the support of ratepayer representatives at the time and not over their objections. Second, both Avista and PSE were in serious financial difficulties when the PCAMs were first implemented. Indeed, the WUTC adopted those PCAMs as tools for restoring the financial health of both companies.[48/] At that time, PSE's bond rating was BBB by Standard & Poor's and Baa1 by Moody's with a negative outlook by both credit rating agencies[49/] and Avista had lost it investment grade status.[50/] PacifiCorp alleges no such financial hardship at this time, and there is no unanimous stipulation indicating support of other parties for its PCAM in this case. As a result, the comparison to Avista and PSE is simply unwarranted.

Q. CAN YOU PROVIDE ANY EVIDENCE THAT ADDRESSES THE ISSUE OF POWER COST VOLATILITY?

A. Yes. Exhibit No.___(RJF-10) shows results of my analysis of GRID model results, showing sensitivity of PacifiCorp's PACW power costs to changes in hydro levels, natural gas prices, coal prices, and wholesale market prices. This

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48/ WUTC v. Avista Corp., WUTC Docket No. UE-011595, Fifth Supp. Order at ¶ 6 (June 18, 2002).
49/ WUTC v. PSE, WUTC Docket No. UE-011570, Direct Testimony of Samuel Hadaway at 3.
50/ WUTC Docket No. UE-011595, Fifth Supp. Order at ¶ 7.

analysis illustrates that under current circumstances, the Company has very little sensitivity to any factor other than hydro generation.

Q. PLEASE EXPLAIN.

A. The analysis shows that a one standard deviation change in hydro generation levels results in an $8.6 million change in power costs to Washington, using the GRID and WCA models. This amounts to approximately 210 basis points for its ROE. While this is a moderate amount of sensitivity, it should occur, on average no more than once every three years. However, half the time, the hydro variance will be positive, meaning that only one in six years would the Company see a hydro deficit sufficient to cause a 210 basis point (or more) reduction in earnings. I believe hydro variations less than this amount should be absorbed by the Company.[51/] Given the Commission's comments in the final order in Docket No. UE-050684 indicating a PCAM should focus on short-term costs subject to market volatility, or other *extraordinary* events beyond the Company's control,[52/] I suggest the Commission agree.

Q. EXPLAIN YOUR CONCLUSIONS REGARDING THE SENSTIVITY OF PACIFICORP'S PACW POWER COSTS TO A 10% CHANGE IN NATURAL GAS AND COAL MARKET PRICES.

A. The exhibit shows a range equal to zero on the low end, and 10% of the annual expense on the high end. The results show a range of 0 to 68 basis points as the impact of a 10% increase in coal market prices, and 0 to 27 basis points for a 10% increase in gas market prices.

51/ The Public Utility Commission of Oregon relied on a standard of 250 basis points for setting the deadband in PacifiCorp's 2001 excess power cost case, Docket No. UM 995.

52/ WUTC Docket No. UE-050684, Order No. 04 at ¶ 99.

The Company purchases natural gas for Hermiston and coal for Bridger and Colstrip under long-term contracts. The Hermiston gas contract has shown little escalation and is far below current market prices. Likewise, coal prices are far more stable than overall power market prices or natural gas costs. Thus, I do not believe that the Company has any significant exposure to short-term market price variations for either gas or coal. These costs certainly do not fall into the category of costs that are beyond the Company's control. While the underlying costs may change as contracts expire or pricing terms change, there is no reason such costs cannot be addressed in a base rate case.

Q. ARE PACIFICORP'S PACW POWER COSTS SENSTIVE TO CHANGES IN WHOLESALE MARKET PRICES?

A. No. In fact, the two are *negatively* correlated, based on the GRID model runs I have performed. Because the Company tends to purchase in advance of its need, its short-term firm contract prices would not necessarily change if market prices changed. Based on the GRID model run, a 10% *increase* in balancing market prices alone results in a *decrease* in PACW net power costs equal to 21 basis points. If one assumes that all short-term (balancing and firm) prices *increase* by 10%, the Company would experience an 87 basis point *reduction* in costs.

Q. EXPLAIN THE IMPLICATIONS OF THIS NEGATIVE CORRELATION.

A. These results occur because the Company sells more power than it buys in PACW. Thus, the Company is well insulated from increases in market prices. It can even benefit from such price increases. Given this very low level of sensitivity to market prices, overall, I see no basis for considering wholesale market price volatility a problem for the Company.

Q. WHAT FACTORS WOULD CAUSE INCREASES IN PACW POWER COSTS?

A. The factors that can drive power costs to increase are the very items that neither the Commission, nor the Company, consider suitable for adjustment clause treatment. A one percent change in loads results in a 55 basis point change in cost. However, sales increases also result in increased margins for the Company offsetting the impact. As a result, the Company includes an adjustment in its PCAM to remove the impact of load changes. The Commission has recognized this issue in the Avista PCAM as well, and uses a comparable adjustment to reverse the impacts of load growth from the ERM. Load growth is far better addressed in a base rate case when new resources are required to serve that growth than in a PCAM.

Q. WHAT OTHER FACTORS DRIVE THE COMPANY'S POWER COSTS?

A. Other factors which would certainly impact power costs include new resources needed to address load growth or the expiration of existing contracts. For example, the expiration of the TransAlta contract in June 2007 will cause a $45 million increase (247 basis points) in PACW power costs according to the GRID model. Under the Company's PCAM proposal this will amount to a $5 million net increase to Washington, everything else being equal. If the Commission approves the PCAM, it really amounts to approving an additional $5 million automatic rate increase.

Again, the Commission has already stated new resources should not be part of the PCAM. Likewise, termination of a contract such as TransAlta should be considered in the context of a full rate case, to insure the Company has prudently planned for replacement power. A PCAM would automatically pass through market purchases as the sole source of replacement power.

Q. DO OUTAGES AFFECT PACIFICORP'S POWER COSTS?

A. As in the case of the Hunter outage in 2001, major plant outages could cause an increase in power costs on a temporary basis. However, it would be inappropriate to simply allow pass-through recovery of the cost of major outages without any review of the reasons for the outage or prudence of the associated costs. Again, even the Company recognized this by including a provision for major outages in its proposal.

Q. WHAT IS YOUR CONCLUSION REGARDING THIS SENSITIVITY ANALYSIS?

A. PacifiCorp does not need the PCAM it proposes because it does not suffer from substantial power cost variability. While various factors do impact the Company's power costs, in the end, the only factor driving PacifiCorp's power cost volatility that is arguably appropriate for a PCAM is hydro. I will address this issue next.

<u>Alternative PCAM</u>

Q. ASSUMING THE COMMISSION WISHES TO IMPLEMENT A MECHANISM TO ADDRESS THIS PROBLEM, DO YOU HAVE A PROPOSAL?

A. Yes. In that case, I would recommend implementation of a "Hydro Hedge PCAM" to simulate a hypothetical hedge agreement between PacifiCorp and its Washington ratepayers. The concept is that ratepayers would be the counterparty to a hedge (much like the Aquila hedge the Company used in prior years).

Under this proposal, ratepayers would compensate the Company for a specific dollar amount in the event of poor hydro conditions. The hedge would only be implemented when power costs departed from normal or average conditions by more than one standard deviation from the mean. This approach would be consistent with the "filtered water" methodology discussed above in the power cost modeling section of this testimony.

However, if the Commission adopts this proposal, I recommend that the Commission require the Company to pay ratepayers a "premium" for being the counter party in this hedge with the Company. The level of the premium should equal the reduction to PacifiCorp's overall cost of capital that occurs as a result of implementing this PCAM. Mr. Gorman has estimated this amount to be $1.2 million based on PacifiCorp's current return on equity.

Q. IS A PREMIUM OF THIS SORT A REASONABLE FEATURE OF THIS HYPOTHETICAL "HYDRO HEDGE" TARIFF?

A. Certainly. PacifiCorp would normally expect to pay a counterparty to enter into such a hedge. For example, PacifiCorp paid Aquila $1.75 million per year as a premium to enter into a hydro hedge over the past several years. I see no reason why ratepayers should assume the risks of a hedge arrangement but not be afforded a fair premium for doing so. Further, the level of the proposed premium is consistent with the Commission's order in Docket No. UE-050684.[53/]

[53/] "Ratepayers should receive the benefit of a reduction in cost of capital, as a power cost adjustment introduces rate instability for ratepayers and earnings stability for stockholders[.]" WUTC Docket No. UE-050684, Order No. 04 at ¶ 91.

Q. ARE THERE ANY OTHER ADVANTAGES OF THIS PROPOSAL?

A. Yes. This proposal would not require determination of PacifiCorp's actual PACW power costs. It would deal only with the Washington share of the variances due to hydro costs. These would be allocated to the State on the basis of the CAEW factor. Thus, it sidesteps the jurisdictional allocation problem and deals only with normalized costs, rather than hypothetical actual costs.

Further, it is far more tractable to analyze the impact of a change in cost due to hydro, the issue of PACW costs, overall. Recall that in Docket No. UE-050684, the Commission determined it was possible to develop a deferral for PacifiCorp's hydro deficit. The same concept would be applied here, except that GRID runs would be used to develop an *a priori* allocation of hydro cost variances.

Q. DESCRIBE THE STATISTICAL ANALYSIS OF PACIFICORP'S HYDRO GENERATION AND POWER COSTS YOU HAVE PERFORMED TO ILLUSTRATE THE WORKINGS OF THE HYDRO HEDGE TARIFF.

A. Exhibit No.___(RJF-11) shows the analysis underlying the Hydro Hedge PCAM. The proposed Hydro Hedge PCAM would not result in any payments of credits (other than the premium) if the hydro costs impact was less than one standard deviation from the mean. The proposal would then use a sharing of 50/50 between the Company and customers for variations less than two standard deviations, and 85/15 customer/company beyond that. The exhibit shows the payments and credits that would result depending on the actual annual level of hydro generation.

Q. WHAT ARE THE ADVANTAGES OF THIS APPROACH?

A. First, it addresses only costs that are not controllable by the company, related to short-term weather variations. This was one of the guiding principles espoused by the Commission in the Docket No. UE-050684. This approach defines up front the level of risks assumed by customers and limits them to a known amount. Risks are limited to hydro variations, which we all agree are beyond PacifiCorp's control. Under the Company's proposed PCAM, there is virtually no limit to the amount and scope of risk that ratepayers assume. I believe it is very unlikely that PacifiCorp could find a counterparty that would hedge unlimited risks and risks of virtually any kind. Ratepayers should not be required to provide a hedge completely out of line with what is available in the commercial market.

Second, this approach is equitable because it provides a known treatment of hydro cost variations, consistent with the use of the filtered water approach for setting base rates. Third, by use of the sharing bands indicated, the Company will retain incentives to minimize costs, and costs placed on ratepayers will be limited. Finally, ratepayers are not exposed to unlimited cost increases in the case of extremely bad hydro conditions, nor is the Company exposed to unlimited refunds in the case of extremely good hydro conditions.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.