Exhibit No.___(RJF-1T)
Docket Nos. UE-050684/UE-050412
Witness: Randall J. Falkenberg

**BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

| | | |
|---|---|---|
| WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, | ) | |
| Complainant, | ) | **Docket No. UE-050684** |
| vs. | ) | **Docket No. UE-050412** |
| PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY | ) | *(consolidated)* |
| Respondent. | ) | |

**DIRECT TESTIMONY OF RANDALL J. FALKENBERG**

**ON BEHALF OF**

**THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES**

**REDACTED VERSION**

**(Confidential Information Removed and Empty Spaces Blacked Out)**

**November 3, 2005**

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

**A.** Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Sandy Springs, GA 30350.

**Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

**A.** I am a utility rate and planning consultant holding the position of President and Principal with the firm of RFI Consulting, Inc. ("RFI"). I am appearing in this proceeding as a witness for the Industrial Customers of Northwest Utilities ("ICNU"). My qualifications are 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 GRID model study of normalized net power costs for the pro-forma period, April 2006 to March 2007. I identify a serious problem in the GRID study that overstates the Company's revenue requirement. I also address the Company's Revised Protocol, the Power Cost Adjustment Mechanism ("PCAM"), and one other revenue requirements issue.

**Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

**A.** Table 1 summarizes my recommended test year net power costs and other revenue requirements adjustments. My major findings are as follows:

**1. PacifiCorp's request for $830.3 million in (Total Company) net power costs is substantially overstated. I recommend the Commission adopt the Stipulation Net Power Cost adjustment and one additional power cost adjustment, resulting in a reduction to Washington net power costs. Table 1, below, summarizes the impact of my proposed adjustments.**

**<u>Production Factor Adjustment</u>**

**2. PacifiCorp's use of projected Fiscal Year ("FY") 2007 loads and a production factor adjustment should be rejected by the Commission. This treatment serves to transfer costs of prospective growth from other states to Washington, has not been accepted in other states, and is inconsistent with the Revised Protocol. I recommend use of historical test year (September 30, 2004) loads in GRID, reducing net power costs by the amount shown on Table 1.**

**<u>Multi-State Process Adjustments</u>**

**3. The Commission should either develop an allocation methodology based on the costs of the pre-merger Pacific Power and Light ("PP&L") system, or make certain changes to the test year and place conditions on its approval of the Revised Protocol. In this testimony, I present both alternatives.**

**4. If the Commission chooses to base its jurisdictional allocation on the capacity mix of the pre-merger PP&L system, I propose a "Pre Merger-ECD" credit to implement that approach. This methodology uses many elements of the Revised Protocol, but modifies the PacifiCorp Embedded Cost Differential ("ECD") factor to fully capture the lower costs pre-merger PP&L system.**

**5. If the Commission wishes to adopt the Revised Protocol, I propose certain corrections to the Company filing, and recommend conditions that the Commission should place on its approval of the document.**

**6. Mr. Duvall contends his "growth studies" show that the Revised Protocol does not result in cost shifting from Utah to Washington. These studies rely on the assumption that costs of new plants added to meet Utah load growth are offset by increases in Utah's allocation overall factors. However, the test year in this case uses historical loads for determination of the allocation factor, but includes the costs of future plants built to meet Utah load growth. Thus, the assumed linkage between reduced allocation factors and higher new plant costs is broken. To address this problem, the cost of the new Currant Creek plant should be removed from the test year and only included when it is operational in a historical test year. At that time, issues related to prudence and the used and useful**

**standard should be addressed. Table 1 shows the impact of removing Currant Creek from the test year.**

7. **The application of the production factor also serves to reduce the value of the Revised Protocol ECD credits applied to Washington. Reversing the production factor reduces the Washington revenue requirement by the amount shown on Table 1.**

8. **The Revised Protocol requires situs allocation of "Existing QF Contract" costs in excess of embedded cost. Existing Qualifying Facility ("QF") Contracts are those in effect prior to the effective date of the Revised Protocol. The Revised Protocol document indicates the effective date for a state is the date of Commission approval. For Washington the effective date will not occur until the final order in this case. Four QF contracts (Desert Power, US Magnesium, Kennecott and Tesoro) were negotiated and executed prior to the filing of this case. For these contracts expenses in excess of embedded costs should be allocated situs, rather than on a system basis. Correcting this problem results in a reduction to Washington revenue requirements by the amount shown on Table 1.**

**<u>PCAM Proposal</u>**

9. **The Commission should reject the proposed PCAM. 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 the PCAM concept.**

10. **PacifiCorp's PCAM will complicate the regulatory process. It would create the need for additional audits to verify actual power costs. Before allowing a permanent PCAM, the Commission should first hold a rulemaking or a generic investigation proceeding to develop proper rules, procedures, filing requirements, and incentive mechanisms.**

11. **There are several serious design flaws in the proposed PCAM. The proposed PCAM is needlessly complex and inconsistent with the Revised Protocol. A major defect in the proposed PCAM is that it will shift costs from faster growing states to Washington. There is no dead band, and the sharing mechanism is not consistent with PacifiCorp's PCAM proposal in Oregon.**

**<u>Non-Power Cost Adjustments</u>**

12. **PacifiCorp has an eighty-year contract to provide the Western Area Power Administration ("WAPA") transmission service. Regulators in both Oregon and Utah have made imprudence disallowances related to**

**this contract because it lacks any price escalation provisions. I recommend a similar disallowance.**

**Table 1**
**Summary of Recommended Adjustments**
**$1000**

| | Total Company | Washington Jurisdiction |
|---|---|---|
| | | SE 8.434% |
| Reference: | | SG 8.627% |
| **I. MSP Issues** | | |
| **Option 1: Pre Merger ECD** | $0 | -$8,604,686 |
| 1 Pre Merger ECD Credit | $0 | -$8,604,686 |
| **Option 2: Corrections to Revised Protocol** | -$38,130,443 | -$5,703,538 |
| 2 Remove Currant Creek from Test Year | -$38,130,443 | -$3,227,880 |
| 3 Situs QF Contracts | $0 | -$1,698,403 |
| 4 Reverse Production Factor Adj.- ECD | $0 | -$777,256 |
| **II. GRID (Net Power Cost Issues)** | | |
| 5 PacifiCorp NPC (With Prod. Factor) | $830,333,138 | $70,769,019 |
| **A. Power Cost Adjustments** | -$31,500,000 | -$2,687,108 |
| 6 Stipulated Adjustment | -$31,500,000 | -$2,687,108 |
| **B. Reserved Power Cost Issues** | | |
| 7 Reverse Production Factor | -$113,864,419 | -$9,823,083 |
| **Total Power Cost Adjustments -** | -$145,364,419 | -$12,510,191 |
| **Allowed NPC - Final GRID Result** | $684,968,719 | $58,258,828 |
| **Other Adjustments** | -$2,786,405 | -$240,383 |
| 8 WAPA Revenue | -$2,786,405 | -$240,383 |
| **Total All Adjustments - Option 1** | -$145,364,419 | -$21,114,877 |
| **Total All Adjustments - Option 2** | -$186,281,267 | -$18,454,113 |

## II. NET POWER COST ISSUES

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

**A.** Net power costs ("NPC") are the variable production costs related to fuel and purchased power expenses, net of power sales revenue. Power costs comprise a substantial portion of the overall revenue requirement, and thus, are a significant component of PacifiCorp's proposed base rates. In Docket No. UE-032065, the Stipulation allowed the Company $534 million in (Total Company) net power costs. In this case, the Company is requesting $830 million (Total Company). Based on the proposed allocation factors, this $296 million increase in system level power costs is responsible for approximately $25 million in increased revenue requirements for Washington, or more than 60% of the requested increase of $39 million. One issue, the production factor adjustment, is responsible for $9.8 million in Washington revenue requirements, or about 25% of the entire increase.

**Q. DESCRIBE THE PROCESS LEADING UP TO THE NET POWER COST STIPULATION.**

**A.** ICNU completed its analysis of the Washington GRID study in time for the September 23, 2005 Settlement meetings. At that time, ICNU had identified a substantial number of issues and adjustments. In many cases these adjustments were issues that had been litigated, or settled, in other jurisdictions. However, there were also a number of new issues unique to this case. Though the September settlement meetings did not lead to a settlement of the issues in this case, all parties agreed that ICNU and PacifiCorp should continue discussions regarding ICNU's power cost issues. Eventually ICNU and PacifiCorp agreed on a Net Power Cost Stipulation, which has been filed in this case.

**Q. DESCRIBE THE NET POWER COST STIPULATION.**

**A.** ICNU and the Company have agreed to a Stipulation concerning system wide power costs. The Stipulation calls for a total reduction to net power cost of $31.5 million on a total Company basis, prior to application of PacifiCorp's proposed production factor adjustment. ICNU has reserved the right to litigate the production factor issue in the Stipulation. If the Commission adopts a production factor adjustment, the net power cost reduction will be multiplied by the approved production factor. This is a reasonable treatment because ICNU's proposed power cost adjustments were computed prior to application of the production factor.

ICNU and the Company have also agreed that $5.2 million of the $31.5 million Total Company reduction was related to issues concerning the Sacramento Municipal Utility District ("SMUD") contract (after it was repriced at $37/megawatt hour ("MWh") in GRID) and the IMC/Kalium contract. In the event that the PacifiCorp PCAM is approved, the Company agrees to make conforming adjustments to the actual net power costs used in the PCAM.

Finally, the Company and ICNU have agreed that if the Revised Protocol methodology is not adopted, but instead an interjurisdictional allocation method that assigns only western resources to Washington (such as proposed by Staff in UE-032065), then the NPC adjustment will be reduced by 50%. This is also reasonable because western resources adjustments amount to roughly half of the adjustments in ICNU's analysis of power costs.

**Q. DOES THE STIPULATION RESOLVE ALL NET POWER COST ISSUES?**

**A.** All NPC issues except the production factor issue are resolved in the Stipulation. Under the terms of the Stipulation, neither PacifiCorp nor ICNU will sponsor any other adjustments, and will not cross examine each other concerning net power cost issues other than the production factor issue. ICNU is not submitting testimony on any power cost issues that may be raised by other parties. However, the Stipulation does not prevent ICNU from advocating that PacifiCorp remove the costs of any specific resources from PacifiCorp's rate base or revenue requirement. I believe this Stipulation is a fair and reasonable resolution of ICNU's power cost issues in this case, and I recommend the Commission adopt the Stipulation.

### 1. <u>Production Factor Adjustment</u>

**Q. EXPLAIN THE PROPOSED PRODUCTION FACTOR ADJUSTMENT.**

**A.** In this case, the Company proposes to use a historical test year of September 30, 2004, for many rate base, revenues, expense, billing unit, and allocation factor inputs. However, for net variable power costs the Company proposes to use a fully projected March 31, 2007 test year. Because the system level loads for FY 2007 are projected to grow by 7.24% over test year levels, the Company scales back the GRID model results by 92.8% to conform the FY 2007 power costs to historical test year (September 30, 2004) load levels. This adjustment reduces net power costs from the GRID model Total Company NPC result of $895.2 million to $830.3 million reflected in the filing. This is called the “production factor” adjustment.

**Q. HAS THE COMPANY USED THIS APPROACH IN PRIOR CASES?**

**A.** No. The Company did not use the method in UE-991832 or UE-032065. To my knowledge the Company has only proposed this methodology in one prior case in the past six years, in Oregon Public Utility Commission (“OPUC”) Docket No. UE 134. While that case was settled, the Company did not end up using the production factor methodology in establishing rates, and it has not been applied in any subsequent Oregon proceedings.[1/]

**Q. EXPLAIN IN MORE DETAIL HOW PACIFICORP HAS MODELED POWER COSTS IN OTHER CASES.**

**A.** In recent Washington cases, the Company has primarily used a historical test year. For power costs, however, the Company has reflected “known and measurable changes” for a “pro-forma period” that extends beyond the test year. For example, in UE-032065, the Company used a March 31, 2003 test year, but for power cost purposes it reflected known and measurable changes to March 31, 2004. This method has been commonly applied in recent cases in Wyoming and Utah as well. In Oregon, however, the Company has used a fully projected test year for recent proceedings.

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1/ While this issue was not discussed in the settlement document in that case, at the time PacifiCorp was operating under a Bridge Agreement which adjusted for differences between actual and normalized power costs. The normalized power costs used in the Bridge period did not reflect any production factor adjustment.

**Q. DO YOU AGREE WITH THE APPROACH USED BY THE COMPANY?**

**A.** No, for three major reasons. First, the proposed methodology creates a mismatch between the loads used to compute power costs, and the load data used for all other revenues, expenses and allocation factors.

Second, the production factor methodology is not technically sound. While attempting to correct the mismatch problem with the Production Factor, the Company computed the impact of reducing loads to test year levels using the average net power cost ($15.6/MWh). This is clearly inappropriate, as changes in load result in changes in market purchases, which would be priced at the incremental, not average, cost of power. As a result, the Company has substantially understated the impact of conforming the loads to test year levels.

Finally, I will demonstrate in detail that the production factor methodology transfers the cost of prospective load growth from rapidly growing states (such as Utah) to slower growing states, such as Washington, and that this problem would be exacerbated if the proposed PCAM methodology is adopted.

**Q. HOW DOES THE COMPANY JUSTIFY ITS USE OF THE PRODUCTION FACTOR METHOD?**

**A.** The Company does not contend the method is appropriate or even correct in any technical sense. Instead, Mr. Widmer merely states that the approach is consistent with the methodology used by Puget Sound Energy ("PSE").[2/]

**Q. PLEASE COMMENT.**

**A.** There are several problems with this justification. First, the Company has not justified its use of a projected test year for power costs while using a historical

[2/] Exhibit No.___(MTW-1T) at 5.

test year for allocation factors and other elements of cost. Loads are expected to grow over the months ahead, and increased loads will result in increases in revenue. However, in the Company's test year, the billing units for base rates are based on historical levels. Also, the jurisdictional allocation factors proposed by the Company are based on the historical loads. Given the disparity in growth among the states, load growth should equate to reduced allocations to Washington and higher billing units, resulting in a lower cost on a per kilowatt hour ("kWh") basis. Unless the Commission wishes to examine all of the impacts of load growth (properly matching revenues, expenses, and allocations), it should not allow a blend of historical and projected test years.

Second, the reliance on practice in PSE cases is misplaced. It appears that in the case of PSE, the use of post test year loads in the power cost study (giving rise to use of the production factor) does not have as substantial an impact on overall revenue requirements. There is evidence that the impact of this issue has been, and is now, much less significant for PSE than for PacifiCorp. Further, PSE only operates in the state of Washington.

In PSE's 2004 case, the total level of the production factor was 98.7% (or a reduction to power costs of 1.3%).[3/] In contrast, PacifiCorp's proposed production factor is 92.8% and the power cost impact is 7.2%, more than five times the PSE value. While the production factor methodology may not make a substantial impact when load growth is small, it can make a substantial impact

[3/] Re PSE, WUTC Docket Nos. UG-040640, UE-040641, UE-031471, and UE-032043, Initial Brief of PSE at 46-47 (Jan. 18, 2005).

when load growth is large.[4] PacifiCorp's load growth is relatively large (for states other than Washington), thus, this issue is much more significant for PacifiCorp. Given the significance of this issue in the present case, it would be wise for the Commission to examine it carefully before applying it to PacifiCorp. If the Commission decides to apply the production factor adjustment, the problems identified in my testimony must be corrected in some other way.

**Q. EXPLAIN IN MORE DETAIL WHY PACIFICORP'S STATUS AS A MULTI-STATE UTILITY IS SO IMPORTANT.**

**A.** The first reason is that the jurisdictional allocation factors have all been computed in this case on the basis of historical loads. Consequently, Washington's share of system costs is based on its historical share of system load. Because Washington is a slow growing state, its allocation factor for the September 30, 2004 historical test year will be higher than it would have been had a fully projected FY 2007 test been used. As a result, Washington will be assigned higher allocation factors than would be appropriate given the power costs used in the test years. This is a serious problem in the context of the Revised Protocol methodology proposed by the Company.

**Q. PLEASE EXPLAIN FURTHER.**

**A.** Revised Protocol is a "Rolled-in" allocation method. The criticism of this approach is that the load growth costs of faster growing states are shifted to slower growing states, because all states share in system costs. However, the Company has always contended that under Revised Protocol, the increases in resource costs from the faster growing states are offset by the reduction to the

[4] Particularly when the load growth comes from other states.

allocation factors of slower growing states. This is discussed in the Direct Testimony of Mr. Duvall:

> Q. Why aren't more of the costs of the additional Resource passed on to other States?
>
> A. While all States pick up their proportional share of the higher than system average costs of the New Resource, Utah - the faster growing State in this example - picks up a larger share of all other allocated costs. As a result of its now larger allocation factors, Utah picks up a larger share of the costs of the remaining generation Resources, a larger share of the system's transmission costs, a larger share of A&G expenses, and all other allocated costs.[5/]

In the production factor methodology, however, ratepayers in Washington will still be assigned much of the cost of growth, but in this case, without that offsetting reduction to their allocation factors. As a result, Revised Protocol fails to provide the protection from the costs of growth ascribed to it by the Company when applied in the context of the production factor methodology.

**Q. CAN YOU DEMONSTRATE THAT THIS PROBLEM EXISTS IN THE TEST YEAR?**

**A.** Yes. Exhibit No.___(RJF-3) presents historical and projected load data by state and illustrates this problem. From the Exhibit one can see that Washington is a low growth state. From FY 2000 to September 30, 2004, Washington's average energy load actually declined. During the same period, Utah's growth amounted to 140% of the system total, because other states' loads declined by less than Utah's loads grew.

The Company projects this pattern of disproportionate growth to continue. From the September 30, 2004 historical test year to FY 2007, system load growth

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5/ Exhibit No.___(GND-1T) at 18.

is expected to be 8.2%, or 4,334,786 MWh.[6/] For the period from FY 2000 to FY 2007, total growth is projected to be over 11%. Utah is projected to be responsible for 83% of overall load growth, while Washington is responsible for only 1%. In total, Washington sales growth from 2000 to 2007 is expected to be virtually zero.

**Q. WHAT IS THE VARIABLE POWER COST ASSOCIATED WITH THIS GROWTH FROM THE HISTORICAL TEST YEAR TO FY 2007?**

**A.** Based on GRID studies, the additional costs due to growth amount to $178.7 million on a Total Company basis.[7/] Because PacifiCorp "scales back" the power cost model result by the Production Factor (92.8%), "only" $113.8 million of this additional cost is used in the test year. This additional cost is assigned to Washington on the basis of the Rolled-in allocation factor (8.5%). Thus, Washington would be assigned $9.7 million of the cost of this prospective growth. However, these costs include the impact of all states (including Washington's) load growth. Nonetheless, because Utah is the high growth state, some of its growth costs are being shifted to slower growing states such as Washington.

**Q. CAN YOU MEASURE HOW MUCH COST OF UTAH'S GROWTH IS BEING SHIFTED TO WASHINGTON UNDER THE PRODUCTION FACTOR METHODOLOGY?**

**A.** Yes. The Company has developed a methodology to measure cost shifting. While I do not fully endorse this approach, I use it here for purposes of

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6/ These figures, based on the workpapers used to develop the test year allocation factors, differ from those used by the Company in developing its production factor. There is no explanation for this discrepancy in the Company workpapers or the discovery. This indicates the Company may have understated its production factor adjustment. If the Commission does not reject the production factor methodology, it should investigate this issue and determine the correct figure to use.

7/ This information was provided in PacifiCorp's response to ICNU data request ("DR") No. 9.3a.

illustration.[8/] Under the PacifiCorp method, costs are compared in two scenarios. In the first scenario, costs are based on the total projected growth of all states. In the second scenario, the growth rate for the high growth state is reduced to match the average growth rate of the remaining states. The difference in costs between the two studies, as allocated to each state, represents the cost shifting from the growth state to the slower growing states.

**Q. WHAT ARE THE RESULTS OF THIS ANALYSIS?**

**A.** This is also shown on Exhibit No.___(RJF-3). The exhibit shows that Total Company projected FY 2007 power costs would be $895.2 million. If Utah's load grew at the average rate of all other states, total Company FY 2007 net power costs would be $819.2 million. Thus, Utah's excess load growth costs amount to $76 million.

**Q. HOW MUCH OF THIS COST WOULD BE ASSIGNED TO WASHINGTON, UNDER THE PRODUCTION FACTOR METHODOLOGY?**

**A.** Under the production factor methodology, Total Company net power costs allocated to the states would be $830.3 million. Based on Washington's allocation factor, it would be assigned approximately $70.03 million in total net power costs. If Utah's loads grew at the average rate of other states, Washington would be assigned $65.86 million. Thus, use of the production factor methodology (as a means of "scaling back" projected loads to test year levels) would result in Washington being assigned $4.1 million in costs related to Utah's load growth beyond the end of the test year.

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8/ Later I will discuss my criticisms of the methodology, which have more to do with its failure to address prior growth and plants under construction.

Ironically, Washington may be the only state where such excess growth costs are actually charged to ratepayers without any mitigation resulting from reduced allocation factors. Because the other states have used either fully projected or historical test years without the production factor adjustment, the mismatch between allocation factors and loads creating this issue does not arise for the other states.

However, this is not the end of the story. If PacifiCorp's PCAM proposal is adopted, Washington would be allocated 90% of the additional costs of growth that were not already allocated under the Production Factor methodology. In fact, the PCAM would assign Washington an additional $4.9 million in Utah growth related costs, for a total of $9.0 million. Even assuming Utah used the production factor method and had the same PCAM, it would be assigned only $43 million of its $76 million in growth costs. However, Utah does not presently have a PCAM, and as yet, the Company has not proposed one in that state. Without a PCAM comparable to that proposed in Washington, Utah would be assigned less than $20 million of its excess growth costs. Considering Utah's total cost of excess growth is nearly $76 million, this approach is highly inequitable.

**Q. DO THESE CIRCUMSTANCES DIFFERENTIATE PACIFICORP FROM PSE?**

**A.** Yes. This is a problem present in a multi-state utility like PacifiCorp that does not exist for a single state utility like PSE. Note also that this is a problem that is not rectified by use of the Revised Protocol, as the Company might claim. As discussed above, the increase in costs due to faster growing states is not offset by reduced allocations to Washington when allocation factors are based on historical loads, while power costs are based on prospective loads.

**Q. COULD THIS PROBLEM BE SOLVED BY UPDATING THE ALLOCATION FACTORS TO REFLECT FY 2007 LOADS?**

**A.** No. At most that would address a part of the problem. However, if FY 2007 loads are used, then also there should be an increase to Washington test year revenues and billing units, resulting in a lower net cost per kWh. In the end, the Company should use either a fully projected or historical test year, but it should not "mix and match" test years. Further, it would be highly inequitable to allow the Company to present a new FY 2007 test year in its rebuttal case, as parties would have no opportunity to conduct discovery to respond to what would amount to a totally new rate filing.

**Q. ARE THERE ANY OTHER INCONSISTENCIES WITH RESPECT TO THE USE OF THE PRODUCTION FACTOR METHOD AND THE REVISED PROTOCOL?**

**A.** Yes. The production factor method has never been applied in conjunction with Revised Protocol in any other state. None of the equations defining the allocation factors used in the Revised Protocol reference any production factor adjustment.[9/] Consequently, it is fair to say that the production factor methodology is not even contemplated by the Revised Protocol. It really would amount to an ad-hoc adjustment to Revised Protocol for Washington only.

Further, the Revised Protocol features an ECD calculation that credits Washington (and other western states) for the lower cost of hydro facilities on the system. In the calculation of the ECD in other states, the Company has never

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9/ Exhibit No.___(DLT-2) at 45-62.

made a production factor adjustment. This is a particular problem because the ECD contains both fixed and variable costs. Thus, the Company applied the production factor to some elements of cost in the ECD, but not others. For example, credits for the situs allocation of QF costs have been reduced by the Production Factor, while the Mid-C credit has been increased. These adjustments make no sense because the QF and Mid-C costs do not depend on the level of PacifiCorp's loads during the test year. Ultimately, the application of the production factor to the ECD calculation decreases the value of these credits to Washington by $0.78 million.[10/] This is significant because these credits are a key element of the benefits for Washington which PacifiCorp projects to exist under the Revised Protocol. If these benefits are reduced, then PacifiCorp's savings projections are in doubt.

Finally, it should not be lost on the Commission that there remains a dispute among the states as to the proper treatment of growth costs under the Revised Protocol. The Revised Protocol was adopted in Oregon and Utah without resolving how to address the problem of cost shifting caused by load growth. While PacifiCorp has held numerous meetings to discuss the problems, no solution has been reached. It could prove advantageous for high growth states such as Utah to adopt the production factor methodology, as a means of shielding itself from some of its growth costs. If the WUTC were to adopt the method for Washington, in this case, it might be used as an argument for Utah to do the same in its next rate case, thus, perpetuating this inequitable arrangement.

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10/ Exhibit No.___(DLT-6); PacifiCorp's response to ICNU DR No. 9.3b.

**Q. ARE THERE OTHER PROBLEMS THAT RESULT FROM THE USE OF PROSPECTIVE LOADS IN THE POWER COST STUDY?**

**A.** Yes. In the most recent Utah case, the Utah Division of Public Utilities ("DPU") presented testimony challenging the Company's forecast of Utah load growth. The DPU even proposed an adjustment of $28.5 million on a total Company basis based on reducing the Utah load growth forecast.[11/] Ultimately, the Utah case was settled, so there is no clear indication of whether that adjustment would have been accepted by the Utah Commission. However, if the WUTC allows PacifiCorp to use a partially projected test year, it should carefully consider whether the load forecast is correct, particularly the load forecast used for Utah as the costs of Utah's growth are being transferred to Washington.

**Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?**

**A.** I recommend that the Commission require the Company to use loads for the power cost study based on the September 30, 2004 historical test year, as opposed to the projected FY 2007 loads. Applying this adjustment reduces power costs by the amounts shown in Table 1.

## III. MULTI-STATE PROCESS

### 1. Background

**Q. BRIEFLY EXPLAIN WHAT THE MULTI-STATE PROCESS ("MSP") CONCERNS.**

**A.** The multi-state process concerns the allocation of the costs of resources among PacifiCorp's six states. This problem originated with the PP&L-Utah Power &

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11/ Exhibit No.___(RJF-11) at 3 (Direct Testimony of Andrea Coon, Utah Division of Public Utilities, Utah Public Service Commission ("UPSC") Docket No. 04-035-42).

Light ("UP&L") merger and for Washington remains an unresolved problem. Mr. Duvall discusses these issues extensively in his testimony.

**Q. THE PP&L–UP&L MERGER WAS APPROVED BY THE WASHINGTON COMMISSION IN 1988. WHY, AFTER 17 YEARS, IS THE ISSUE OF A JURISDICTIONAL ALLOCATION METHODOLOGY STILL A PROBLEM?**

**A.** This is a fairly common problem for multi-state utilities. In cases where there is a "system agreement"[12/] such issues are resolved by the Federal Energy Regulatory Commission ("FERC"). Because PacifiCorp has no system agreement, FERC is not involved. However, FERC regulation of such agreements has frequently been a source of bitter controversy and FERC moves very slowly in addressing such issues. Also, when mergers have occurred, there can be lingering problems in resolving such issues when noticeable cost differences existed between the pre-merger companies.

In the case of PacifiCorp, the problem can be traced back to decisions made by PP&L and UP&L at the time of the merger. It now appears that the applicants were simply too anxious to gain approval of the merger to take the time necessary to 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 <u>after</u> approval of the merger was obtained.[13/] The Washington Commission was clearly concerned about the potential problems stemming from the combination of the two systems:

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12/ This is a contract that specifies the allocation of costs and resources among operating units in multi-state utilities. Examples include Southern Company, Entergy, and AEP. Because such agreements generally control wholesale transactions, FERC regulates them.

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

> 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.[14/]

The reference to "Pacific's" average system cost is significant, as it indicates that from that time, until there was a resolution of this issue, the Commission was inclined to use the average power supply cost of the pre-merger PP&L as the basis for determining rates. It appears this was the "norm" expected to be followed until a new allocation method was agreed upon. A comparable passage is found in the Order of the Oregon Commission approving the merger.[15/]

Consequently, it is well established that the differences in system costs was a concern of the Washington and Oregon Commissions from the start. However, it seems clear that the applicants were rather unconcerned with this problem. In fact, the applicants represented to various Commissions that shareholders would assume the risk of any failure to achieve a consensus concerning jurisdictional allocation.[16/]

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[14/] Id. at 14.

[15/] "Second, the stipulation provides that pre-merger generation and transmission facilities of Pacific and Utah Power shall remain the responsibility of the Pacific and Utah divisions, respectively. This will ensure that the higher cost facilities located in Utah will not have a negative impact on Oregon ratepayers. If necessary, the Commission has the authority to require the continued segregation of the Utah Power rate base from the Pacific Power rate base beyond the term of the stipulation. Likewise, the determination of variable power costs by use of stand-alone and merged-operation simulations and the allocation of net merger benefits could be continued beyond the five-year period." Re PP&L, OPUC Docket No. UF 4000, Order No. 88-767 at 22 (July 15, 1988).

[16/] Id.; Re PacifiCorp, UPSC Docket No. 87-035-27, Order at 62-64 (Sept. 28, 1988).

While the Company has recently claimed to be "gravely concerned"[17/] with this problem, its roots lie in the fact that there was apparently insufficient concern about it when the merger was first proposed.

**Q. ARE THERE ANY OTHER IMPLICATIONS OF PACIFICORP'S ASSUMPTION OF RISK THE COMMISSION SHOULD CONSIDER?**

**A.** Certainly. When ScottishPower acquired PacifiCorp, it should have been aware of this potential problem. Proper "due diligence" should have identified all of the risks faced by PacifiCorp that ScottishPower would be assuming. Therefore, the Commission should view ScottishPower as assuming the liability related to the assumption of risk of any failure to achieve consensus in jurisdictional allocation. Similar comments would apply in the latest proposed purchase of PacifiCorp by MidAmerican.

**Q. WHAT MAKES THIS PROBLEM SO INTRACTABLE?**

**A.** First, resolution of the problem requires an agreement by all six states. It appears that there has never been a permanent "meeting of the minds" regarding this problem and difficult new issues have emerged over time. Originally, the prime concern was the manner to treat cost differences between the PP&L and UP&L systems. As shown by the quote from the merger approval order, above, the major issue was the presence of low-cost resources on the PP&L system. Utah parties generally sought to eventually merge all of the costs of the system ("Rolled-in") and obtain a share of this benefit. Oregon and Washington parties preferred to preserve this benefit for the customers in the Northwest.

[17/] Re PacifiCorp, OPUC Docket No. UM 1050, Suppl. Direct Testimony of Andrea Kelly at 12 (May 21, 2004).

Recently, the eastern control area shortfall and the disparity in growth among the states have led to the emergence of a new issue: cost shifting. Like the hydro issue, this has proven to be beyond resolution. Cost shifting is the result of a disparity in growth rates among these states.

There have been temporary solutions—first the "Accord" method, then the "Modified Accord" methodology, and, in the past few years, the "Original Protocol" and "Revised Protocol" methodologies. The Original Protocol was never adopted by any state, but it was used to determine Washington revenue requirements last year pursuant to a Commission order adopting a Stipulation entered into between Staff and the Company. Giving Washington customers Original Protocol was the worst of all possible outcomes. The Revised Protocol is the new methodology that grew out of the process initiated after Utah's break from the Modified Accord method.

In 1997 the Utah Commission made a unilateral decision to reject the previously adopted Modified Accord methodology in favor of its preferred Rolled-in methodology. This led PacifiCorp to propose a variety of solutions, including the balkanization of the system in the "Structural Realignment Proposal." As this would have led to the diminution of state regulation vis-à-vis FERC regulation, it was short-lived. After years of negotiation, the Company and four states (Idaho, Oregon, Utah, and Wyoming) have now settled on the Revised Protocol "compromise" solution. The Company now proposes that the Revised Protocol be used in this and future cases for Washington.

**Q. WHAT ARE THE MOST SIGNIFICANT PROBLEMS WITH THE REVISED PROTOCOL?**

**A.** There are several serious issues that are not resolved in the document:

1. The proposed Hydro Endowment and Mid-C allocation do not provide substantial benefits to Pacific Division customers. While Pacific Division customers are assigned 100% of the costs of the Western System hydro and Mid-C, they receive only a small portion of the benefits.

2. There is no structural protection vis-à-vis the issue of cost shifting or unequal load growth among the states. Further, PacifiCorp's implementation of the Revised Protocol in this case exacerbates the problem of cost shifting.

3. PacifiCorp has entered into rate caps with two other states that could potentially result in unfavorable outcomes for Washington.

4. It remains to be seen if the MSP Standing Committee will be an effective tool for addressing future disagreements.

**Q. EXPLAIN WHAT YOU MEAN BY THE TERM "HYDRO ENDOWMENT."**

**A.** This refers to a preferential allocation of PacifiCorp's owned system hydro resources (as distinguished from the Mid-C hydro resources) to customers in the Northwest.[18/] Historically, some form of Hydro Endowment has always been recognized in the prior jurisdictional allocation methods. The Accord method used a load decrement approach to recognize the preference given the customers in the Northwest. Derivative allocation problems inherent in the load decrement approach led to the Modified Accord. This method used a fuel credit methodology for the hydro preference. Some form of recognition of Hydro Endowment has always been considered an absolute requirement by the Oregon and Washington parties representing consumer interests in the Multi-State

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18/ For purposes of this testimony I will define the term Hydro Endowment in this manner.

Process. Limited recognition of the Hydro Endowment appears now to be acceptable to even the Utah parties, based on their acceptance of the Revised Protocol.

**Q. DID PACIFICORP RECOGNIZE THE HYDRO ENDOWMENT CONCEPT IN ITS ORIGINAL PROTOCOL AND REVISED PROTOCOL FILINGS?**

**A.** Yes. However, the Original Protocol method simply allocated the capital cost of the hydro facilities to the Northwest, but none of the energy costs. The Revised Protocol allocates the embedded cost of hydro to the Northwest, but credits it against the difference between average system cost of thermal resources and the hydro resources.

In the Revised Protocol, PacifiCorp has proposed to use the same embedded cost credit methodology for allocation of certain Mid-C resources coupled with a situs assignment of the QF plants. However, some of the Mid-C contracts are also allocated to eastern states.

**Q. HAS PACIFICORP DEVELOPED AN ANALYSIS OF THE BENEFITS OF THESE FEATURES IN THE REVISED PROTOCOL?**

**A.** Yes. Confidential Exhibit No.___(RJF-4C) shows PacifiCorp's analysis of the rate impacts for the period 2005 to 2018 for the Revised Protocol as compared to the Rolled-in and Modified Accord methodologies. This analysis comes from the confidential workpapers supporting Exhibit No.___(DLT-5) provided in response to ICNU DR No. 5.16. Underlying this analysis is a calculation of the year by year revenue requirements of the Revised Protocol and a calculation of the yearly "credits" and costs associated with the Hydro Endowment and the Mid-C/QF allocation.

Based on the analysis, the Revised Protocol will produce a benefit to Washington of [redacted] compared to the Rolled-in method and [redacted] to Modified Accord (NPV 2005 to 2018). Compared to the overall Washington power costs in excess of [redacted] during the same period, this benefit is less than [redacted]. Given the vagaries of long-term projections, this may amount to little more than "noise."

Further, while Revised Protocol projections show savings for Washington from 2005 to 2011, after that, it will cost more than the Modified Accord method. Consequently, if the savings in the early years do not materialize in the amounts projected, Washington could end up paying more under Revised Protocol than Modified Accord.

**Q. IS THERE ANY REASON TO BELIEVE THIS WILL HAPPEN?**

**A.** The Revised Protocol was projected to save Washington [redacted] million as compared to Modified Accord for 2005. However, Exhibit No.___(DLT-6) shows that the savings are actually only $2.7 million. Consequently, the Company overstated the savings to Washington by [redacted] in just the first year in its projections of prospective impacts. This, and the approach PacifiCorp has taken regarding the mismatch between test years, shows that concerns of future benefits not materializing are well founded.

**Q. EXPLAIN THE HYDRO ENDOWMENT IN THE REVISED PROTOCOL.**

**A.** The Revised Protocol provides a credit based on the difference between the embedded cost of hydro facilities and PacifiCorp's thermal resources. Essentially the method gives Washington credit for the fact that the hydro resources have a lower average cost per MWh ($18.89/MWh) compared to the non-hydro resources ($33.73/MWh).[19] A similar credit is applied for the Mid-C resources.

Arguably this Hydro Endowment is a step in the "right direction," however, it is a rather small step. Based on the PacifiCorp analysis, the Hydro Endowment in the Revised Protocol is worth only [redacted] Net Present Value ("NPV") to Washington for the period 2005 through 2018. In reality, this approach provides only a very minimal Hydro Endowment and ignores some of the most important benefits of hydro to the system – most noticeably load shaping and dynamic overlay. In fact, if hydro were removed from the system, costs would increase substantially more than suggested by PacifiCorp's analysis.

**Q. IF THE REVISED PROTOCOL FAILS TO PRODUCE A SUBSTANTIAL HYDRO ENDOWMENT FOR WASHINGTON, THEN WHAT IS THE SOURCE OF BENEFITS TO WASHINGTON IN PACIFICORP'S STUDY?**

**A.** The Revised Protocol contains a revised Mid-C/QF allocation that the Company projects will produce benefits for Washington. Recent allocation methods have not featured a favorable allocation of the Mid-C contracts for the Northwest. However, the Revised Protocol includes a favorable allocation of the Mid-C contracts, though it is linked to a new situs allocation of QFs. The Net Present Value (2005-2018) benefit of the combined Mid-C/QF allocation is a benefit of [redacted] million to Washington based on PacifiCorp's modeling.[20] Thus, these features of the Revised Protocol are responsible for virtually all of the projected benefits to Washington.

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[19] Exhibit No.___(DLT-6).

[20] The seasonal allocation of peaking plants is slight detriment of [redacted] million to Washington (NPV 2005-2018), which almost exactly offsets the value of the proposed Hydro Endowment in the Revised Protocol.

There is uncertainty regarding the future value of the Hydro Endowment and the favorable Mid-C and QF allocations. Hydro variability is substantial, and there is uncertainty regarding the outcome of the re-licensing process and the Mid-C contract renegotiations. This is a serious problem because there is no assurance that, once hydro re-licensing is completed and these costs are borne by the Northwest, other states will not reject the validity of the Hydro Endowment and Mid-C allocations. In fact, the projections used in the current studies presented by the Company assume larger hydro benefits and lower hydro re-licensing costs than in the past. In recent workshops some representatives of eastern states have complained that the current allocation system under the Revised Protocol may no longer be a reasonable compromise. This does not bode well for the sustainability of the agreement as it raises the specter of other states rejecting the agreement in the future after receiving the benefits of rate caps.

The QF contracts have been above market for a very long time, and it appears there is little opportunity for re-negotiation in the future. Consequently, there is substantial uncertainty as to the Hydro and Mid-C energy costs, but relative certainty as to the cost and generation available from the QF contracts.

### 2. Cost Shifting

**Q. MR. DUVALL TESTIFIES THAT THE DYNAMIC ALLOCATION PROCESS USED IN THE REVISED PROTOCOL METHODOLOGY LIMITS THE IMPACT OF DIFFERENCES IN LOAD GROWTH ACROSS STATES.[21/] PLEASE COMMENT.**

**A.** Mr. Duvall testifies that this was one of the concerns expressed in the MSP, and he believes that the Rolled-in methodology proposed provides an adequate solution. He does so based on various studies that indicate approximately 100% of the cost of a new resource is picked up by the fastest growing state. Thus, he believes "cost shifting" is not a major concern.

However, there are some significant problems with his analysis of this problem. First, the mechanism used in the Revised Protocol does not provide any structural safeguard against cost shifting. In fact, the results cited by Mr. Duvall stem largely from coincidence—i.e., that a faster growing state is allocated more of all system costs (transmission, overheads, and other generators) offsetting the costs of new resources.[22/] While this result may occur under current load expectations, fuel costs, and overall cost levels, there is nothing to suggest this result will occur under different conditions. Thus, the solution is not necessarily "robust" enough to permanently provide the solution as claimed by Mr. Duvall.

Second, the studies presented by Mr. Duvall do not fairly represent the ratemaking approach the Company is advocating for Washington in this case. In the growth studies, the Company assumes that increases in Utah load also increase Utah's share of system costs vis-à-vis the other states. However, in the current filing, this is not the case because the allocation factors used are based on

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[21/] Exhibit No.___(GND-1T) at 17.
[22/] Id. at 18.

historical load levels (the 12-month period ended September 30, 2004) while power costs and power plant investment represent FY 2007. As a result, Washington gets the "worst of both worlds" in that loads and allocation factors are predicated on lower Utah demands, while power costs and new plant investment reflect the need to serve future Utah loads. While Washington is assigned plant and power costs of future growth, allocation factors, sales, and revenues are not matched to those higher loads.

Finally, Mr. Duvall's study does not address projects that have already been built or are under construction. There is a substantial difference in the allocation of costs of the project depending on the methodology selected for jurisdictional allocation. However, Mr. Duvall's study does not shed any light on the question of cost shifting vis-à-vis recently constructed resources. The reason is that in the growth studies, plants already built, and those under construction, are "frozen," and thus, do not change in response to changes in load. Consequently, the costs of plants recently completed or under construction cannot be "shifted" in the lower load growth scenarios he models.

The same problem will also exist for all new plants as they come on line. Once the Company has committed to construction of a plant, it is fixed in the Company methodology. Thus, the growth study will never show plants under construction (as Currant Creek and Lakeside are now) as resulting in cost shifts. This means that the methodology used by the Company fails to realistically address the problem.

In summary, a major defect of the Revised Protocol is that it has not developed a structural remedy for the cost shifting problem. At best, it provides protection based on the Company's hypothetical plants out in the future, under certain assumptions. However, it does not provide protection for cost shifts resulting from plants recently completed, or any prospective plant once construction begins.

**Q. THE MSP STANDING COMMITTEE IS CHARGED WITH STUDYING THE COST SHIFTING ISSUE AND DEVELOPING STRUCTURAL PROTECTION MECHANISMS FOR DEALING WITH THIS PROBLEM. DOES THIS PROCESS OFFER A POTENTIAL SOLUTION TO THIS ISSUE?**

**A.** That remains to be seen. I have participated in the load growth workshops and can report that a little progress has been made. The workgroup has identified some possible solutions, and there is a proposal before the group (presented by the Oregon Commission Staff representative) that would address the problem of prospective plants after construction begins. However, the group has not yet reached any conclusions, and it is very unclear whether it will actually capitalize on any of the progress made to date. Indeed, the Company is so pessimistic about the prospects for success that in its Final Draft Load Growth Report released in late September 2005, it states that "at the conclusion of the Load Growth Workgroup meeting held October 11, 2005, the workgroup participants were unable to reach consensus on the specifications of the preferred Structural Protection Mechanism ("SPM") or how such an SPM would be implemented."[23/]

[23/] Exhibit No.___(RJF-5) (excerpt from the Final Draft Load Growth Report).

**Q. DISCUSS THE APPROVAL OF THE REVISED PROTOCOL IN OTHER STATES.**

**A.** The Revised Protocol has been adopted by Idaho, Oregon, Utah, and Wyoming. All states placed conditions upon approval of the document. Idaho and Utah approved the Revised Protocol subject to rate cap provisions which limit its impact as compared to the Rolled-in method. The Utah and Idaho rate caps were the result of stipulations between the Company and parties in those states.

**Q. EXPLAIN THE UTAH STIPULATION IN MORE DETAIL.**

**A.** This agreement substantially moderates the rate impact of the Revised Protocol for that state. Thus, PacifiCorp has created a Utah-specific Revised Protocol because it has a fundamentally different effect on that state than other states. Consequently, there is no way in which the Revised Protocol proposed in this case for Washington will ever be comparable to Utah's modified Revised Protocol.

**Q. WHY IS THE UTAH STIPULATION OF CONCERN TO WASHINGTON?**

**A.** Under the terms of this agreement, PacifiCorp has agreed to hard caps on the rate impact of the Revised Protocol as compared to Utah's Rolled-in methodology. This reduced the overall revenue requirement from the Revised Protocol on Utah by $12.6 million in Utah's 2004 rate case alone.[24/]

**Q. DESCRIBE THE IDAHO RATE CAPS.**

**A.** The Idaho rate caps limit the revenue requirement impact of the Revised Protocol so that it will not exceed the Rolled-in allocation method by more than 1.67% for the period 2005 to 2009.

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24/ Exhibit No.___(RJF-6).

**Q. WHAT IS THE EXPECTED COST OF THESE SIDE AGREEMENTS AND WHY ARE THEY PERTINENT TO WASHINGTON?**

**A.** PacifiCorp's most recent studies show that these rate caps result in projected savings to Idaho and Utah [redacted] million for the period 2007-2014.[25]

This raises several "red flags" for Washington. First, by agreeing to limit the rate impact of the Revised Protocol as compared to Rolled-in, PacifiCorp now has a direct financial interest in minimizing the revenue requirements difference between Rolled-in and the Revised Protocol on Idaho and Utah. While Revised Protocol will not directly allocate these costs to other states, situations may arise where some of these costs not allocated to Idaho and Utah will end up being a detriment to other states. For example, implementation of a structural protection mechanism may be hindered by the limits on costs allocable to Utah.

Further, the Company will no longer be in a position to serve as an "honest broker" as regards any disputes concerning the proper interpretation of the document, or in its administration. This should be a very serious concern to the Washington parties because there is much "unfinished business" concerning analysis of cost shifting and the seasonal allocations that are to be addressed by the MSP Standing Committee under the terms of the Revised Protocol.

**Q. WHAT OTHER KINDS OF SITUATIONS COULD ARISE THAT ARE OF CONCERN?**

**A.** In the Revised Protocol there is a seasonal allocation for combustion turbines that is generally unfavorable to Utah. However, it does not apply to baseload coal or combined cycle plants. To minimize the difference between Revised Protocol and

[25] Exhibit No.___(RJF-13C) (PacifiCorp response to ICNU DR No. 2.133).

Rolled-in, the Company may perceive an advantage in selecting the latter types of resources. Assuming these plants are sited in Utah, that commission will have the sole authority for granting a Certificate of Convenience and Necessity ("CCN"). This means that Washington would have little or no opportunity to address a concern that an inappropriate resource selection was made.

Further, it is quite likely that the designation of a "State Resource" or situs allocation of an above market special contract will be a controversial aspect of the Revised Protocol. PacifiCorp will most certainly have an incentive regarding how it designates the specific contracts, particularly given the Idaho and Utah rate caps.

Another situation that might arise would be the re-negotiation of a contract. For Existing QF contracts, the entire amount of cost above current embedded cost is allocated on a situs basis. I will point out later that PacifiCorp has interpreted several QF contracts as new contracts, even though they pre-date the effective date of the Revised Protocol in Washington (or any other state, for that matter). This results in reduced costs being allocated to Utah and more to other states.

**Q. DOES THE UTAH STIPULATION GIVE THE COMPANY AN OPPORTUNITY TO PROPOSE A NEW ALLOCATION METHODOLOGY?**

**A.** Yes. The Utah agreement also offers PacifiCorp (and all the Utah parties) the opportunity to devise a new methodology if PacifiCorp finds that the Revised Protocol differs by more than 1% from the Rolled-in methodology after 2009:

4. Threshold for Continued Support of the Revised Protocol.

a. If, with respect to the Company's fiscal years 2010 through 2014, the Company's Utah revenue requirement, calculated pursuant to the Revised Protocol, exceeds or is projected by the Company in good faith to exceed 101.00 percent of the amount that would result from using the Rolled-in Allocation Method, the Company may propose a new interjurisdictional cost allocation method. All parties to this Stipulation agree to consider alternative interjurisdictional cost allocation methods in good faith and will use their best reasonable efforts to come to agreement on an amended Revised Protocol within 12 months after the Company proposes a new method.[26/]

This clause is significant to Washington. In approving the Revised Protocol, given the presence of such a side agreement, the WUTC would be acknowledging the option of the Company to propose a new method designed to further narrow the gap between Rolled-in and the Revised Protocol. In effect, the side agreement puts Washington (and the other states) on notice of the Company's right to propose a new method should the results differ by more than 1% from Rolled-in for Utah.

**Q. IN OREGON, THE COMPANY ALSO ENTERED INTO A STIPULATION CONCERNING THE REVISED PROTOCOL. BRIEFLY DESCRIBE THE KEY ELEMENTS OF THE STIPULATION BETWEEN PACIFICORP, THE OPUC STAFF, AND THE OREGON CITIZENS' UTILITY BOARD.**

**A.** This agreement has four basic elements:

1. An agreement to accept and support the Revised Protocol;
2. Language intended to provide some additional assurance about the permanence of the hydro preferences and the QF allocation;
3. Language preserving the rights of the stipulating parties to propose to change the Revised Protocol; and

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26/ Exhibit No.___(RJF-14) at 4.

4. An agreement to use a temporary tariff rider to reduce rates if the Load-Based Dynamic Allocation Factors are forecast to decline and PacifiCorp is over-earning by 200 basis points (ROE) or more.

Ultimately, the Oregon Commission approved the Revised Protocol and the supporting stipulation. This is further evidence that the Company has made concessions to parties in most other states to gain approval of the Revised Protocol.

**Q. HAS PACIFICORP PROPOSED ANY COMPARABLE RATE CAPS, SAVINGS GUARANTEES, OR OTHER CONCESSIONS FOR WASHINGTON?**

**A.** No.

**<u>Used and Useful Standard</u>**

**Q. WHAT ARE THE LEGAL STANDARDS THE COMMISSION MUST CONSIDER IN DECIDING THE INTERJURISDICTIONAL ALLOCATION METHOD?**

**A.** While I am not a lawyer, I understand that Washington law requires that a power plant must be "used and useful" in providing service to Washington customers before it can be put in rates.

**Q. HOW DOES THIS STANDARD IMPACT THE INTERJURISDICTIONAL ALLOCATION ISSUE?**

**A.** Most of PacifiCorp's power plants are located outside of Washington. Mr. Duvall points out that in prior cases the Commission has included the Dave Johnson, Colstrip, and Wyodak plants in Washington rate base.[27/] It appears based on this that the Commission viewed these plants as being sufficiently well connected to the PP&L grid to be used and useful for Washington. However, other plants that were part of the former Utah Power and Light Company, as well as the plants

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27/ Exhibit No.___(GND-1T) at 33-35.

acquired on the eastern side of the system since 1986, are further removed from the PP&L system. In all cases, the power from these plants most flow over one or more additional transmission links just to get to Colstrip or Jim Bridger (where it might eventually be transmitted to Washington) .

As shown on the GRID transmission topology map,[28/] power from Cholla, for example, must flow to Four Corners, then to East Main, then to Colstrip or Bridger, or from Four Corners to Colorado, to Tri-State, to Wyoming, and then to Jim Bridger. Once at Bridger it must flow to Idaho and then finally to West Main where it can be delivered to Washington.

Power from East Main must flow to either Amps/Colstrip or Jim Bridger before it can be transmitted to Idaho, then to West Main for delivery in Washington. All in all, the power from all of these eastern resources can hardly be considered to be directly connected to Washington.

**Q. DOES THE GRID TRANSMISSION TOPOLOGY MAP SHOW THE MAXIMUM AMOUNT OF POWER THAT CAN FLOW FROM EAST MAIN TO WEST MAIN?**

**A.** Yes. The map shows that the East Main to Bridger link can supply 104 MW, while East Main to Amps/Colstrip can supply 50-92 MW.[29/] East Main to Wyoming can supply 110 MW. However, the Wyoming to Bridger link cannot transmit any power during High Load Hour (“HLH”), but it can transmit the entire 110 MW during Low Load Hour (“LLH”).

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28/ Exhibit No.___(GND-2).

29/ Depending on the season. During HLH, the maximum is 50 MW.

However, Mr. Duvall testifies the Company does not have sufficient transmission rights to move all of its Colstrip power to Washington[30/] because the Colstrip to West Main link is only 70 MW. Consequently, the East Main to Colstrip link can never supply more than 70 MW during LLH and at most 50 MW during HLH, assuming that no Colstrip power is being sent to West Main. Because there is only 76 MW of capacity back from Colstrip to East Main, is seems the likely flow of power from Colstrip would be 70 MW to West and 76 MW to the east. This suggests that in the normal course of events, none of the East Main to Colstrip power actually makes it to Washington.

As a result, it is realistic to assume that typically only 104-154 MW can be transmitted during HLH (104 for East Main to Bridger and 50 for East Main to Colstrip).

There is also a possible path from East Main to Colorado (via Tri State) to Wyoming. However, the lack of HLH capacity from Wyoming to Bridger prevents this from providing a practical alternative. The GRID study demonstrates that this path (Colorado to Wyoming) is never actually used.

**Q. IS IT POSSIBLE TO DETERMINE HOW MUCH, IF ANY, POWER FROM THE EASTERN RESOURCES ACTUALLY ENDS UP PROVIDING SERVICE TO WASHINGTON CUSTOMERS?**

**A.** From examination of the GRID outputs it is possible to establish an upper limit. GRID provides reports that show the hourly, daily, and monthly flows of power across each transmission link. I examined these results and have calculated the

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30/ Exhibit No.___(GND-1T) at 34.

maximum possible amount of energy that can flow from East Main to West Main via the routes described above. The table below shows the results of this analysis.

**Table 2**
**Maximum Possible East to West Flow in GRID**

| Path | mWh | avg mW | HLH Max |
|---|---|---|---|
| East Main to AMP/Colstrip | 214,696.3 | 24.5 | 50 |
| East Main to Wyoming (LLH) | 58,766.3 | 6.7 | 0 |
| East Main to Bridger | 353,857.7 | 40.4 | 104 |
| Subtotal | 627,320 | 71.6 | 154 |
| Total Bridger & Colstrip Westward | 11,006,939 | 1256.5 | 1,413 |
| % of Total | 5.7% | 5.7% | 10.9% |
| **W/O East Main to AMP/Colstrip** | **412,624** | **47.1** | **104** |
| % of Total | 3.7% | 3.7% | 7.4% |
| Total PP&L Energy | 26,861,155 | | |
| Total % of PP&L Energy Reqmt. | 1.5% | | |
| Total Eastern (UP&L) Generation | 23,305,857 | | |
| Maximum % of Energy Transferred | 1.8% | | |

The table demonstrates that, at the very most, 71.6 average MW of energy flows from East Main to West Main via the routes described above. However, this estimate is likely to be greatly overstated. First, the table above merely shows the amount of energy delivered from East Main to Wyoming, Bridger, and Colstrip. That power may or may not be transmitted further to West Main (via Idaho or Colstrip). As discussed above, there is not even enough capacity to deliver all of the Colstrip capacity to the West so it is unlikely that the East Main to Colstrip path supplies any additional energy to the West. As a result, it is more appropriate to ignore the East Main to Amps/Colstrip transfers. Also, as discussed above, there is no path from Wyoming to Bridger in the HLH, so only the LLH transfers should be considered. This reduces the total flow to only 47.1 MW on average.

Second, the East Main power delivered to Bridger, Colstrip, or Wyoming may be used in those or other areas and never actually delivered to West Main.

The flow from East Main to Bridger, Colstrip, and Wyoming to West Main amounts to only about 5.7% of total flow from Bridger and Colstrip to West Main, or 3.7% excluding East Main to Colstrip.

Finally, total energy from East Main transmitted to West Main is only 1.5% of the total PP&L load requirement and less than 1.8% of the total energy generated by the eastern resources. Because Revised Protocol assigns approximately 8.5% of the cost of Eastern resources to Washington, it clearly assigns far more cost to Washington than is actually used to serve its load. In fact, it seems quite possible that none of the electricity generated by PacifiCorp's Eastern system resources actually provides service to Washington customers. In the end, the Company has the burden of proving that these facilities do provide generation to Washington. This information clearly suggests they are not used and useful for the state.

**Q. TIE THIS TO THE ISSUE OF INTERJURISDICTIONAL ALLOCATION.**

**A.** The above discussion presents a factual basis for the Commission to reach the legal conclusion that PacifiCorp's eastern resources are not used and useful for Washington. This would suggest that an allocation method that makes an adjustment to mitigate the impacts of these costly resources on Washington should be considered by the Commission. I present a method to address this problem, which I will describe shortly. I also expect other witnesses will present alternative concepts.

### 3. Pre-Merger ECD Method

**Q. CAN YOU DESCRIBE IN DETAIL YOUR ALTERNATIVES FOR WASHINGTON INTERJURISDICTIONAL ALLOCATION METHODOLOGIES?**

**A.** Yes, below is a discussion of my proposed revisions to Revised Protocol as well as my pre-merger allocation method.

**Q. PLEASE DISCUSS YOUR FIRST ALTERNATIVE, WHICH USES AN ALLOCATION METHOD BASED ON WASHINGTON'S PRE-MERGER RESOURCES.**

**A.** I propose a method that would "overlay" the pre-merger system costs of the PP&L system on the Revised Protocol methodology. In so doing, I would incorporate the Mid-C and Hydro ECD calculations into a broader based ECD that reflects assignment of all pre-merger resources to PP&L and allocates those to Washington based on its load ratio share. I call this proposal the "Pre-Merger ECD" method.

**Q. EXPLAIN THE PRE-MERGER ECD METHOD IN MORE DETAIL.**

**A.** To provide a practical ratemaking methodology, a complex new system design is somewhat undesirable. As a result, the logical approach is to start with PacifiCorp's filing and current application and modify it in the simplest way possible. The starting point for this analysis is PacifiCorp's Revised Protocol method. My ECD would reflect the cost of all pre-merger resources of PP&L. In this approach, I quantify the difference in embedded costs of the pre-merger PP&L resources and other resources.

**Q. HOW DO YOU ASSIGN EXISTING QF CONTRACTS?**

**A.** I allocate the cost of QFs assigned to pre-merger PP&L states on a "Rolled-in basis." Thus, Washington would be allocated costs of QFs in Oregon, Washington, California, and eastern Wyoming.

**Q. HOW IS THE ECD COMPUTED?**

**A.** I simply compute the difference between the average cost of energy from the pre-merger PP&L states and the system average cost. This credit is then multiplied by the generation of these resources and allocated to Washington. Exhibit No.___(RJF-7) shows the results of this analysis. The final adjustment is shown on Table 1. This is comparable to the amount that would result if Washington were to disallow the Gadsby and West Valley CTs and Currant Creek, $6.1 million.[31/] While the adjustment exceeds those disallowances, the remainder of the impact can be explained by the fact that the pre-merger PP&L system had lower cost resources than the UP&L system.

**Q. WHAT ARE THE ADVANTAGES OF THIS APPROACH?**

**A.** First, there is the simplicity of this method, which requires only a minor modification to PacifiCorp's filed case. Thus, the Company will not need to maintain radically different models for different states.

Second, there is the equity benefit of having Washington pay for resources it had before the merger.

Third, this approach effectively reduces the cost impact of new resources added to meet load growth onto the eastern system. As new resources are added,

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31/ See Exhibit No.___(RJF-15) (PacifiCorp responses to ICNU DR Nos. 2.1, 2.2, and 7.5). Also, GRID studies have been made to remove these units from net power costs.

the ECD credit for Washington would increase, thus resulting in a greater shielding from cost shifting. Units such as Gadsby, West Valley, and Currant Creek, built to serve Utah load growth and not used and useful for Washington customers, are therefore more effectively allocated to the east. This would mitigate the need for a complex structural protection mechanism to address the growth issue.

Finally, as the system evolves, the value of the ECD will change. Ultimately, it may become smaller, as low embedded cost resources are retired and replaced with higher cost resources in the future.

**Q. WHAT ARE THE DISADVANTAGES OF THIS APPROACH?**

**A.** Certainly, it seems unlikely that the eastern states would agree to this approach, and it amounts to a substantial departure from the Revised Protocol. Consequently Washington may not have a voice on the Standing Committee. Washington's participation might help balance the Standing Committee because at present it has three representatives from eastern states (Idaho, Utah, and Wyoming) and only one from the west (Oregon). Further, because PacifiCorp has provided rate caps to Utah and Idaho, there is the possibility that the Company will "tilt to the east" in matters that come before the Standing Committee, effectively overwhelming the interests of the western states.

### 5. Revised Protocol Conditions for Approval

**Q. ASSUMING THE COMMISSION WANTS TO ADDRESS THE SHORTCOMINGS IN THE REVISED PROTOCOL RATHER THAN USING THE PRE-MERGER ECD, WHAT IS YOUR RECOMMENDATION?**

**A.** The Washington Commission should address certain defects in the document. Washington can certainly place conditions upon its approval of the Revised Protocol that are consistent with the approaches taken by other approving states, and which may resolve some of the problems surrounding this approach.

**Q. WHAT CONDITIONS WOULD YOU RECOMMEND?**

**A.** PacifiCorp should be required to implement rate caps to ensure the savings projected by the Company under the Revised Protocol actually materialize.[32] I have developed rate caps for two periods, 2005 to 2011, and 2012 to 2018. Over the first period the Company would be required to guarantee savings of 2% compared to Modified Accord. After that it would be required to ensure that Revised Protocol costs Washington ratepayers no more than 1% more than Modified Accord. These figures were developed by averaging the projected savings in each period. Conceptually, this rate cap mechanism is no different from that which the Company has already agreed to in Idaho and Utah. However, unlike those two states, so long as PacifiCorp's projections prove reasonable, it need not result in any costs being borne by the Company. This adjustment would not result in any additional reductions to test year revenue requirements because the other adjustments shown on Table 1 combine to produce a 2.0% savings overall for the test year.

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[32] Exhibit No.___(RJF-4).

**Q. ARE THERE OTHER CONDITIONS THE COMMISSION SHOULD PLACE UPON ITS APPROVAL OF THE REVISED PROTOCOL?**

**A.** Yes. The Commission should reserve its right to implement its own "growth protection mechanism" if the MSP Standing Committee does not develop an acceptable Structural Protection Mechanism, applicable to Washington in future cases if it is needed to address cost shifting.

Further, as discussed shortly, the Commission should require the PCAM (if approved at all) to contain a "growth protection measure" to be described shortly. Finally, Washington should participate on the Standing Committee.

**Q. WOULD ANY ADJUSTMENTS BE REQUIRED TO PACIFICORP'S TEST YEAR IN THIS CASE?**

**A.** Yes. First, the Commission should reverse the production factor adjustment to remove its detrimental impact on the ECD credit. This was discussed above. It is crucial to do so because the production factor adjustment reduces the value of the ECD to Washington. Because the Revised Protocol benefits projected for Washington are so minimal, it is necessary to ensure customers receive the full value of the ECD. The impact of this adjustment is shown on Table 1.

Second, the Commission should require that the Company use only a historical test year in its application of the Revised Protocol. As discussed earlier, it is not reasonable for Washington to be the only state that uses historical revenue, expense, and loads for development of allocation factors, but use projected loads for computing power costs, particularly when the Company is requesting rate-base treatment of new plants. Currant Creek was not part of the system during the historical September 30, 2004 test year. Thus, it was not used and useful in the test year and its costs should not be "pro-formed" into the test year. If it is, then Washington will be bearing the cost of the new resource, but not having the advantage of a lower jurisdictional allocation factor that accompanies the growth giving rise to the need for the resource. In other words, the Company should not be allowed to use historical loads for some purposes, but projected growth (mostly from Utah) to support inclusion of new plants. Removing Currant Creek from the test year not only results in a reduction to the revenue requirement, but also a slight increase to variable net power costs. The net adjustment is shown on Table 1.

**Q. ARE YOU SUGGESTING A PERMANENT DISALLOWANCE OF CURRANT CREEK?**

**A.** No. In future cases, when the plant is actually operational within the historical test year, the Company could request is inclusion in rates. At that time the issues of prudence and used and useful would be addressed.

**Q. ARE THERE ANY OTHER ISSUES THAT MUST BE ADDRESSED IF THE REVISED PROTOCOL IS ADOPTED BY THE COMMISSION?**

**A.** Yes, there is one more adjustment to the test year that is required. The Company has not correctly applied the Revised Protocol as it applies to Existing QF contracts. The Company has assigned several Existing QF contracts on a system basis. However, certain costs of these contracts should be assigned on a situs basis. These contracts are the US Magnesium, Desert Power, Kennecott, and Tesoro QF contracts.

**Q. PLEASE EXPLAIN.**

**A.** Under the Revised Protocol methodology, costs in excess of embedded cost for Existing QF contracts are assigned on a situs basis in the ECD methodology. In the Revised Protocol document, Existing QF contracts are defined as follows:

> **"Existing QF Contracts"** means Qualifying Facility Contracts entered into prior to the effective date of this Protocol, but not such contracts renewed or extended subsequent to the effective date of this Protocol.

**Q. HOW DOES THE REVISED PROTOCOL DEFINE THE "EFFECTIVE DATE?"**

**A.** The "effective date" is not a defined term in the Revised Protocol, and there is some possible ambiguity concerning this date.[33/] However, for Washington there are only two logical choices: either the date of the Company's filing (May 2005) or the date the Revised Protocol is approved by the WUTC in this case. In either case, the effective date for Washington will be later than the first delivery date or the signing dates of the contracts listed above.

**Q. WHAT IS THE BASIS FOR THESE ASSUMED EFFECTIVE DATES?**

**A.** It is possible that the Commission could decide to make the Revised Protocol effective the date of PacifiCorp's filing, or May 2005. However, Section D of the Revised Protocol document addresses the issue of the effective date:

> **D. Interdependency among Commission Approvals** The Protocol has been developed by the parties as an integrated, inter-dependent, organic whole. Therefore, final adoption of the Protocol by any of the Commissions of Oregon,

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33/ The document does reference a "proposed effective date" that merely is a suggestion that the Protocol be applied to rate cases starting in June 2004. Because effective date is not a defined term, and subsequent language in the Protocol addresses the issue of effective date, the "proposed effective date" language is of no consequence. Further, as the document cannot be effective before its Commission approval, the proposed effective date is meaningless. In any case, the Company declined to request that the Commission make the document effective in 2004 in Docket No. UE-032065.

> Utah, Wyoming and Idaho, is expressly conditioned upon similar adoption of the Protocol by the other mentioned Commissions, without any deletion or alteration of a material term, or the addition of other material terms or conditions. Upon any rejection of the Protocol, or any material deletion, alteration, or addition to its terms, by any one or more of the four Commissions, the Commissions who have previously conditionally adopted the Protocol shall initiate proceedings to determine whether they should reaffirm their prior adoption of the Protocol, notwithstanding the action of the other Commission or Commissions. <u>The Protocol shall only be in effect for a State upon final adoption by its Commission.</u> Absent the final adoption of the Protocol, the Company will continue to bear the risk of inconsistent allocation methods among the States.[34]

The document clearly specifies that the Revised Protocol is only in effect for a State upon <u>final adoption</u> by its Commission.

The Commission has certainly not approved the Revised Protocol, and specifically did not approve it in its Final Order in Docket No. UE-032065 on October 27, 2004. So it is clear that the document was not in effect at that time. As a result, the earliest the Commission could approve the document would be retroactive to the Company's filing in this case, though logically its final adoption should not be until the order is issued in this case, assuming the Commission adopts the Revised Protocol.

**Q. HAS THE COMPANY ALREADY ELECTED NOT TO UTILIZE THE REVISED PROTOCOL?**

**A.** Yes. PacifiCorp filed Docket No. UE-032065 in late 2003 under the Original Protocol method. In the course of the case it was revealed that the Company would have had a lower revenue requirement for Washington under the Revised

[34] Emphasis added.

Protocol than under the Original Protocol. However, in that case, the Company opposed ICNU's proposal to compute the Washington revenue requirement using the Revised Protocol (with certain adjustments). In September 2004, a decision in Washington was rendered based on a Stipulation that was premised upon the Original Protocol. Had the Company agreed to apply the Revised Protocol in that case, then it could now argue that these contracts are indeed Existing QF Contracts. Consequently, the fact that these contracts are not Existing QF Contracts for Washington stems from a decision made by the Company last year.

**Q. WHAT ARE THE DATES OF THE QF CONTRACTS LISTED ABOVE?**

**A.** These contracts were all in effect on or before January 1, 2005. Listed below is the initial delivery date for each contract:

US Magnesium—January 2005

Desert Power—September 2004

Tesoro—September 2004

Kennecott—October 2004

All four contracts commenced prior to the Company's filing in this case.

**Q. HOW ARE THESE CONTRACTS TREATED IN THE ECD CALCULATION?**

**A.** None of these contracts' costs are assigned on a situs basis in the ECD. Rather, they are allocated on the SG factor.[35/] Because all four contracts have prices that exceed embedded costs, the excess of contract price over embedded cost should be assigned situs. Table 1 shows the reduction to the Washington revenue requirement accompanying this correction.

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[35/] See Exhibit No.___(RJF-16) (Re PacifiCorp, OPUC Docket No. UE 170, PacifiCorp response to OPUC Staff DR No. 403).

## IV. PCAM ISSUE

**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 PCAM. Specifically, I show why the arguments the Company uses in support of this 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 identify a number of issues the Commission should resolve prior to authorizing a PCAM.

**Q. PLEASE SUMMARIZE YOUR PCAM TESTIMONY.**

**A.** I have concluded as follows:

1. **There are several serious design flaws in the proposed PCAM. The proposed PCAM is needlessly complex and inconsistent with the Revised Protocol. There is no deadband, and the sharing mechanism is not consistent with its Oregon PCAM proposal.**

2. **The PCAM proposal will shift costs to Washington from faster growing states. For this reason alone, the proposal should be rejected.**

3. **While I recommend against a PCAM, if the Commission decides to adopt one, I propose the Commission provide a more reasonable deadband and sharing mechanism, and make adjustments to eliminate the cost shifting problem.**

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 the PCAM concept.**

5. **Ms. Omohundro and Mr. Widmer support the PCAM largely on the basis that other utilities in Washington have such mechanisms and increased power cost risks. However, there is no demonstration by the Company that a PCAM is the best means to address the problem.**

6. **The Company provides no PCAM tariff and few details concerning how its proposed prudence review would operate.**

**7. PacifiCorp's PCAM will complicate the regulatory process. It would create the need for additional audits to verify actual power costs. Before allowing a permanent PCAM, the Commission should first hold a rulemaking proceeding to develop proper rules, procedures, filing requirements, and incentive mechanisms.**

**<u>Problems in the PCAM Proposal</u>**

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

**A.** No. The PacifiCorp proposal is flawed 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. The Company provides little support for the PCAM. Further, pass through mechanisms reduce incentives for efficiency and increase the overall regulatory burden.

**Q. ARE THERE IMPORTANT DEFECTS IN THE PCAM PROPOSAL?**

**A.** Yes. There are practical drawbacks and many policy issues with the PCAM proposal. I divide these into two categories: Design issues and Policy/Support issues. Below I identify the major components of my analysis in both categories:

**<u>Design Issues:</u>**

- Cost Shifting and Inconsistency with the Revised Protocol;
- Lack of Deadband and an Inappropriate Sharing Mechanism; and
- Inclusion of Non-Volatile Costs.

**<u>Policy/Support Issues</u>:**

- Justification/Need for a PCAM;
- Failure to Fully Address Recognized Problems with the PCAM Concept;

- Regulatory Complexity;
- Lack of Formal Rules and Procedures; and
- Lack of Audit/Reconciliation Process.

**Design Issues**

**1. Cost Shifting and Revised Protocol Inconsistency**

**Q. EXPLAIN THE PROBLEM OF COST SHIFTING AS IT PERTAINS TO THE PCAM.**

**A.** The proposed PCAM would allocate PacifiCorp's actual net power costs to Washington based on the Rolled-in allocation factors developed from the September 30, 2004 historical test year. As load grows in the months ahead, overall net power costs will increase. However, the increase in costs will not be allocated on the basis of Washington's share of system load growth, or even Washington's actual loads. Instead, the system power costs will be allocated on historical allocation factors, after some adjustments are made for the allocation of cost variances due to hydro resources and QF contracts. In the end, this process is highly inequitable, needlessly complex, and inconsistent with the Revised Protocol.

**Q. WHY DO YOU CONSIDER THE PCAM HIGHLY INEQUITABLE?**

**A.** As discussed earlier, the cost of prospective load growth on the system is largely due to Utah. Washington loads have actually declined since the turn of the century, while Utah's have grown substantially. Washington is responsible for only about 1% of overall system load growth. Based on PacifiCorp GRID runs, the Total Company cost of load growth by 2007 is expected to reach $178 million.[36] The PCAM assigns this additional cost on a Rolled-in basis, rather than on the basis of cost responsibility. I demonstrated earlier in this testimony that through use of the PCAM, the Company would shift $4.9 million in costs of excess Utah load growth to Washington in FY 2007. On this basis alone, the proposed PCAM should be rejected.

**Q. WHY DO YOU CONTEND THAT THE PCAM IS NEEDLESSLY COMPLEX AND INCONSISTENT WITH THE REVISED PROTOCOL?**

**A.** The Company proposes to identify the causes of power cost variations due to hydro and QF variations in the actual cost balance, and then allocate those costs to states on the basis of certain allocators. These steps are not necessary to comply with the Revised Protocol. In fact, the Company purposely misapplies the Revised Protocol in its proposed PCAM.

**Q. EXPLAIN FURTHER.**

**A.** Under the PCAM proposal, the Company plans to use GRID model studies to determine the cause of power cost variations. For example, power cost variations related to Company owned hydro would be allocated to Washington on the basis of the DGP (17.25%) allocation factor. Power cost variations related to the Mid-C contracts would be allocated to Washington on the basis of the MC factor (12.0% for Washington). Situs allocators would be applied for the QFs. Most other costs would be allocated on a system basis using the SG factor (8.5% for Washington).

While Mr. Duvall contends that this process is "designed to allocate changes in costs and benefits for these three components in a manner that is

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[36] PacifiCorp's response to ICNU DR No. 9.3.

consistent with the initial allocation of the costs and benefits under the Revised Protocol" it does not do so.[37/] In fact, the proposal actually deviates from the Revised Protocol.

**Q. HOW DOES THE PCAM DEVIATE FROM THE REVISED PROTOCOL?**

**A.** To explain this, I will reference Mr. Duvall's recent Oregon testimony regarding the Revised Protocol:

> Under the Revised Protocol, all costs are allocated consistent with the Company's rolled-in methodology, with four exceptions. The first exception, Seasonal Resources, use monthly-weighted allocation factors, rather than annual allocation factors. While this is a change to the Company's rolled-in methodology, the costs of Seasonal Resources are still allocated on a system-wide basis. The other three exceptions result from the application of the Embedded Cost Differential (ECD) to Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts.[38/]

The ECD calculation computes the difference between the embedded cost of the hydro resources, the Mid-C and Existing QF contracts, and the embedded costs of other resources on the system. These costs (or credits) are then allocated to states on certain special allocators (DGP for hydro, MC for Mid-Columbia, and situs for existing QFs). Because hydro and the Mid-C contracts cost less than other resources, they produce a benefit to Washington.

The problem with the PacifiCorp proposal is that it uses the DGP and MC factors to allocate the difference in system incremental costs (primarily fuel and purchased power expense) to Washington as if those costs were equivalent to the embedded costs used in the ECD calculation. In effect, the Company proposes to

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[37/] Exhibit No.___(GND-1T) at 28.

[38/] Re PacifiCorp, OPUC Docket No. UE 173, Direct Testimony of Greg Duvall at 2 (Apr. 15, 2005).

assign Washington a disproportionate share of the impact of hydro generation variations.

**Q. HOW SHOULD THE PCAM ALLOCATION OPERATE IN ORDER TO BE CONSISTENT WITH THE REVISED PROTOCOL?**

**A.** When there is a hydro shortfall, the system response is to increase generation from thermal units and purchase more power from the wholesale market. In contrast, when there is a hydro surplus, the system response is to decrease generation from thermal units and purchase less power from the market. Fuel and purchased power expenses are normally allocated in rate cases under Revised Protocol on a System basis (using the SE or SG allocators). Under the Revised Protocol, Washington bears about 8.5% of these costs. Based on the PacifiCorp PCAM methodology, however, Washington would likely be assigned twice this amount of cost responsibility.

In a rate case, there also would be a subsequent calculation of the ECD adjustment between the states. Fuel and purchased power costs are included in the ECD calculation. If more fuel and purchased power expense is incurred, it would increase the embedded cost of non-hydro resources and increase the value of the credit allocated to Washington by the DGP and MC factors. There would also be a change in the average cost per MWh of hydro generation because the amount of energy produced by hydro would be changed. These, however, are not substantial effects, and therein lies the problem with the PacifiCorp proposal. Rather than actually re-computing the revenue requirement, the Company would make a very crude approximation that consistently assigns far too much of the impact of hydro variations to Washington.

**Q. DO YOU BELIEVE THAT THE ECD PORTION OF THE CALCULATION SHOULD EVEN BE APPLIED IN A PCAM SETTING?**

**A.** Not unless it is applied to all states at the same time in exactly the same manner. The ECD credit is not an incremental cost to the Company in the same sense as increased purchased power and fuel expenses resulting from a hydro shortfall would be. The reason is that the ECD amounts to an "after the fact" allocation of costs among the states, not an incremental cost of hydro variations to the Company. The ECD calculation is a "zero sum game" between the states, and does not have any impact on shareholders, so long as all states are treated in the same manner. If the cost of fuel goes up because of poor hydro, the Company has no choice but to pay for more fuel. However, it does not follow that the Company would at the same time incur a cost because its allocation of the ECD among the states had theoretically changed. Indeed, unless the Company has an identical and simultaneous PCAM in every state, there will be no ECD dollars flowing between the states. Therefore, unless all Commissions approve of a completely equivalent PCAM, the Commission should completely ignore the ECD aspect of this analysis. At this point, that is very unlikely because the Company has not even proposed a PCAM at present in California, Idaho, or Utah[39/] and its Oregon proposal is currently opposed by the OPUC Staff, the Citizens' Utility Board, and ICNU.

Further, because the ECD is based on normalized hydro levels, it is a legitimate question as to whether it should even be adjusted in a PCAM setting, if actual hydro conditions differ from normalized ones. Recall that, while

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[39/] Exhibit No.___(CAO-1T) at 7-8.

PacifiCorp used the Modified Accord Fuel Credit for general rate cases in the past, it never reflected any changes to the fuel credit in the various deferral cases (e.g., UE-020417) it filed as a result of the power crisis or its aftermath.

Finally, it is quite ironic that the Company would choose to implement these "complications" to the PCAM on the basis of the Revised Protocol, while as the same time ignoring the more significant issue of cost shifting created by the PCAM.

**Q. CAN YOU TIE THIS INTO YOUR COMMENT THAT THE PCAM IS "NEEDLESSLY COMPLEX?"**

**A.** Ultimately, a PCAM (if permitted at all) should only deal with the incremental costs of power cost variations. These are basically fuel and purchased power and should be allocated under the Revised Protocol using the system allocators only. There really is no need for the complications of the additional GRID studies required to decompose the power cost variations into specific causes. If a PCAM were allowed at all, there really is no need for the Commission to deal with revising the ECD component of the calculation, or to use "special allocators" for hydro, Mid-C, and QFs. Only if the Company proposes an identical PCAM for each state should the Commission consider allowing the Company to reset the ECD credit in response to changes in system hydro conditions.

### 2. <u>Deadband and Sharing Mechanism</u>

**Q. DESCRIBE THE SHARING MECHANISM IN THE PCAM PROPOSAL.**

A. The Company proposes to allocate 90% of power cost variances to customers and 10% to shareholders, except for those related to QF contracts.

**Q. IS THIS A REASONABLE SHARING MECHANISM?**

**A.** No. First, there is no deadband in the PCAM proposal. Second, the proposed sharing bands place too much cost responsibility on customers. Both aspects of this proposal are extremely poor public policy and inconsistent with past Commission practice.

**Q. PLEASE EXPLAIN.**

**A.** While the Company justifies its PCAM on the basis that Avista and PSE both have PCAMs at this time, the Company ignored the fact that in both cases a deadband is used. While Avista has a $9.0 million deadband, and PSE has a $20 million deadband, PacifiCorp proposes to have no deadband at all. While Avista and Staff have proposed to narrow the Avista deadband in the current Avista rate case, their agreement is in the context of a contested settlement.

Further, the sharing mechanism proposed by PacifiCorp is much more generous than the PSE sharing mechanism. For PSE, sharing bands range from 50% to 95%, depending on the overall power cost variance:

> PSE must absorb the first $20 million of excess costs, half of the next $20 million, 10 percent of the next $80 million, and 5 percent of any amounts that exceed $120 million. Id. In like fashion, if power costs are lower than the PCA baseline, PSE retains the first $20 million in savings, half of the next $20 million, 10 percent of the next $80 million, and 5 percent of any amounts that exceed $120 million."[40/]

By limiting the sharing mechanism to 90% the Company would greatly reduce any incentives it has to minimize power costs. As noted by Mr. Widmer, the

[40/] Re PSE, WUTC Docket No. UE-011570, Twelfth Suppl. Order at ¶ 23 (internal footnotes omitted).

Company is requesting only a 70% sharing percentage in Oregon.[41/] While I do not find the 70% sharing mechanism proposed in Oregon satisfactory, it is preferable to the 90% sharing proposed by the Company in Washington.

**3. Definition of Power Cost and Inclusion of Costs That Are Not Highly Volatile**

**Q. DOES THE PROPOSED PCAM INCLUDE INAPPROPRIATE COSTS?**

**A.** Yes. Based on Mr. Widmer's testimony[42/] and Exhibit No.___(MTW-7), the Company wishes to include a wide variety of costs in the PCAM. This apparently includes all items the Company might classify as "actual net power costs" such as fuel and purchased power costs, transmission costs, long-term contract costs, hedges, and options. The Company actually provides no specific definition of allowable actual power costs, but instead provides only an example based on 2004 actual data. This definition is far too nebulous for a permanent PCAM and should be rejected. If the Commission decides to approve a PCAM, then it should first limit eligible costs to only those expenses that are "volatile," "significant" and "beyond the Company's control." This would eliminate solid fuel costs, transmission expenses, and long-term contract costs.

**Q. WHY WOULDN'T YOU INCLUDE SOLID FUEL COSTS, TRANSMISSION EXPENSES, AND THE OTHER ITEMS IN A PCAM?**

**A.** One of PacifiCorp's major power cost expenses is for coal, a commodity whose price is fairly stable over time. It is quite normal within the industry to purchase

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41/ Exhibit No.___(MTW-1T) at 32.

42/ "Adjusted actual net power costs are equal to actual net power costs adjusted to remove priorperiod adjustments recorded during the accrual period and to include Commission-adopted adjustments from the most recent rate case." Exhibit No.___(MTW-1T) at 33.

coal under long-term contracts. Thus, these expenses hardly qualify as costs that are volatile and/or beyond the Company's control.

Transmission expenses should not be part of a PCAM recovery mechanism either. These costs are not highly volatile and are not large in relation to total system costs, or even net power costs. There is no need for a PCAM to recover these kinds of costs.

**Q. IS THERE ANY NEED TO INCLUDE RECOVERY OF LONG-TERM CONTRACTS AND QF CONTRACTS IN A PCAM?**

**A.** No. These costs are, contractually specified and not highly volatile. There is no need to include such contracts in the PCAM because they do not create a substantial amount of power cost uncertainty. In some fuel and long-term purchased power contracts escalators are included that increase prices over time. The inclusion of such costs amounts to using a PCAM as a means of obtaining the benefits of a general rate case without actually having to file one. Such contracts would likely result in a PCAM that is not revenue neutral and provides the Company with "automatic" rate increases.

**4. <u>PCAM Corrections</u>**

**Q. ASSUMING THE COMMISSION WISHES TO ADOPT A PCAM FOR PACIFICORP, WHAT ARE THE MINIMUM RECOMMENDATIONS YOU WOULD MAKE?**

A. In that case, the Commission should implement a broad deadband and use a sharing mechanism that places more cost responsibility on the Company. Further, as discussed above, there is no need for the complications created by the special treatment of Hydro, Mid-C, and QF contracts. Instead, power costs should be allocated on the SE and SG factors alone as appropriate. Finally, the Commission should implement a growth protection measure in the PCAM to ensure that costs from higher growing states are not allocated to Washington.[43/]

**Q. EXPLAIN HOW THAT MECHANISM WOULD WORK.**

**A.** The Company should prepare GRID runs that measure the amount of cost shifting that has been caused by actual unequal growth. I suggest the Commission require one GRID run based on September 30, 2004 load levels, another one based on the assumption that the high growth state(s) grow at the same rate as the remaining states, and a third run based on actual sales growth for the high growth state(s). The difference in cost between the second and third runs would then be removed from Washington's allocation of system power costs.

**Q. WHY WOULD YOU MAKE A SPECIAL ALLOCATION FOR GROWTH BUT NOT FOR HYDRO, MID-C AND QF GENERATION?**

**A.** I have already discussed above the reasons why these special hydro allocations are unnecessary. It is also important to realize that over the long term, hydro variations should balance out to zero. However, there has been a persistent pattern of unequal growth among the states, and that pattern is expected to continue. That being the case, Washington ratepayers would systematically be assigned costs of the higher growth state(s) unless some protection mechanism is employed.

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43/ This is assuming the Commission adopts the allocation methodology based on the Revised Protocol allocators.

## Policy/Support Issues

### 1. 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 less than eight pages of testimony presented by Ms. Omohundro[44/] and three pages from Mr. Widmer.[45/] Ms. Omohundro supports the proposed PCAM as follows: 1) a PCAM is needed due to volatility and asymmetric power cost risks; 2) other utilities in Washington have a PCAM; and 3) a PCAM could "positively influence" PacifiCorp's credit rating. Mr. Widmer's testimony is largely duplicative or supportive of Ms. Omohundro's testimony.

Neither witness presents any substantial evidence concerning the need for the PCAM, the inadequacy of PacifiCorp's bond ratings, nor any financial difficulties the Company would endure without a PCAM.

**Q. THE FIRST JUSTIFICATION FOR THE PCAM CONCERNS POWER COST VOLATILITY AND ASYMMETRIC RISK. PLEASE COMMENT.**

**A.** Again, the discussion in Ms. Omohundro's testimony is very broad and general. There is no specific evidence presented to establish that the current level of power cost volatility poses a serious problem for the Company.

Mr. Widmer argues that there is an asymmetric risk of power cost variation because cost increases are theoretically unlimited, but costs can only decline to zero.[46/] However, Mr. Widmer is wrong on both counts. Certainly, power costs cannot increase infinitely without limit (nothing can). However, it

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44/ Exhibit No.___(CAO-1T) at 2-9.
45/ Exhibit No.___(MWT-1T) at 29-31.
46/ Exhibit No.___(MTW-1T) at 29.

would not be impossible for them to become negative. While certainly an extreme possibility, if the Company was "long" on capacity and energy, and the rest of the market very short, the Company could well make more money on surplus power sales than it spent to produce it.

**Q. IS IT LIKELY THAT MARKET PRICES WILL INCREASE MORE IN BAD HYDRO YEARS THAN THEY DECLINE IN GOOD HYDRO YEARS, THUS RESULTING IN ASYMMETRIC POWER COST RISKS?**

**A.** There is no evidence in this case to prove that possibility exists and GRID is not capable of modeling such a scenario. However, this does seem plausible on an intuitive basis. If PacifiCorp was a substantial purchaser of power, instead of a net seller, that possibility might be a more substantial concern.

In any case, it is not the overall distribution of power costs that is the real issue—it is the likelihood of a positive or negative power cost variance (the difference between the power costs reflected in rates, and the actual result) that matters. There is no reason to expect that the Company will consistently underestimate power costs. Indeed, the Company has every incentive to overestimate its power costs in regulatory proceedings. The Commission, however, has no incentive to authorize power costs that are too low or too high, so there is little reason to fear a "systematic" bias towards underrecovery of power costs.

Finally, there is no explanation provided by either Ms. Omohundro 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 PacifiCorp's parallel current proceeding 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/]

**Q. THE SECOND ARGUMENT MS. OMOHUNDRO ADVANCES IN SUPPORT OF THE PCAM IS THAT OTHER UTILITIES IN WASHINGTON HAVE ONE. PLEASE COMMENT.**

**A.** That is true, though this seems more like the kind of argument one hears in relation to setting a child's weekly allowance. However, Ms. Omohundro failed to mention some important facts. First, the Avista and PSE PCAM mechanisms were both 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 hardship when the PCAMs were first implemented. Indeed, the WUTC adopted those PCAMs as tools for restoring the financial health of both companies:

> This Order marks the culmination of significant efforts by the parties, and by the Commission, to help restore the financial integrity of one of Washington State's major electric utilities, and to help ensure that PSE's customers continue to receive reliable electric service at reasonable rates.[48/]
>
> * * *
>
> This Order marks the culmination of significant efforts by the Parties, and by the Commission, to help restore the financial integrity of one of Washington State's major electric utilities, and

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47/ Re PacifiCorp, OPUC Docket No. UE 173, Galbraith Direct at 7, 22-23.

48/ Re PSE, WUTC Docket No. UE-011570, Twelfth Suppl. Order at 3 (June 20, 2002).

to help ensure that Avista's customers continue to receive reliable electric service at reasonable rates.[49/]

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[50/] and Avista had lost it investment grade status.[51/] PacifiCorp alleges no such financial hardship at this time, and there is no stipulation indicating the unanimous support of other parties for its PCAM in this case. As a result, the comparison to Avista and PSE is simply not warranted because the backgrounds are substantially different.

**Q. PLEASE COMMENT ON MS. OMOHUNDRO'S THIRD POINT CONCERNING BOND RATING IMPROVEMENT.**

**A.** It would be pure speculation to claim PacifiCorp's bond ratings will actually improve with approval of a PCAM. Ms. Omohundro does not actually testify that the Company will experience improved credit ratings. She merely notes that rating agencies have expressed some concern over the lack of a PCAM and loosely suggests that adoption of a PCAM would have a "positive influence" on the Company's credit rating.[52/] The same might be said if the Commission simply announced that it planned to increase PacifiCorp's rate of return in its next rate case. However, that would not make it a wise policy decision for the Commission.

Ultimately, the Commission has little to go on with respect to the credit rating issue. Even if the Commission is convinced that a credit rating improvement would occur, there is no evidence produced by the Company to

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49/ Re Avista Corp., WUTC Docket No. UE-011595, Fifth Suppl. Order at 3 (June 18, 2002).
50/ Re PSE, WUTC Docket No. UE-011570, Hadaway Direct at 3.
51/ Docket No. UE-011595, Fifth Suppl. Order at 4.
52/ Exhibit No.___(CAO-1T) at 6.

establish that its current credit rating is too low, or how much ratepayers would save from an improved credit rating. The Company offers no "cost-benefit analysis" of this proposed regulatory change.

**Q. ASSUMING THAT WHOLESALE MARKET VOLATILITY IS HERE TO STAY, IS A PCAM THE BEST MEANS OF DEALING WITH IT?**

**A.** No. In fact, a PCAM might well have the opposite effect. It might shield PacifiCorp from the most serious risks of market volatility to such an extent that the Company does not develop effective long-term solutions to the problem of its dependence upon the wholesale market.

**Q. PLEASE EXPLAIN.**

**A.** Ultimately, the best solution to an erratic power market may be to limit exposure to it through a portfolio approach. To do so, securing longer-term power supplies may be the best solution. By purchasing, leasing or obtaining long-term supply contracts tied to new or existing resources, the Company could reduce its dependence on short-term markets.

The problem with a PCAM is that it may eliminate the most substantial risks to PacifiCorp from its market-based balancing strategy. Thus, implementation of a PCAM could provide PacifiCorp the incentive to continue a potentially more risky strategy of overreliance on the market, and avoid the more risk-averse strategy of building or purchasing the output of new capacity. If the Commission is concerned about that issue, then a PCAM may be exactly the wrong solution to the problem.

**Q. MR. WIDMER CONTENDS THAT EXHIBIT NO.___(MTW-4) SHOWS THE COMPANY'S EXPOSURE TO POWER COST RISK HAS INCREASED. PLEASE COMMENT.**

**A.** This exhibit is really not relevant to this case, as it shows power cost exposure (as defined by Mr. Widmer) for Oregon for 1990 to 2000. Mr. Widmer testifies that this is because the Company did not have Washington rate cases during that period.[53/] That case was settled. In any case, the "power cost exposure" data is not very meaningful for Washington because the Company found its earnings satisfactory enough in the 1990s to avoid Washington rate cases.

**2. Failure to Fully Address Recognized Problems with the PCAM Concept**

**Q. ARE THERE OTHER POLICY ARGUMENTS AGAINST USE OF A PCAM THAT PACIFICORP HAS NOT ADDRESSED?**

**A.** There are important issues the Company has not even considered or addressed in its testimony. For example, a PCAM can cause a major difference between the revenue effects of different kinds of power purchases and the accounting treatment of certain types of costs. Consequently, even if a particular supply strategy has the lowest total cost per kWh (when all costs are included), a higher-cost purchase transaction may be more profitable to the utility. Without a PCAM, the Company has a great incentive to minimize costs between rate cases, and would naturally select the lowest cost supply strategy. With a PCAM, the Company may have a financial incentive to select only purchase transactions that enjoy pass-through recovery, irrespective of total cost. Examples include:

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53/ Even this is factually incorrect because the Company did file a Washington rate case in 1999 (UE-991832).

a. A decision to purchase power vs. rent a combustion turbine. The CT rental may be lower in cost, but not PCAM eligible.

b. A situation where a lawsuit with another utility is resolved by offering a low-cost long-term power sale, such as in the case of the SMUD contract. A lawsuit judgment would most likely not be PCAM eligible, while the Company might assume that the cost associated with a below-market sale would be recoverable in the PCAM.

c. Renegotiation of a QF contract. An "Existing QF" contract might be renegotiated on unfavorable terms to reduce PacifiCorp's exposure to losses under the Utah rate cap. PacifiCorp might assume that the cost of the new contract would be recoverable in the PCAM.

d. The offer to buyout a long-term contract by purchasing the underlying asset might be turned down because the cost of the contract power might be PCAM eligible, while the cost of the plant would not.

e. A transaction requiring a minor transmission investment might be turned down in favor of a higher-cost transaction that required no investment.

f. A decision to litigate against a power or fuel supplier might be avoided because the savings would be passed through to ratepayers, while the cost of litigation would not.

**Q. IS THERE EVIDENCE THAT A PASS-THROUGH ACCOUNT DISCOURAGES EFFICIENCY?**

**A.** Yes. Exhibit No.___(RJF-8) is a copy of a portion of a presentation made by PacifiCorp concerning a heat rate improvement project. The document strongly suggests that when fuel costs are passed through to customers, there is little incentive for heat rate improvement. Conversely, when the power crisis occurred and power costs were not a pass-through, the Company initiated a heat rate improvement project. Certainly, if power costs are largely a pass-through item, efficiency improvement and capital investments will be discouraged.

**Q. HAS PACIFICORP PREVIOUSLY TAKEN A POSITION ON THE USE OF A PCAM TYPE APPROACH?**

**A.** Yes. The Company previously requested elimination of the Utah Energy Balancing Account ("EBA"). In his May 1990 testimony before the Utah Commission, PacifiCorp witness Verl R. Topham testified that elimination of the then existing PCA[54/] was necessary for several reasons.[55/] Mr. Topham argued that the EBA impeded the ability of management to respond appropriately to competition and to "manage the Company."[56/] He also stated that it raised questions about retroactive ratemaking.[57/]

Mr. Topham's most significant argument was that a PCA was no longer appropriate for the operating environment at the time. Mr. Topham testified that "conditions which may require a power cost adjustment (PCA) clause such as extreme volatility of fuel costs are not currently applicable to the Company."[58/] Based on the September 30, 2004 loads, more than 99% of the Company's native energy requirements are provided by coal, hydro generation, wind energy or QF contracts. Thus, one might question why volatility of fuel prices should now be a serious problem for the Company.

**Q. DID MR. TOPHAM DISCUSS THE REASONS BEHIND THE REQUEST TO ELIMINATE THE EBA IN UTAH?**

**A.** Yes. At the time, the Company was concerned about the need to reduce prices due to declining fuel costs. Mr. Topham testified that from March 1988 to May

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54/ Mr. Topham used the terms EBA and PCA more or less interchangeably in his testimony.
55/ Exhibit No.___(RJF-9).
56/ Id. at 5:5-12**.**
57/ Id. at 5:26-6:2.
58/ Id. at 4:18-21.

1990, changes in EBA collections resulted in substantial price reductions. This ran counter to PacifiCorp's goal of "price stability."[59/]

**Q. DID MR. TOPHAM INDICATE THAT THE COMPANY WAS WILLING TO ABSORB THE RISKS OF FLUCTUATING POWER COSTS?**

**A.** Yes. The following question and answer is included in Mr. Topham's testimony:

> Q. The EBA is a mechanism which places the risk of fluctuating power costs on the customer. If the EBA were terminated, the risks of fluctuating power costs would be placed on the Company. Why is the Company willing to accept this risk?
>
> A. The Company is willing to accept this risk because we believe the risk is manageable. <u>The Company believes in placing the risk of management practices on those that make the business decisions—management—not customers</u>.[60/]

It should not be lost on the Commission that the 1990s were characterized by falling fuel and wholesale power prices. Thus, the Company was willing to absorb the "risk" of <u>falling</u> commodity prices, but not falling retail prices. Now the Company seeks to place the risk of <u>increasing</u> commodity prices on Washington ratepayers—not management or shareholders. Ironically, the Company is not suggesting that it would also let the ratepayers "<u>make the business decisions.</u>"[61/]

### 3. <u>Regulatory Complexity</u>

**Q. WOULD A PCAM COMPLICATE AND INTENSIFY REGULATION?**

**A.** Yes, the presence of a PCAM could (or at least should) greatly complicate and intensify regulatory efforts. This could be manifested as confusion concerning

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59/ <u>Id.</u> at 12:24-13:21.

60/ <u>Id.</u> at 14:17-26 (emphasis added).

61/ <u>Id.</u> at 14:25-26 (emphasis added).

rate case settlements, increased gaming of accounting entries, and the need for more audits.

Under the PCAM proposal, the Company contends that it will make adjustments to remove costs disallowed in rate cases. The Company cites the SMUD contract as an example, however, the Company did not actually make any adjustment to SMUD in Exhibit No.___(MTW-7). If stipulations do not clearly identify costs that have been removed from the GRID study, there may well be confusion in ensuring that the same costs are removed from actual costs as well as being removed from normalized costs. Unless this is done, disallowed costs may be recovered in the PCAM.[62/]

**Q. CAN YOU PROVIDE AN EXAMPLE OF THIS KIND OF PROBLEM BASED ON EXHIBIT NO.___(MTW-7)?**

**A.** Yes. Exhibit No.___(MTW-7) is an illustration of the PCAM based on 2004 actual data. The testimony supporting the Stipulation in UE-032065 established the net power cost baseline Total Company figure of $534 million used in Exhibit No.___(MTW-7). The Joint Testimony supporting the Stipulation indicates that the final net power cost figure used in the Stipulation reflected the resolution of several issues, including the Aquila Hydro Hedge. However, in the actual cost figures used in Exhibit No.___(MTW-7), costs and receipts related to the Aquila Hydro Hedge are included. Both the Company and various parties would certainly be inclined to argue over whether those items should be reflected in the PCAM, perhaps depending on whether they were positive or negative.

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62/ This is why ICNU and the Company agreed to language concerning SMUD and IMC/Kalium issues in the Power Cost Stipulation. While this problem is potentially resolved in the current stipulation, similar problems might arise in future stipulations or a generic power costs stipulation between PacifiCorp and other parties in this proceeding.

**Q. WOULD PARTIES HAVE THE OPPORTUNITY TO IDENTIFY SUCH PROBLEMS UNDER THE PACIFICORP PCAM PROPOSAL?**

**A.** That is unclear. Mr. Widmer testifies that a prudence review is contemplated by the Company; however, he provides no details of how this would work. In any case, the issue of reasonableness of costs goes far beyond prudence. The Company has suggested no mechanism for ensuring that improperly classified or unreasonable costs may be removed from the PCAM actual cost balance. Indeed, the Company does not even seem to suggest any process for correcting errors in its application of the PCAM.

**Q. ARE THERE OTHER TYPES OF ACCOUNTING ISSUES THAT CAN ARISE WITH A PCAM THAT THE COMPANY HAS IGNORED?**

**A.** Certainly. The issue of the classification of costs from an accounting perspective becomes quite important with a PCAM. Without a PCAM, the utility has little incentive to engage in any accounting subterfuge between rate cases. With a PCAM, classification of costs as part of the pass-through account becomes highly profitable. Indeed, this kind of "gaming" creates the need for more, not less, regulatory oversight.

Further, questions of timing of entries can become quite important. Prior period costs might be included as part of the initial set of actual costs included in the PCAM, for example. The Company contends it will remove out-of-period costs. However, in the Oregon "Bridge Audit Case," OPUC Docket No. UE 116, it was learned that PacifiCorp's books are a confusing morass. In that case, the auditors found substantial issues with respect to the booking of costs into the proper period. In the end, it was impossible to develop a complete and accurate accounting of all prior period costs.

Issues can arise regarding whether various costs are capitalized or expensed. Under a PCAM, the utility would have greater incentive to expense rather than capitalize costs, particularly costs related to fuel supply or storage (assuming they are eligible for recovery). One could reasonably expect PacifiCorp to attempt to broaden the definition of allowable costs to be included in net variable power costs.

**4. <u>Lack of Audit/Reconciliation Process</u>**

**Q. BASED ON THE ABOVE DISCUSSION IT APPEARS THAT A FORMAL AUDIT OR RECONCILIATION PROCESS SHOULD BE USED WITH ANY PCAM. HAS PACIFICORP ADDRESSED THIS ISSUE?**

**A.** No. The Company witnesses provide virtually no explanation of how the PCAM process would actually work. Nor do they even provide a PCAM tariff to define what costs would be included, and which would not. While the Company acknowledges a prudence review would be required, they don't acknowledge any need for an accounting audit to determine whether costs are reasonable ratemaking expenses or eligible for inclusion in the PCAM.

Ordinarily, in states where a permanent PCAM or comparable pass-through mechanism is used, there are detailed rules and procedures that govern the process. For example, Texas fuel cost "reconciliation" cases, where prudence and compliance with the "fuel rule" is verified, are often comparable to a full-blown rate case. Typical "reconciliation" cases take many months to complete, involve dozens of rounds of discovery requests, and often result in hundreds of documents being filed with the Texas commission.[63/]

**Q. WOULD IT BE APPROPRIATE TO IMPLEMENT A PERMANENT PCAM WITHOUT RULES TO GOVERN THE ELIGIBILITY OF COSTS?**

**A.** No. Implementation of a permanent PCAM is a major change in regulatory practice for PacifiCorp. It should not be undertaken without first having a rulemaking or other proceeding to properly define what expenses are eligible for PCAM recovery. This would naturally involve some considerable regulatory activity and, again, would create more, not less, regulatory activity. However, this rulemaking is absolutely necessary if ratepayers are to be protected from paying unreasonable or unverified costs.

**Q. WHAT ELSE WOULD BE REQUIRED BEYOND A "FUEL RULE" TO DEFINE ELIGIBLE COSTS AND APPROPRIATE REGULATORY PROCEDURES TO FAIRLY IMPLEMENT A PCAM?**

**A.** There should also be a set of Minimum Filing Requirements ("MFR"). The MFR should require identification of all long generator outages, generator heat rates, capacities, average fuel costs, monthly listings of purchased power contracts, fuel inventory information, and a variety of other data. PacifiCorp's proposal offers no guidance as to what rules it would propose, the full scope of any review process, or what kind of information it will file when it seeks to change the PCAM.

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[63/] Legislation in Texas did away with pass-through accounting for fuel costs after 2001 for some utilities. However, the final fuel reconciliation for those utilities took until 2004 to complete.

**Q. SHOULDN'T SUCH A RULEMAKING APPLY TO ALL UTILITIES IN THE STATE?**

**A.** Not necessarily. There is a significant difference between PacifiCorp and PSE and Avista. The later two companies now have PCAMs as a result of agreements among the parties. The application of those PCAMs is defined by those agreements. Consequently, rules derived in such a proceeding may not be appropriate to those companies. Because PacifiCorp seeks to implement a PCAM over the objections of ratepayer representatives, instead of with their support, the same standards would not apply in all three cases.

**PCAM Conclusion**

**Q. COULD YOU SUMMARIZE THIS PORTION OF YOUR TESTIMONY?**

**A.** I have identified a number of practical problems with the PCAM proposal that must be addressed. I urge the Commission to reject the PCAM proposal. There are simply too many problems and defects in the PCAM proposal for the Commission to adopt it. However, if the Commission does elect to implement some form of PCAM, significant changes in the Company's proposal and a rulemaking are needed to address the concerns I have identified.

## V. OTHER ISSUES

**WAPA Contract**

**Q. PLEASE EXPLAIN THE WAPA WHEELING RATE ISSUE.**

**A.** This is an issue that arose out of the transmission rate that UP&L charges the WAPA. In the Final Order in Docket No. 99-035-10, the Utah PSC recounted the history of this adjustment:

> In 1962, [UP&L] entered into a fixed-rate contract of 80 years duration with the United States Bureau of Reclamation (later the Western Area Power Administration, WAPA), to wheel Colorado River Storage Project (CRSP) power over the Company's transmission system to public power "preference" customers. Some years later, [UP&L] purchased CP National Corporation's Utah system, and thereby acquired a wheeling contract between CP National and the Bureau of Reclamation, having the same purpose and wheeling rate as the [UP&L] contract. The wheeling rate in these contracts is $4.20 per kilowatt-year; neither permits escalation.
>
> In Docket No. 82-035-13, Report and Order issued May 23, 1983, this Commission recognized that the contracts were not compensatory and ordered an imputation of revenues, based on the then-current Federal Energy Regulatory Commission (FERC) wheeling rate of $24.12, to prevent the subsidy that otherwise would flow from UP&L's retail customers to CRSP preference customers. Revenue imputation for these WAPA contracts has been the Commission's policy since then.[64]

Based on the same order, the Utah Commission determined that the lack of price escalators in an 80-year contract was imprudent. Thus, it imputed revenue to the contract based on the current FERC wheeling rate. The Company has filed its most recent cases in Utah with this as one of its scheduled adjustments.

**Q. HAVE OTHER COMMISSIONS MADE A SIMILAR FINDING?**

**A.** Yes. In Order No. 01-787 in Docket No. UE 116, the Oregon Commission stated as follows:

> We hold that an adjustment needs to be made for the WAPA Wheeling contracts…
>
> It is reasonable to presume from this evidence that by using the Utah formula with the current FERC Wheeling rate, the Oregon adjustment should be $2.0 million. We adopt this amount as the adjustment to be made regarding these wheeling contracts.[65]

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[64] Re PacifiCorp, UPSC Docket No. 99-03T-10, Final Order at 43 (May 24, 2000).
[65] Re PacifiCorp, OPUC Docket No. UE 116, Order No. 01-787 at 37-38 (Sept. 7, 2001).

I recommend the Washington Commission also make this adjustment. Based on PacifiCorp's Response to ICNU DR No. 2.26, application of the Utah formula for this test year would result in an additional disallowance in the amount shown on Table 1.[66/]

**Q. IN PACIFICORP'S RESPONSE TO ICNU DR NO. 2.26, THE COMPANY SUGGESTS THAT IT DISAGREES WITH THIS ADJUSTMENT FOR WASHINGTON IN PART BECAUSE IT ASSERTS IT WOULD BE MORE APPROPRIATE TO REMOVE ALL REVENUES AND COSTS FOR THE CONTRACT. PLEASE COMMENT**.

**A.** In effect, the Company is suggesting that WAPA should be identified as a separate class of service with a specific transmission plant allocated to that customer. Under the logic of the Revised Protocol, which uses a Rolled–in allocation factor for transmission costs, it makes no sense to isolate a single customer. Rather, the cost of the contract would be the average cost of transmission on the system.

If, however, the Commission were to adopt a jurisdictional method for Washington that assigns costs on the basis of a similar premise (i.e., assignment of the historical pre-merger resources to Washington), then I would not disagree with the Company. As a result, I propose this adjustment only if the Commission adopts the Revised Protocol.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

**A.** Yes.

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66/ Exhibit No.___(RJF-12).