Exhibit __ (RJF-RT)
Docket No. UE-020417
Witness: Randall J. Falkenberg

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the petition of PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY For an Accounting Order Authorizing Deferral of Excess Net Power Costs	)))))))))	**Docket No. UE-020417**

REDACTED

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS

OF NORTHWEST UTILITIES

FEBRUARY 4, 2003

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 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 described later in this testimony and in Exhibit __ (RJF-1).

Q. PLEASE BRIEFLY DESCRIBE THE NATURE OF THE CONSULTING SERVICES 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. ICNU has asked me to comment on PacifiCorp's ("PacifiCorp" or the "Company") request for Deferral of Excess Net Power Costs, and its proposal to recover deferred costs via an early termination of the Centralia and Merger credits currently applied to customers bills.

Q. WHAT ARE THE MAJOR CONCLUSIONS AND RECOMMENDATIONS OF YOUR TESTIMONY?

A. My conclusions and recommendations are as follows:

1. PacifiCorp has not met the requirements to re-open the Rate Plan specified in Section 11 of the Stipulation in Docket No. UE-991832. First, the Company is not asking for *similar* relief in Utah and Oregon. Second, application of the six standards of the Pacific Northwest Bell case do not support the relief requested.

2. Rather than facing a financial emergency, PacifiCorp is simply *under-performing*. Its financial results for the most recent fiscal year do not differ substantially from the financial results that were to be expected based on the Rate Plan PacifiCorp agreed to in May 2000.

3. There is no financial emergency at this time. The most recent actual return on equity ("ROE") earned by the Company exceeds the level the Company earned at the time of its request in UE-991832. The Company did not file that case as an interim or "emergency" request.

4. The Commission should reject the Company's projections [redacted] Instead, the Commission should look to recent actual or normalized results. Recent actual data portrays an improving power cost situation, and indicates permanent power costs much lower than projected by the Company. These figures are confirmed by GRID model results.

5. PacifiCorp's representations regarding the rate relief it has been allowed in other states are misleading and not relevant to the requirements of Section 11 of the Rate Plan stipulation. The increases granted by the WUTC in Docket No. UE-991832 were proportionally larger than the contemporaneous increases granted in other states. The baseline net power costs included in rates in Oregon and Utah are comparable to the Washington baseline when comparable load levels are used.

6. Contrary to the testimony of Messrs. Larsen and Widmer, the relief sought by the Company in Washington applies to factors other than the "western power crisis." Indeed, fuel and transmission cost increases (largely due to load growth) are the primary source of increased net power costs. It would be inappropriate and contrary to the Stipulation in Docket No. UE-991832 to provide the Company the relief it requests for costs due to load growth.

7. The deferral mechanism sought by the Company amounts to an implicit request for a "blank check." It could include a potentially unlimited range of costs.

8. The proposal to use the Centralia and Merger credits to provide recovery for the deferred power costs amounts to moving directly from deferral to rate treatment without any intermediate review of prudence, reasonableness or eligibility of deferred costs. It amounts to little more than a request to allow automatic rate treatment of *claimed* costs. This type of procedure has not been used in other states.

9. If the Commission grants the Company the opportunity to defer any power costs, it should narrowly define allowable costs, or substantially modify the PacifiCorp methodology to specifically exclude a variety of inappropriate costs. The

Commission should also consider a sharing mechanism, such as applied in other states.

II. DOCKET NO. UE-991832 STIPULATION ISSUES

Q. SECTION 11 OF THE STIPULATION IN DOCKET NO. UE-991832 CONTAINS LANGUAGE SPECIFYING THE CONDITIONS PRECEDENT TO THE RE-OPENING OF THE RATE PLAN (EXHIBIT __ (JKL-1)). HAS PACIFICORP MET THESE REQUIREMENTS?

A. No. The Company has failed to meet the requirements of the Stipulation on several grounds. Part a., of Section 11 allows a general rate case to be filed if the six standards of the WUTC vs. Pacific Northwest Bell Telephone Company case for interim relief have been met and the Company is requesting *similar relief* in its two largest jurisdictions. Stipulation, Exhibit __ (JKL-1).

The first, and most obvious, problem with the PacifiCorp proposal is that the Company has not filed a general rate case, or even an interim or emergency rate case. Instead, the Company has filed a rate increase proposal that would use deferred costs as a basis for eliminating bill credits resulting from the Centralia gain and Merger savings. In effect, the Company has filed a very abbreviated case that assumes elimination of bill credits is the proper avenue for relief. This is not a general rate case, and thus, is not a permissible re-opener for the Rate Plan.

Q. IS THE COMPANY CURRENTLY REQUESTING ANY *SIMILAR RELIEF* IN ITS TWO LARGEST JURISDICTIONS?

A. No. The Company has no general or interim rate case pending in either Oregon or Utah. It also does not have any application pending that would result in deferral of excess net power costs in Utah for the time period requested here. Thus, it cannot claim to be requesting *similar relief* in those jurisdictions.

Q. WHAT IS YOUR INTERPRETATION OF THIS REQUIREMENT IN THE CONTEXT OF THE RATE PLAN STIPULATION?

A. Allowing the Company to re-open the Rate Plan in the face of a true financial emergency was a reasonable condition of the settlement. ICNU certainly had no intention of preventing the Company from obtaining an emergency rate increase if one were truly needed. If the Company were facing a true financial emergency, then it stands to reason it would be filing for emergency relief in other jurisdictions, particularly its two largest, Oregon and Utah. The fact that the Company is not doing so now belies any assertion that a financial emergency currently exists.

Q. THE COMPANY CONTENDS THAT IT HAS ALREADY REQUESTED RELIEF IN OTHER STATES IN THE PAST. *SEE, E.G.*, EXHIBIT T-__ (JKL-T) AT 7:19-8:7. DOES THIS IMPLY THE COMPANY HAS ALREADY MET THE REQUIREMENTS OF SECTION 11?

A. No, for two reasons. First, if PacifiCorp was ever able to re-open the Rate Plan, it missed the opportunity. In early 2001, the Company filed for emergency relief in Utah and filed for an immediate or interim rate increase in Oregon. The basis for those requests was the Hunter outage and the western power crisis that existed at that time. The Hunter outage has long since passed and the western power crisis has apparently abated. Assuming the Company met the other requirements of Section 11, it *may* have had the opportunity to *request* relief at that time without violating the terms of the agreement. Instead, the Company did nothing. Given that the request for emergency relief was denied in Oregon, and the interim increase allowed in Utah substantially reduced later, perhaps the Company recognized it had a poor case even then. *See* Larsen Direct, Exhibit T-__ (JKL-T) at 8:2.

Q. SECTION 11 OF THE STIPULATION REFERS TO REQUESTING *SIMILAR RELIEF* IN OREGON AND UTAH. HAS THE COMPANY EVER REQUESTED *SIMILAR RELIEF* AS IT REQUESTS HERE?

A. No. The Company is not now, nor has it ever requested *similar relief* in Oregon and Utah. The kind of relief requested (in this case) by the Company differs substantially from anything it previously requested in other states. To my knowledge, the Company has never requested to defer power costs and to recover them via elimination of bill credits in Oregon.

While the final settlement in Utah (in the Hunter and excess power cost deferral cases) did reflect adjustments related to the Merger credits and Centralia gain, that was not part of the Company's original deferral application in November 2000.

Further, the Company is now requesting recovery of substantially different costs incurred at much different times and for very different reasons than those associated with previously requested increases for Oregon and Utah. The relief the Company sought (and to a limited degree obtained) in Oregon and Utah was a result of the western power crisis and the Hunter outage in 2000-2001. The request made by the Company in this case covers a substantially different time period (June 2002 to May 2003), has little to do with the western power crisis, and nothing to do with the Hunter outage. To obtain relief at this time, pursuant to the Stipulation, in Washington, I believe that the Company would have to file requests for recovery of increased costs during the June 2002 to May 2003 time period in both Utah and Oregon.

Q. PLEASE DISCUSS THE COMPANY'S REQUEST IN RELATION TO THE SIX STANDARDS OF THE <u>WUTC V. PACIFIC NORTHWEST BELL TELEPHONE COMPANY</u> CASE.

A. These standards are referenced in Mr. Larsen's testimony. Exhibit T-__ (JKL-T) at 8. The first standard requires that relief be granted only after the opportunity for an "adequate hearing." In this case, the Company has not filed the same depth of information as would be required in a full rate case, even though it is requesting a rate increase. There are a great number of potential issues raised by the Company's application that cannot be addressed in a limited hearing process.

Second, the Company proposes to move directly from the deferral of costs to their ultimate recovery, apparently without any prudence or reasonableness review. In other states where PacifiCorp has deferred power costs (Oregon, Utah and Wyoming), these reviews were a vital step that took place between the deferral of costs and their eventual recovery. In this case, the Company proposes to do away with the review process and move directly to recovery. Thus, the process proposed by the Company does not allow for an adequate hearing.

Q. WHY DOESN'T <u>THIS</u> HEARING PROVIDE THE OPPORTUNITY TO REVIEW THE REASONABLENESS OF THE DEFERRED COSTS?

A. In this proceeding we are dealing only with *projections* of the deferred costs. The actual deferral costs may differ substantially from those estimated at this time. It is impossible to review the reasonableness of costs not yet deferred.

Q. THE SECOND PACIFIC NORTHWEST BELL STANDARD REQUIRES THAT INTERIM RELIEF ONLY BE GRANTED WHEN AN ACTUAL EMERGENCY EXISTS OR RELIEF IS NEEDED TO PREVENT A GROSS INEQUITY. DOES PACIFICORP MEET THIS STANDARD?

A. No. There is no emergency in this case, and the only gross inequity would be if the requested relief were granted.

While I do not dispute that PacifiCorp has not earned a return on equity as high as it would like, under-performance falls far short of an emergency. According to Mr. Larsen's testimony, the Company has earned an ROE on Washington operations of 6.9% for the most recent fiscal year (the twelve months ending on March 31, 2002). Exhibit T-__ (JKL-T) at 9:27-28. While this may be a lower ROE than the Company has *requested* elsewhere, it hardly amounts to an emergency. In fact, this ROE differs little from the level the Company was allowed to earn in 2002, based on the conditions it agreed to in the Stipulation in Docket No. UE-991832, and exceeds the return the Company earned when it filed that case.

Q. PLEASE EXPLAIN.

A. Table 1 presents a calculation of the ROE PacifiCorp agreed to in Docket No. UE-991832. Because the Company agreed to less than its entire requested increase ($25.8 million) it agreed to receive less than the requested 11% ROE. To develop this table, I computed the ROE for each year of the rate plan, based on the figures for the rate case provided by the Company. It presents the returns effectively allowed by the Commission (and accepted by the Company) during the rate plan.

Table 1

Summary of PacifiCorp ROE Per Rate Plan
(Millions)

Year	Per Filing TY	Per Stipulation 2001	2002	2003
Revenues	$185.0	$190.6	$196.3	$198.2
Increase	25.8	$5.6	$5.7	$2.0
Cuml. Inc.		$5.6	$11.3	$13.2
ROE				
Actual TY	5.6	6.8	7.9	8.4
Requested	11.0			

Based on these figures, the Commission allowed (or the Company should have expected to earn) a ROE for 2002 of7.9% based on its rate plan. Instead, for fiscal 2002, the Company earned about a 1% lower ROE as discussed above. I don't believe it constitutes an emergency if the Company earns a ROE 1% lower than allowed by the Commission and/or agreed to by the Company. I certainly don't believe that it would constitute a gross inequity to require the Company to honor its rate plan in this case. Indeed, it would be a gross inequity to re-open the rate plan in these circumstances.

Q. HOW DOES THE MOST RECENTLY EARNED ROE COMPARE TO THAT PACIFICORP WAS EARNING AT THE TIME IT FILED UE-991832?

A. In UE-991832, the Company's filing in 1999 indicated an earned ROE of 5.6%. This is lower than the currently earned return according to Mr. Larsen. Given that UE-991832 was not an emergency request, it stands to reason the current situation is no emergency either.

Q. DOES THE THIRD STANDARD OF THE <u>PACIFIC NORTHWEST BELL</u> CASE APPLY HERE?

A. Yes. The third standard of the <u>Pacific Northwest Bell</u> case holds that the mere failure of the Company to earn its allowed rate of return is not sufficient to grant an interim increase. The table above shows the returns the Company would have been allowed to earn under its rate plan, based on the test year from Docket No. UE-991832. The mere failure of PacifiCorp to achieve these levels (by a small margin) is not sufficient to allow interim relief.

Q. WHAT ABOUT STANDARDS FOUR AND FIVE FROM THE <u>PACIFIC NORTHWEST BELL</u> CASE?

A. These standards discuss issues such as use of interim relief as a tool to stave off impending disaster. In this case, the Company has made no contention of impending disaster. Rather, it suggests {[redacted]} In addition, the Commission indicates it will apply tools such as interim increases with caution. The Company does not represent {[redacted]}

Q. STANDARD NUMBER SIX OF THE <u>PACIFIC NORTHWEST BELL</u> CASE INDICATES THAT THE COMMISSION'S POLICY IS TO REGULATE IN THE PUBLIC INTEREST. HOW DOES THIS STANDARD APPLY IN THIS CASE?

A. I believe that it requires the Commission to set a very high standard of proof before it re-opens a stipulation from a prior case. I urge the Commission to recognize that re-opening a stipulation will have a chilling effect on the entire regulatory process and make it much harder to reach settlements in future cases. Unless parties can be certain that a stipulation will be upheld in future cases, they will be very reluctant to enter into such agreements in the future. In the present case, ICNU is very concerned that

PacifiCorp has attempted to revise the rate plan agreed to by the parties in Docket No. UE-991832. As a result, the public interest is best served by setting a very high standard for the Company to meet before allowing the requested rate increases.

Q. ON THE BASIS OF THESE CONSIDERATIONS, HAS PACIFICORP MET THE STANDARDS REQUIRED TO RE-OPEN THE RATE PLAN?

A. No. On this basis alone, I recommend that the Commission reject the PacifiCorp proposal.

III. PROJECTED VS. ACTUAL AND NORMALIZED POWER COSTS

Q. THE COMPANY HAS PRESENTED SEVERAL PROJECTIONS {[redacted]} DO YOU BELIEVE THE COMMISSION SHOULD CONSIDER THESE PROJECTIONS?

A. No. There is no need for the Commission to consider power cost projections, or their impact on financial results for the period beyond May 31, 2003. The Company is not requesting any sort of relief for that time frame in this proceeding. The deferral requested now would impact financial results until May 31, 2003. After that period, the amortization of the deferrals would likely be offset by increased revenues, thus, eliminating any financial effects. As a result, the financial impact of this relief is limited to the deferral period. However, there is always the danger that once the deferral is granted for the period ending May 31, 2003, the Company may simply renew its request on an on-going basis, creating a state of permanent deferral.

Q. THE PACIFICORP PROJECTIONS PORTRAY {[redacted]}

A. No. However, it is quite speculative as to whether the projected results will actually materialize. If {[redacted]} the

Commission may decide to grant relief consistent with the Rate Plan re-openers specified in Section 11 of the Stipulation, when appropriate.

Q. MR. LARSEN CONTENDS THAT THE COMMISSION SHOULD CONSIDER THE PROJECTED FINANCIAL RESULTS, EVEN THOUGH THEY APPLY ONLY TO THE WASHINGTON OPERATIONS. EXHIBIT T-__ (JKL) AT 10:8-11:19. DO YOU AGREE?

A. No. Mr. Larsen cites a recent California order in support of this premise. However, Mr. Larsen apparently ignores the fact that under Section 11 of the Rate Plan Stipulation, additional relief in Washington is only allowed if similar relief is being requested in Oregon and Utah. This clearly seems to establish a criteria that links relief in Washington to the level of performance in other states. In effect, Section 11 requires that the financial circumstances in other states be sufficiently grave as to require the Company to request relief there as well as in Washington. As a result, it would be contrary to the terms of the Stipulation if "Washington only" results are considered. This is not merely a technicality. The reason ICNU agreed to the terms in Section 11 was to allow the Company relief if a true emergency existed throughout the system, not simply under-performance in one state.

Q. ARE THERE OTHER REASONS WHY THE COMMISSION SHOULD IGNORE THE COMPANY'S PROJECTED POWER COSTS?

A. Yes. If this is to be a de facto single-issue rate case, the Commission should base its review on a *normalized historical test year*, as is customary for ratemaking in Washington. In Docket No. UE-991832, for example, the Company used a 1998 test year adjusted for known and measurable changes to June 2001. The Commission should not adopt projected power costs for future periods as the basis for any review of PacifiCorp's circumstances.

In addition, the projected power costs prepared by the Company were developed from budget data, not from one of the Company's power cost models, such as GRID or PD-Mac. To my knowledge, the Company has not used the budget projections as the basis for power cost normalization studies in *any* of its recent cases in California, Oregon, Utah or Wyoming. The budget data is not necessarily developed for the same purposes, or with the same concepts, as the rate case data. There is no assurance that this approach will be acceptable for ratemaking purposes. The Commission should reject the PacifiCorp filing on this basis alone.

Q. DO YOU HAVE ANY EVIDENCE TO DEMONSTRATE THAT THE PACIFICORP NET POWER COST PROJECTIONS ARE NOT USEFUL FOR THIS PROCEEDING?

A. Yes. First of all, the projections presented by the Company by themselves invite the Commission to again violate the terms of the Stipulation in Docket No. UE-991832. The Company proposes to change the *sales levels* used in computing power costs from those used in developing current rates. This is not allowed under the terms of the Stipulation:

> The Company's present revenues and billing determinants from the 12 months ending December 31, 1998 will be used in setting rate changes during the Rate Plan Period and implementing rate design changes.

Exhibit __ JKL-1 at 3.

This appears to be an <u>absolute requirement</u>, with no "re-opener" allowing the Company to waive this clause of the Stipulation.

Q. WHY IS THIS IMPORTANT?

A. A major cause of the changes in power costs projected by the Company is an assumed change in loads. However, use of the changed loads, without reflecting the changes to underlying billing determinants (i.e., kWh sales) creates a mismatch between costs and loads. The basic problem is that the Company proposal would not reflect changes in sales revenue, but only changes in costs.

Actual loads have *increased* from the levels assumed in Docket No. UE-991832. However, if loads are increasing, then sales revenues increase as well. Increasing sales by themselves should result in a reduction in the average cost per kWh for fixed costs. Thus, in addition to violating the terms of the settlement, the Company proposal is one-sided. As a result, the Commission should only consider power cost analyses that are consistent with the test year loads used in Docket No. UE-991832.

This is a fundamental problem in the PacifiCorp approach. The Company would increase rates to reflect the cost of increased loads, but not reflect the increases in sales in resetting base rates. This provides yet one more reason why the Stipulation only allows a re-opener in the form of a *complete rate case filing*, rather than a one-sided "partial" rate case as proposed by the Company. Unless a complete test year and rate case is filed (based on the load levels used in UE-991832), there is no basis for comparing revenues with expenses that are based on differing sales levels. Nor is it equitable to make rate adjustments on the basis of increased costs accompanying load growth, while the rates themselves do not consider this load growth.

Q. HOW DO THE DOCKET NO. UE-991832 TEST YEAR LOADS COMPARE WITH THOSE USED IN THE COMPANY'S PROJECTED POWER COSTS FOR THE PERIOD JUNE 1, 2002 TO MAY 31, 2003?

A. {[redacted]}.

Q. DO YOU HAVE ANY EVIDENCE THAT DEMONSTRATES THE UNRELIABLE NATURE OF THE COMPANY'S PROJECTED POWER COSTS?

A. Yes. A review of the most recent *actual* data raises serious questions about the Company's projected power costs. Exhibit __ (RJF-2) shows the trend in net power costs based on the 12 months ending January through October 2002. The results contain five of the twelve months contained in the Company's budget projection for the period June 2002 to May 2003.

Exhibit __ (RJF-2) shows that without any adjustments, actual power costs for the most recent 12-month period (November 2001 to October 2002) were $685.9 million. In contrast, {[redacted]}

Thus, {[redacted]}. Indeed, the Company is experiencing a *downward* trend in power costs as the residual effects of the western power crisis are working their way out of the Company's cost structure. *See* again Exhibit __ (RJF-2) which shows the 12 months ending power costs from the start of the year.

Q. HOW DO THE COMPANY'S PROJECTED LOADS COMPARE WITH ACTUAL AND WEATHER NORMALIZED ACTUAL LOADS FOR THE MOST RECENT TWELVE MONTHS?

A. [redacted]

Q. ARE THERE ANY OTHER REASONS TO REJECT THE COMPANY'S PROJECTED POWER COST STUDY?

A. Yes. Because the study is based on projected data, it may not contain all of the types of adjustments typically made by regulators. It would be unwise to assume the Company has made a complete series of adjustments for ratemaking purposes. Indeed, PacifiCorp's recent rate cases have seen a host of hotly debated power cost issues.

Q. HAVE YOU DEVELOPED A NORMALIZED ACTUAL POWER COST STUDY?

A. Yes. Exhibit __ (RJF-3a) presents a normalized power cost study based on actual results for the twelve months ending October 2002. It includes a series of adjustments to actual that would reflect ordinary ratemaking adjustments. While this is intended as a reasonable and illustrative analysis, it is not intended as an exhaustive analysis of normalized power costs.

Q. WHAT ARE THE ADJUSTMENTS TO ACTUAL THAT YOU HAVE DEVELOPED?

A. First, I removed the effects of the actual increases in sales to match the load levels used in Docket No. UE-991832. Second, I adjusted to normal hydro conditions based on the UE-991832 Test Year. I also reversed the increase in wheeling expense, based on the assumption that most of this increase is due to increased load and the need to purchase power to compensate for the hydro deficit. I also made an upwards adjustment to wheeling revenues for a imprudent contract with WAPA. Next, I made revenue adjustments for the Sacramento Municipal Utility District ("SMUD") contract, to impute additional revenue. This is consistent with the treatment afforded SMUD in other jurisdictions. I then removed the revenue and expense effects of contracts terminating between June 2002 and May 2003 from the analysis ("one time costs"). I also imputed a full year of operation to the Gadsby CT, because it will have operated for nearly the entire period from June 2002 to May 2003. I also made an adjustment to remove half of the Colstrip generation from the Test Year because it has not been included in the Washington rate base in the past. Finally, I removed excess costs related to the Little Mountain CT, because it is detrimental to ratepayers.

Q. DOES THIS PROVIDE A COMPLETE ANALYSIS OF POSSIBLE RATE CASE ADJUSTMENTS?

A. No. It only provides a high level review of possible power cost adjustments. A full rate case would use a power cost model, such as GRID or PD-Mac and would allow for a much more detailed analysis. However, experience from recent cases has shown that normalized results do not usually depart substantially from actual power costs, once comparable adjustments are made.

Q. IS IT APPROPRIATE TO REMOVE THE ONE-TIME COSTS FROM THIS ANALYSIS?

A. Yes. Ordinarily, for ratemaking purposes, one would only consider permanent costs. Were this a typical rate case, there might be a discussion about how or if such costs could be recovered. This would also depend on Commission precedents and policy decisions related to recovery of such costs. However, because we are dealing with re-opening the Rate Plan, I believe one-time costs should be excluded from the review. As I stated earlier, the Commission should set a very high standard for providing relief in this case. The presence of non-recurring or one-time costs should not be the basis for re-opening the Rate Plan

Q. ARE THERE OTHER ADJUSTMENTS THAT MAY NEED TO BE MADE TO DEVELOP NORMALIZED NET POWER COSTS?

A. As discussed earlier, it is not possible to tell without a complete rate filing. There could be a number of other issues requiring analysis.

Q. WHAT ARE THE RESULTS OF THIS ANALYIS?

A. Exhibit __ (RJF-3a) shows that based on this analysis, the normalized power costs based on the most recent, normalized net power costs for PacifiCorp are $499 million. This is only about 2.5% more than already included in rates. This level of cost is not so substantially different from those already included in Washington rates as to suggest a need to re-open the Rate Plan.

Q. HAVE YOU ANALYZED ANY GRID MODEL RUNS TO CORROBORATE YOUR NORMALIZATION RESULTS?

A. Yes. In discovery, I obtained a GRID model study based on the UE-134 (Oregon) test year, with certain adjustments made by the Company to conform it to the Washington test year. The results of this study, once adjusted for removal of one-time costs, abnormal thermal outages and other typical ratemaking adjustments are quite similar to those of the normalized actual results. Exhibit __ (RJF-3b) summarizes this study.

Q. {[redacted]} In Oregon Docket No. UE 134, the Company agreed to a settlement containing a net power cost baseline of $589 million for a test year ending June 2003. In Utah, in Docket No. 01-035-01, the Company was awarded $589 million in net power costs on a total Company basis, for the test year ending September 2000.[1/] Further, I believe that most of the remaining difference between power cost baselines in Oregon and Utah and the current level embedded in Washington rates is due to load growth.

Q. PLEASE EXPLAIN.

A. Exhibit __ (RJF-4) summarizes the net power costs for the Oregon and Utah test years, after adjustment for changes in load levels. In Oregon, test year loads from UE-134 (which were in turn based on UE-116 load levels) exceed the Washington test year loads by 5.7%. In Utah, loads for the most recent case (Docket No. 01-035-10) exceeded the Washington test year loads by slightly more than 5%. Once adjusted for this difference in loads, the total net power costs for both states differ little from the $487 million level included in Washington rates. The Oregon power costs adjusted to Washington load levels is $524 million. For Utah the result is $489 million.

Q. IS IT "UNFAIR" THAT THE HIGHER LOADS REFLECTED IN RATES OF OTHER STATES ARE NOT ALSO REFLECTED IN WASHINGTON?

A. Not at all. Recall that in both Oregon and Utah, the loads have also been reflected in billing units. Higher billing units equate to a lower average cost per kWh because fixed costs are spread over more sales. Thus, there is a match between sales levels, billing units and power costs in all three states. In addition, both the Oregon and Utah test year

---

[1/] "Actual system net power costs in 1997 and 1998 totaled $370 million and $445 million respectively. For the test year, October 1999 to September 2000, actual net power costs totaled $620 million, an increase of nearly $175 million, or approximately 39.5 percent, relative to 1998. While fuel and wheeling expenses decreased in the test year relative to 1998, it is the larger increase in purchased power expense relative to the smaller increase in sales for resale revenue that accounts for the overall increase in actual net power costs in the test year relative to 1998. For comparison purposes, the amount of net power costs included in rates as a consequence of the last two general rate cases, Docket Nos. 97-035-01 and 99-035-10, are also shown in the table above. Net power costs, as adjusted by our decisions, totaled $589 million for the test year, October 1999 to September 2000." Utah Public Service Commission, Docket No. 01-035-01, Order and Report: September 10, 2001, page 35.

loads were based on actual data developed *prior* to September 11, 2001 and don't reflect the effects of the current economic recession.[2/] Actual (and weather normalized) loads for the most recent 12 months are actually *lower* than the loads used in the Oregon and Utah test years. Thus, the current level of sales reflected in Washington base rates is not unrealistic vis-à-vis other states. If anything, the loads used in the other states may now be too high.

Q. MR. LARSEN CONTENDS (PAGE 16, LINES 14-19) THAT THE COMPANY HAS RECEIVED RATE INCREASES IN UTAH AND OREGON SINCE THE MAY 2000 SETTLEMENT IN DOCKET NO. UE-991832. HE TESTIFIES ON PAGE 17 LINES 13-14 THAT THIS RELIEF SUGGESTS THAT WASHINGTON RATEPAYERS ARE NOT PAYING THEIR FAIR SHARE. DO YOU AGREE?

A. No. However, this issue has only a limited bearing on the question of allowing relief in Washington under the Company proposal. The Stipulation most certainly does not allow re-opening the rate plan on the basis of any claim of inequality among the states.

Nonetheless**,** I don't believe the 2001 rate awards in Utah or Oregon are compelling evidence that Washington ratepayers are paying less than an equitable share. To illustrate why, it is necessary to recall the history of PacifiCorp rate proceedings over recent years.

In late 1999 and early 2000, the Company filed for increases in Oregon, Utah and Washington. In Utah, the case was fully litigated, and in Oregon and Washington settlements were reached. In Utah, the Company received a $17 million increase in May 2000. In Oregon, the Company received a $13.6 million increase in September 2000. At

[2/] The Utah loads are based on actual data for the twelve months ending September 30, 2000. The Oregon loads were based on the figures used in UE-116, the 2001 rate case, filed in late 2000.

the same time, the Company agreed to the Rate Plan in Washington that would allow total rate increases of approximately $13.3 million overall. Considering that Washington is a much smaller portion of the system than either Oregon or Utah, obtaining a settlement that allowed nearly the same ultimate level of rate increases as the two larger states suggests that Washington ratepayers were providing substantial relief to the Company at that time. In fact, the Washington increases were proportionally larger than those experienced by customers in Oregon on Utah.

Q. WHAT WERE THE REASONS FOR THIS?

A. There were both technical and practical reasons for the differences in the outcomes between the states. A very important difference was that Washington allowed use of a test year that reflected known and measurable changes into 2001. In Utah, a much more strict historical test year is used. A major factor included in the Washington case not reflected in Utah at that time was the looming sale of the Centralia plant. This resulted in higher normalized power costs for Washington than Utah. It turns out that the sale of Centralia was also a major factor in PacifiCorp's subsequent increases in power costs during the western power crisis. This issue had to be dealt with in Utah in later cases.

In addition, the Washington rate plan allowed for scheduled increases over several years. This afforded the Company more assurance about future revenues than the cases in other states. At the same time, the Company avoided the costs and difficulties of filing a case in a relatively small state.

Q. PLEASE DISCUSS THE SUBSEQUENT CASES FILED IN 2001.

A. In 2001, the Company filed several more cases in other states, but did not file any request for an increase in Washington. Based on the 2000 Utah rate order, it is fair to conclude the Company needed an increase in Utah simply to achieve the same level of net power costs that were already allowed in rates in Washington. While the Utah test year from the 2000 case contained net power costs of approximately $421 million (and an overall allocation to the state of 34.9%), the Company's Washington filing used net power costs of $487 million.

However, by the time of the 2001 case, Utah's allocation of net power cost increased to 36.9%. Therefore, it would have taken an increase of approximately $33 million to simply *match* Washington's allowed power costs.[3/] Given that Utah allowed only a $40.6 million increase in the 2001 case, it should be rather apparent that most of this increase was needed to simply bring Utah up to the level of power costs already allowed in Washington and to reflect the increase in the jurisdictional allocation factor.

The Utah Commission allowed level of net power costs ($589.3 million) in 2001 resulted in an increase in power cost recovery assigned to Utah of approximately $70 million. Thus, the permanent increase actually granted in Utah ($40.6 million) was substantially less than the amount of increases in power costs assigned to that state. The implication from all of this is that the increase in Utah rates was smaller than the increase in power costs. This suggests that other costs were declining and/or the increase in sales produced substantial revenue increases as well. This is why a full rate case would be needed to equitably address the issues of increases in power costs. It is simply incorrect for the Company to suggest that the absence of a rate increase in Washington in 2001

3/ (487times.369-421times.349) = $32.8

demonstrates that ratepayers in other states are bearing a disproportionate share of system costs.

In addition, given the increased allocation of power costs to Utah, it stands to reason that other states (including Washington) would see a *decrease* in the percentage allocation of net power costs.[4/] As a result, it is not reasonable to assume that increased power costs at the system level will translate directly or proportionally to an increase in revenue requirements allocated to Washington. Indeed, as shown above, the overall rate increase granted in Utah was substantially less than the amount of increased power costs the Utah Commission assigned to that state. All of this indicates that it would be necessary to have a complete rate case to sort out all of these issues.

Q. MR. LARSEN ALSO TESTIFIES CONCERNING THE RATE RELIEF ALLOWED IN OREGON AND UTAH RELATED TO COSTS ASSOCIATED WITH THE HUNTER OUTAGE AND THE WESTERN POWER CRISIS. DO YOU AGREE THAT WASHINGTON HAS NOT BEEN ASSIGNED ANY OF THESE COSTS?

A. Yes. However, as discussed above, the opportunity to recover those costs has passed. Whether the Company *might* have obtained treatment for these costs given a timely filing in the past is an unresolved question. However, this is not a reasonable basis for providing prospective relief for other costs at this time.

Further, the Company's discussion of these temporary increases is quite misleading. Mr. Larsen testifies that the Company was allowed a $70 million interim increase in Utah. Exhibit T-__ (JKL-T) at 7:23. However, of this increase, only $40

4/ Please note that this increase is not due to any change in methodology for assigning costs between jurisdictions. It merely reflects assumed load growth.

million was a permanent increase, and the remaining amounts are being used to offset power costs deferred due to the Hunter outage and purchases made during the western power crisis. Likewise, the amortization of $130 million in Oregon, referenced by Mr. Larsen on page 8, line 6, is related to the Hunter outage and deferred power costs during the power crisis. *See also* Widmer Direct, Exhibit T-__ (MTW-T) at 6:14-7:5. In neither case do these recoveries relate to current costs, or to costs similar to those being requested in this case. Indeed, the time periods being considered are different. In both the Oregon and Utah cases, these deferrals reflected the period November 2000 to September 2001. The deferral period requested by the Company in this case is June 2002 to May 2003. Thus, the requests granted in other states were not for "similar rate relief" under the terms of the Stipulation.

Q. MR. WIDMER TESTIFIES THAT THE EFFECTS OF THE WESTERN POWER CRISIS IN 2000 – 2001 ARE INCLUDED IN THE DEFERRAL PERIOD. EXHIBIT T-__ (MTW-T) AT 5:3-11. IS THIS CORRECT?

A. The only basis for this contention is that some of the purchased power contracts included in the deferral period were negotiated during the power crisis. However, I believe this amounts to only $49-$56 million (total Company basis) for the deferral period. This would equate to approximately $5 million for Washington of the estimated $17.5 million deferral. Exhibit T-__ (JKL-T) at 19:20. As a result, the remaining deferral is related to cost increases that post-date the power crisis. As discussed above, it appears these increases are largely related to load growth that has been occurring.

Recovery for these high cost contracts has never been requested in Utah. Thus, the Company cannot claim the deferral temporary rate increase allowed in Utah amounts to a request for "similar rate relief."[5]

Q. IF NET POWER COST INCREASES ARE NOT DUE TO THE WESTERN POWER CRISIS, THEN WHAT IS THEIR SOURCE?

A. As discussed above, the primary source of increased power costs is load growth, a variety of non-recurring costs (some of which were contracted for during the time of the power crisis), fuel cost increases and transmission cost increases. I believe that to a large extent the fuel cost increases are really load related because the Company has found it necessary to install new peaking plants primarily to meet load growth. The operation of these resources causes fuel costs to increase. As discussed above, it would be inappropriate to allow recovery of these costs so long as base rates in Washington are based on a much lower level of billing determinants.

IV. THE PACIFICORP DEFERRAL MECHANISM IS FLAWED

Q. LET'S TURN NOW TO THE MECHANICS OF THE PACIFICORP PROPOSAL. DO YOU SEE ANY PROBLEMS WITH THE REQUESTED DEFERRAL MECHANISM?

A. Yes. While mechanically a simple computation, the PacifiCorp approach really amounts to a request for a "blank check." The Company would be able to defer a very wide variety of costs based on the proposed mechanism. I have been involved in cases in Utah, Wyoming and Oregon where the Company's deferral proposal has been used. I

---

[5] The Company is currently being allowed to amortize these costs on a one-year basis in Oregon, and has requested recovery of these costs in Wyoming. However, in neither of these cases is the relief requested or allowed similar to that which is requested here. In Wyoming the Company has requested a general rate increase, while in Oregon, the Company is recovering the costs through current rates.

believe that there are a number of problems with this approach that are not immediately apparent. Many of these problems have led to regulatory conflict in the other states.

Q. PLEASE DESCRIBE THESE PROBLEMS.

A. First, the deferral requested is extremely broad and non-specific. It does not apply to any particular costs, such as expenditures for equipment, repair costs, or a new tax. Rather, the Company proposal covers a large class of costs, as compared to the level allowed in rates. While the Company characterizes its deferral as "excess net power costs," it would differ little from allowing the Company to defer a return on equity shortfall. I have never heard of a regulator allowing a deferral for a return on equity shortfall.

Ironically, a return on equity shortfall deferral might be less onerous to ratepayers because it would presumably limit the deferral to only those cases where an allowed ROE is not achieved. Under the Company proposal, there is no mechanism to prevent the Company from deferring power costs to such an extent that it could recover excess of its allowed (or agreed upon) rate of return.

Q. WHAT KINDS OF COSTS MIGHT BE DEFERRED PURSUANT TO THE REQUESTED DEFERRAL ORDER?

A. There are a wide variety of potential costs. Costs associated with load growth, for example, would be deferred automatically under the Company proposal. In addition, costs due to increases in fuel or transmission expenses (prudent or not) would be deferred, as would unexpected increases in purchased power expenses or declines in sales revenues. The same would be true of shortfalls for poor hydro conditions, even though base rates already contain normalized power costs reflecting a broad range of hydro levels.

In recent cases the Company has even agreed to eliminate certain costs it included in its initial deferral calculation. Such deductions were related to imprudence (costs related to the Cheyenne contract extension), lack of reasonableness (as in the SMUD contract), and costs that were simply not eligible even under the Company deferral (such as the combustion turbine rental fees). The Company has proposed no methodology for separating out allowable costs from those not allowable in this case.

In addition, costs for major plant outages, such as Hunter, might be considered as allowed under the heading of "excess power costs."[6/] Under the Company proposal, mere deferral of this kind of cost would provide for ultimate recovery.

Another problem would be that of conforming costs to standard ratemaking treatments. This is a complicated problem in this case because the settlement in Docket No. UE-991832 was a "black box." It would be necessary for the Commission to make a determination of the kinds of ratemaking treatments it would expect to be made to actual costs, when comparing those to normalized costs "in rates."

Finally, costs for new plants might also be included in the Company deferral request. This could include the costs of the West Valley combustion turbine, for example. The Commission would effectively lose the opportunity to review the prudence of new resources under the Company's proposal.

6/ This has been a source of major controversy in other states. In Wyoming, for example, parties have disagreed about whether an identical deferral mechanism allows major plant outages.

Q. WHAT OTHER KINDS OF PROBLEMS MIGHT RESULT FROM THIS PROPOSAL?

A. Essentially, any cost that the Company decides to book as a power cost could be deferred in the Company proposal. There are obvious questions this proposal raises concerning the propriety of accounting entries. However, there are less obvious questions the Commission should consider. For example, based on the method applied by the Company in other states, costs for load management curtailments would be included, as would costs associated with buyouts of contracts. Would the Commission agree to recovery of such costs for these purposes? If the Company entered into a contract to purchase interruptions from a large customer at a very high price, it might decide to defer these costs. Would the Commission agree that this was a beneficial arrangement or merely a "sweet-heart" deal in disguise? Under the Company proposal, issues such as this would apparently be resolved based on the "honor system."

Q. WHAT OTHER PROBLEMS EXIST IN THE COMPANY PROPOSAL?

A. If the PacifiCorp plan is accepted, the Commission would be allowing the Company to move directly from deferral to rate recovery, by amortizing the deferred costs against the Merger and Centralia sale credits. This would amount to a step other states have simply refused to allow. In Oregon, Utah and Wyoming, the deferral of costs during the western power crisis was allowed. However, proceedings were conducted that allowed for recovery of those costs. Only *after* an opportunity for a thorough review of prudence, reasonableness and eligibility of the deferred costs was allowed did rate recovery follow. In both Wyoming and Oregon, these issues were fully litigated before their respective

Commissions. In all three of these states, the analysis of these deferred costs has been quite complex and difficult.[7/]

Q. ACCORDING TO MR. LARSEN, SECTION 9 OF THE STIPULATION ALLOWS THE COMPANY TO REQUEST ACCOUNTING ORDERS FOR DEFERRALS. DO YOU AGREE?

A. The language of Section 9 does allow deferrals. However, it does not specifically allow recovery of these costs during the Rate Plan period. After termination of the Rate Plan period, the Company is also required to justify the level of rates that exist. It appears the Company could request recovery of deferred items at that time. However, ultimate recovery of deferrals is not assured.[8/]

In addition, the language of Section 9 clearly states that the Company is not prohibited from "submitting petitions for accounting orders, as appropriate." Stipulation, Exhibit __ (JKL-1) at 7. However, this does not mean that the Commission is obligated to authorize accounting orders, particularly in a case like this where the relief requested is so wholly inappropriate.

Q. ASSUMING THE COMMISSION DOES GRANT SOME ACCOUNTING ORDER FOR DEFERRED COSTS, WHAT WOULD YOU RECOMMEND?

A. In that case the Commission should either extensively modify the PacifiCorp proposal, or limit deferral to a set of specific costs.

7/ I believe that a settlement was only possible in Utah because the Company agreed to limit the deferral for much of the period during the power crisis to the costs specifically related to the Hunter outage. This substantially simplified the process.

8/ Subsequent recovery of costs deferred during the Rate Plan period would really amount to the same thing as an increase in rates during the deferral period. This would only be allowed if the Company meets the requirements of Section 11 of the Rate Plan Stipulation.

If the Commission opts for the latter treatment, it should first identify the costs it considers allowable for deferral. An example might be the summer 2002 above market purchase contracts. In that case, the Commission should define the methodology used for computing the deferral (i.e., the difference between contract price and market value). The Commission should also place limits on recoverability of those costs. For example, no recovery should be allowed if it results in the Company earning a rate of return above the levels allowed in Docket No. UE-991832.

Q. ASSUMING THE COMMISSION DESIRES A MORE COMPREHENSIVE ALTERNATIVE, WHAT SUGGESTIONS CAN YOU OFFER IN TERMS OF CORRECTING THE PACIFICORP METHODOLOGY?

A. The Commission should only accept a methodology that eliminates the impact of load growth, unusual plant outages, imprudent or unreasonable costs, and perhaps the cost of new plants not certified by the Commission. A deferral case should not become the venue for determination of the prudence of a new plant, for example. In addition, the mechanism should allow for some PacifiCorp sharing of increased power costs as was done in cases in other states.

In the end, if the Commission does grant the Company a deferral mechanism similar to that requested, it must allow for a lengthy and likely contentious review of those costs before allowing any ultimate rate treatment. Because PacifiCorp's proposal has so many flaws, I have not taken the time to quantify all of the power cost adjustments that must be made to establish an appropriate level of recovery. It is essential that this step occur and PacifiCorp not be given the blank check it is requesting here. For all the reasons detailed above, I recommend that the Commission simply deny the request put forth by the Company at this time.

V. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. Exhibit __ (RJF-1) describes my education and experience within the utility industry. I have more than 20 years of experience in the industry. I have worked for utilities, both as an employee and as a consultant, plus as a consultant to major corporations, state and federal governmental agencies, and public service commissions. I have been directly involved in a large number of rate cases and regulatory proceedings concerning the economics, rate treatment, and prudence of nuclear and non-nuclear power plants.

During my employment with EBASCO Services in the late 1970s, I developed probabilistic production cost and reliability models used in studies for 20 utilities. I personally directed a number of marginal and avoided cost studies performed for compliance with the Public Utility Regulatory Policies Act of 1978 (“PURPA”). I also participated in a wide variety of consulting projects in the rate, planning, and forecasting areas.

In 1982, I accepted the position of Senior Consultant with Energy Management Associates (“EMA”). At EMA, I trained and consulted with planners and financial analysts at several utilities using the PROMOD III and PROSCREEN II planning models.

In 1984, I was a founder of J. Kennedy and Associates, Inc. (“Kennedy”). At that firm, I was responsible for consulting engagements in the areas of generation planning, reliability analysis, market price forecasting, stranded cost evaluation, and the rate treatment of new capacity additions. I presented expert testimony on these and other matters in more than 100 cases before the Federal Energy Regulatory Commission

("FERC") and state regulatory commissions and courts in Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Louisiana, Maryland, Michigan, Minnesota, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Texas, Utah, West Virginia and Wyoming. Included in Exhibit __ (RJF-1) is a list of my appearances.

In January 2000, I founded RFI Consulting, Inc., with a comparable practice to the one I directed at Kennedy.

Q. HAVE YOU PREVIOUSLY PARTICIPATED IN ANY PROCEEDINGS CONDUCTED BY THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION?

A. Yes. I analyzed net power cost issues for ICNU in Docket No. UE-991832. As the Commission is well aware, that case was settled prior to the time when ICNU might have filed its direct testimony.

Q. HAVE YOU APPEARED AS AN EXPERT IN OTHER PROCEEDINGS INVOLVING PACIFICORP?

A. Yes. I have been involved in a number of PacifiCorp proceedings in California, Oregon, Utah and Wyoming, where I testified concerning power cost issues.

I appeared in PacifiCorp's last three Utah general rate proceedings. In PacifiCorp Docket No. 97-035-01, I testified in support of the Net Power Cost Stipulation ("1997 Stipulation") on behalf of the Utah Division of Public Utilities ("DPU") and the Committee of Consumer Services ("CCS"). The 1997 Stipulation included most of the modeling and data input adjustments that I recommended. In that case, the Stipulation was the culmination of an intensive audit I performed of the Company's net power cost model, PD-Mac.

I appeared again as a witness for the CCS in PacifiCorp's 2000 Utah rate proceeding, Docket No. 99-035-10, where I addressed net power cost issues. In the final order in that proceeding, the Utah Public Service Commission accepted all of my proposed net power cost adjustments, which totaled approximately $18 million (PacifiCorp system-wide). In August 2001, I testified in PacifiCorp's most recent Utah general rate proceeding, Docket No. 01-035-10.

I also appeared in the Gadsby Combustion Turbine ("CT") Certification case in Utah (Docket No. 01-035-37) and in the combined Utah Excess Power Cost and Hunter Outage Proceeding (Docket Nos. 01-035-23, 01-035-29 and 01-035-36).

I filed testimony in PacifiCorp's last two full rate proceedings in Oregon (Docket Nos. UE-111 and UE-116). Both cases were ultimately settled on the issues I addressed. UE-111 used a test year that was very comparable to that used in Docket No. UE-991832 in Washington for net power costs. In those cases, I addressed issues related to modeling of net power costs, and a Power Cost Adjustment ("PCA") mechanism. I also filed testimony in PacifiCorp Docket No. UM-995, quantifying the disallowances proposed by other ICNU witnesses and the costs of the hydro energy deficit experienced by the Company. I recently filed testimony related to the West Valley Combustion Turbine lease in Oregon Docket No. UE-134.

In late 2001, I filed testimony in the PacifiCorp Wyoming cases concerning a purchased power adjustment clause and deferral of excess power costs. (Docket Nos. 20000-ER-167 and 20000-EP-160). These cases were subsequently withdrawn by

PacifiCorp. In November 2002, I filed testimony in Wyoming Docket No. 20000-EP-02-184 concerning net power costs and deferred power costs.

In July 2001, I filed testimony in the PacifiCorp rate proceeding in California (Application 01-03-026). In these recent California, Oregon and Utah rate proceedings, my testimony concerned net power cost modeling issues and excess net power costs. Exhibit __ (RJF-1) summarizes all other cases in which I have appeared.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.