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October 17, 2005

Via Electronic and US Mail

Public Utility Commission of Oregon
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PACIFIC POWER & LIGHT Application for Power Cost Adjustment Mechanism
Docket No. UE 173

Dear Filing Center:

Enclosed please find an original and six copies of the Supplemental Testimony of Randall J. Falkenberg and of Michael Gorman on behalf of the Industrial Customers of Northwest Utilities in the above-captioned proceeding.

Please return one file-stamped copy of the document in the self-addressed, stamped envelope provided.

Thank you for your assistance.

Sincerely,

/s/ Anna E. Studenny
Anna E. Studenny

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Supplemental Testimony on behalf of the Industrial Customers of Northwest Utilities upon the parties, on the service list shown below, by causing the same to be mailed, postage-prepaid, through the U.S. Mail.

Dated at Portland, Oregon, this 17th Day of October, 2005.

/s/ Anna E. Studenny
Anna E. Studenny

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 173

In the Matter of	)
	)
PACIFICORP	)
	)
Application for Approval of Power Cost	)
Adjustment Mechanism.	)

POWER COST ADJUSTMENT MECHANISM

SUPPLEMENTAL TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

October 17, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350. I am the same Randall J. Falkenberg who filed direct testimony in this case.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The first part of this testimony is to respond to the recommendations made by Oregon Public Utility Commission ("OPUC" or the "Commission") Staff in its direct testimony regarding PacifiCorp's (or the "Company") request for approval of a power cost adjustment mechanism ("PCAM"). The second part of this testimony discusses the implications of the Commission's final order in Docket No. UE 170, as it relates to the issue of a PCAM for PacifiCorp.

Q. PLEASE STATE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. My conclusions and recommendations are as follows:

1. While I generally agree with Staff's general comments concerning the revenue neutrality, deadbands, sharing bands and risk shifting as they relate to the PCAM, I strongly disagree with Staff's proposal for an interim PCAM retroactive to February 2005. I recommend the Commission reject the Staff proposal.

2. The Staff interim PCAM allows recovery of excess power costs starting in February 2005. This would result in retroactive ratemaking because only hydro deficit costs, not excess power costs, were deferred in PacifiCorp's application in UM 1193.

3. In UE 170 the Commission adopted PacifiCorp's Transition Adjustment Mechanism that included an annual Resource Valuation Mechanism ("TAM"). This eliminates much of the need for a PCAM. I recommend the Commission reject PacifiCorp's proposed PCAM as well.

1. STAFF REBUTTAL TESTIMONY

Q. PLEASE BEGIN YOUR DISCUSSION OF THE STAFF TESTIMONY.

A. I agree with Staff's recommendation to reject PacifiCorp's PCAM proposal; however, I disagree with Staff's proposal that the Commission establish an interim PCAM for PacifiCorp in 2005 and 2006, and a comprehensive, permanent PCAM after that time. Consequently, this testimony will delineate and explain the areas of disagreement with Staff.

Q. IN THE INTEREST OF CLARITY, COULD YOU IDENTIFY YOUR AREAS OF AGREEMENT AND DISAGREEMENT WITH STAFF?

A. Yes. I agree with many of Staff's comments and recommendations regarding the PacifiCorp PCAM proposal itself. However, I disagree with Staff's recommendation to implement an "interim" PCAM retroactively to February 1, 2005. Staff argues that the deferral application in UM 1193 allows the PCAM to be implemented retroactively. I am troubled by Staff's proposal to broaden the scope of costs eligible for recovery far beyond PacifiCorp's limited request for deferral of hydro costs in UM 1193. To be as specific as possible, below I present a grouping of Staff's recommendations to the Commission. After each set of recommendations, I will indicate whether I agree or disagree with the set of recommendations.

<u>Staff Recommendation # 1</u>

- *The Commission should consider reasonable risk reduction, neutral cost recovery, and equal treatment criteria when evaluating automatic adjustment clauses.*
- *The Commission should reject PacifiCorp's proposed PCAM. The proposed sharing bands remove nearly all of PacifiCorp's earnings risk related to variation in net variable power costs*

> *("NVPC") and fails the reasonable risk reduction criterion. Tracking asymmetric financial impacts with the symmetrically designed PCAM would result in an expected economic windfall for PacifiCorp and therefore fails the neutral cost recovery criterion.*
>
> - *The Commission should indicate a preference for Expected Value Power Cost modeling. Modeling the uncertainty associated with retail loads, natural gas and electricity market prices, hydroelectric generation, and thermal unit availability provides a more realistic simulation of PacifiCorp's system operations and produces a distribution of NVPC that can be used to design a fair PCA mechanism.*

Staff/100, Galbraith/2. I agree with these statements.

Mr. Galbraith then makes a number of other recommendations that speak to implementation of Staff's interim and permanent PCAMs. I do not believe that a PCAM has been justified on the basis of the record in this proceeding or that an interim PCAM should now be established. As I discussed in my direct testimony, PacifiCorp has provided scarcely any justification for a PCAM. Mr. Galbraith adds little to that discussion. There is simply no basis to conclude in this Docket that a comprehensive PCAM should be established now, whether temporary or permanent.

<u>Staff Recommendation # 2</u>

> - *The Commission should indicate a preference for a PCAM mechanism with a deadband set: (1) to exclude a reasonable range of normal variation from triggering the PCA mechanism, and (2) to be neutral on an expected recovery basis. For example, a deadband set at the 10th and 90th percentiles of the 'All-in' NVPC distribution, as distinguished from the 'Hydro-only' NVPC distribution, would satisfy these criteria.*
>
> - *The Commission should indicate a preference for updating the PCA deadband annually to account for changing economic relationships. When underlying economic conditions change (for example a change in the hydroelectric generation and electricity*

> *market price relationship) prior NVPC modeling and any associated findings or conclusions become invalid.*

Id. at Galbraith/2-3. I disagree with the implications of these statements, though I agree with some of Mr. Galbraith's sentiments. Again, I am not recommending that the Commission adopt any PCAM at this time. Should the Commission choose to implement some mechanism, an "extreme event" PCAM such as the one proposed by Staff is a more acceptable concept than a PCAM that would be in effect most of the time. However, an "extreme event" hydro-only adjustment clause would be preferable to a comprehensive PCAM (with an "all encompassing" scope of cost recovery) as envisioned by the Staff. A full PCAM has not been justified based on the record in this Docket, would be a much more complex undertaking, requires much more regulatory activity, and would not necessarily achieve Staff's goal of revenue neutrality.

Staff Recommendation # 3

- *The Commission should adopt an interim PCA mechanism for calendar years 2005 and 2006. The deadband should be set at an amount equal to the revenue requirement effect of plus and minus 250 basis points of [Return on Equity ("ROE")].*

Id. at Galbraith/3. I strongly disagree with the Staff proposal to implement an interim PCAM. *If* a PCAM is to be established, then a broad deadband is an element that could help to ensure that PacifiCorp has the proper incentives to manage its power costs. PacifiCorp's recommendation of no deadband is similar to requesting a blank check from customers.

<u>Staff Recommendation # 4</u>

- *The Commission should ensure any PCAM proposal does not incent direct-access eligible customers on their choice to go direct access or remain with the company.*

<u>Id.</u> I agree with this recommendation.

Q. STARTING WITH YOUR FIRST AREA OF DISAGREEMENT, EXPLAIN WHY YOU DO NOT BELIEVE THAT A PCAM HAS BEEN JUSTIFIED BY THE RECORD IN THIS PROCEEDING.

A. The discussion in Mr. Galbraith's testimony seems to be based on the premise that some form of a comprehensive PCAM should be the ultimate outcome of this proceeding. However, Staff adds little or nothing to the minimal discussion of this issue presented by the Company. Further, Staff has not provided a specific PCAM tariff to examine, projections of ratepayer impact, or rules or procedures to govern the annual process of reviewing and determining the ratemaking treatment of any PCAM balance.

Q. DO YOU AGREE WITH STAFF'S RECOMMENDATION FOR AN INTERIM PCAM?

A. No, particularly because it is supported by Staff's recommendation to allow PacifiCorp to use the deferral request in UM 1193 as the basis for the interim PCAM to be implemented, retroactive to February 1, 2005.

This aspect of the Staff proposal broadens the scope of power cost deferral to encompass a wide range of causes that have nothing to do with the request made by the Company to defer costs due to a hydro generation deficit in UM 1193. A serious plant outage, such as PacifiCorp's November 2000 outage of Hunter Unit 1, could result in an automatic pass-through of costs based on the Staff proposal. Another Western energy crisis might result in the same. Indeed, any circumstance that caused power costs to increase would be deferrable, and ultimately recoverable under Staff's interim PCAM proposal.

In the end, the greatest flaw in Staff's proposal is that it is premature. There are a number of issues that should be addressed before a PCAM is adopted. Staff's proposal truncates a fair and reasonable process because it assumes that a retroactive interim PCAM is the "right solution," without providing the justification for a comprehensive PCAM. Furthermore, Staff ignores many practical implementation issues that would accompany a PCAM.

Q. WHAT STEPS ARE NECESSARY BEFORE A COMPREHENSIVE PCAM IS IMPLEMENTED?

A. There should be a multi-step process. *First*, PacifiCorp or Staff must demonstrate to the Commission that a PCAM is necessary and justified, and that a PCAM represents the best means for dealing with power cost variances. This would logically take place in the context of a full general rate case. *Second*, there should be a Commission rulemaking or investigation to define the scope of eligible costs, minimum filing requirements, and time schedules for processing PCAM cases. *Finally*, there should be investigation of provisions for prudence reviews and an audit or reconciliation procedure to assure that non-power cost items are not being included in the PCAM balance.

Q. WHY IS A GENERAL RATE CASE NECESSARY BEFORE DECIDING WHETHER TO IMPLEMENT A PCAM?

A. I discussed this in my direct testimony. Staff also seems to agree that a permanent PCAM needs to be designed in the context of a full general rate case.[1/] However, Staff recommends that a two-year PCAM be implemented now. Staff/100, Galbraith/12-13. Unfortunately, a temporary PCAM presents the same problems and concerns to the Commission as would be present in the case of a permanent PCAM. Further, "temporary" solutions have a way of becoming "permanent" in regulatory situations. Consequently, Staff's position on this point seems inconsistent. It makes little sense to proceed with a temporary PCAM, if the intent is only to replace it with a permanent PCAM later on. If the intent is to simply implement a permanent PCAM, then it is not appropriate to disguise it as a temporary one in this case.

Q. IS STAFF PROPOSING THE TEMPORARY PCAM AS AN EMERGENCY MEASURE TO DEAL WITH THE CURRENT DROUGHT?

A. No. Staff provides very little justification for its temporary PCAM in its testimony. The basic argument is one of developing a "fair allocation" of NVPC risk. Mr. Galbraith testifies as follows:

> Staff recommends the interim PCAM as part of a long-term commitment to the fair allocation of NVPC risk. Staff's interim PCA bridges the gap until a long-term PCA can be implemented. We believe it is important to maintain this long-term focus. Without further examination of the facts underlying Docket UM

1/ "Staff recommends that PacifiCorp use stochastic power cost modeling in its next general rate case. This modeling should be used to jointly determine the NVPC component of PacifiCorp's revenue requirement and the deadband parameters of an extreme event PCA mechanism." Staff/100, Galbraith/12.

> 1193, staff is unsure if the 2005 hydro variance warrants deferred accounting on a one-time stand-alone basis. However, we have already noted the similarity between our interim PCA and the Commission's use of 250 basis points of ROE to benchmark the financial impact of poor hydro in Order 04-108.

Staff/100, Galbraith/23. Of course, "fairness" is a subjective concept. However, I question how "fair" the Staff proposal is to ratepayers since it allows the Company to establish a PCAM and collect costs for which the Company has never even previously requested a deferral. I will discuss this problem in more depth later.

Q. WHY WOULD A RULEMAKING OR A COMMISSION ORDER BE NECESSARY BEFORE IMPLEMENTING A PCAM?

A. There needs to be a reasonable definition of eligible power cost expense. While it may seem simple to define eligible expenses, it is not. For example, in Portland General Electric Company's ("PGE") recent Resource Valuation Mechanism ("RVM") cases, there have been a number of issues that have arisen surrounding the proper scope of costs for inclusion in the RVM. For example, PGE has requested recovery of costs related to foreign currency hedges. Likewise, recovery of costs related to "coal dust" and call options have been included in RVM filings, and opposed at various times by parties, *including* the Staff. In fact, there has been much discussion in the RVM cases as to which costs should be included and which should not.

The RVM is a different exercise than a PCA, and the issues would most certainly differ. However, there is no reason to expect that there would be general agreement regarding the kinds of costs that should be eligible for recovery. While "coal dust" might not be an issue in a PCA case, an unexplained decline in coal inventories might give rise to a request for recovery.[2/]

Likewise, in the recent PacifiCorp power cost audit, out-of-period adjustments were a very contentious issue, even after Staff hired an outside auditor to review PacifiCorp's books. Thus, a rulemaking or a generic proceeding regarding power costs is needed to prevent a PCAM from spawning either a series of unwieldy and open-ended dockets that wrestle with a variety of issues over and over again or the alternative, which would amount to no review of eligible costs and essentially a "blank check" for PacifiCorp.

Further, without minimum filing requirements and reasonable time schedules, parties may be severely handicapped in their ability to audit PacifiCorp's request. Staff provides little guidance on how PCAM cases are to be processed once the PCAM is implemented.

Q. DO YOU AGREE WITH STAFF'S PROPOSAL TO ALLOW ITS PROPOSED PCAM TO RETROACTIVELY APPLY TO 2005?

A. No. Mr. Galbraith testifies that the deferral application the Company filed in UM 1193 is sufficient to allow the Commission to apply Staff's proposed PCAM retroactively to 2005:

> PacifiCorp filed an application for deferral of costs and benefits due to hydro generation variance on February 1, 2005 (Docket UM 1193). PacifiCorp indicated in its initial application that it intended to [to] track increased power costs for later inclusion in rates, either through an amortization schedule or as a part of a PCAM. UM 1193 Application, page 1. The UM 1193 application provides the Commission options with respect to the date at which benefits and costs associated with PacifiCorp's proposed PCA mechanism are eligible for deferral. Staff believes the

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2/ Such a decline might occur whenever coal pile measurements are updated.

> Commission also has the discretion to modify the proposed balancing account formula.

Staff/100, Galbraith/22. I believe that Mr. Galbraith is recommending that the Commission engage in retroactive ratemaking, which is ill advised from a regulatory policy standpoint and may be contrary to Oregon law.

If Staff's proposal is approved, it would certainly create a troubling precedent for regulators, ratepayers, and perhaps even utilities. In effect, Mr. Galbraith suggests that an application for deferral of one type of cost is sufficient to allow deferral of a whole range of loosely defined "related" costs. In UM 1193, the Company requested deferral of replacement power costs resulting from a *shortfall in hydro generation*. The Staff proposal would now retroactively allow the Company to defer *any* component of net power cost variations as well as gas resale revenues based on a deferred accounting application related only to hydro generation variances. If the Commission adopts the Staff proposal, it will "let the genie of retroactive ratemaking out of the bottle of deferred accounting" and greatly complicate the regulatory treatment of deferred costs in future cases. It would also potentially provide PacifiCorp with a far broader range of deferred costs in UM 1193 than it requested. In addition, customers have no notice that the power cost component of their rates may be increased retroactively. There is a major difference in filing a hydro deferred account versus a generic power cost deferred account.

Q. PLEASE EXPLAIN.

A. As noted by Mr. Galbraith, PacifiCorp requested the authorization to defer certain costs related to poor hydro conditions, for possible amortization or inclusion in a

PCAM. Mr. Galbraith proposes to allow a PCAM that not only includes NVPC cost variances due to poor hydro, but *any other cause as well* (i.e., increased fuel prices, increased power prices, load increases, plant outages, etc.) Thus, Mr. Galbraith proposes an interim PCAM that would give the Company more than it even requested in its deferral application in UM 1193.

Q. EXPLAIN THE REGULATORY SIGNIFICANCE OF DEFERRED COSTS.

A. As a general principle, there is a strict prohibition against retroactive ratemaking. <u>See</u> Or. Att'y Gen. Op. No. 6076 (Mar. 18, 1987). The reason is that regulators do not want to have to deal with the problem of constant rate adjustments that would naturally occur because a utility will never exactly earn its allowed rate of return. Once a rate case is decided, regulators, customers, and utilities need finality. If a utility had an unexpected cost (or obtained some sort of windfall), one party or the other might seek an after-the-fact adjustment to eliminate the effects on earnings. This would quickly result in a chaotic situation, making rate setting much more difficult and complicated. Thus, regulators will generally not allow utilities to charge for costs that were incurred between rate cases and outside of any particular test year. To circumvent problems that might accompany unusual circumstances, regulators will sometimes grant an application to defer *certain specific costs* occurring outside of a test year so that a utility may request later recovery without fear of foreclosure on the grounds of retroactive ratemaking.

The problem with the Staff proposal is that it would allow a retroactive modification to the scope of costs being deferred. This could create countless problems in future deferral cases, for both utilities and customers.

Q. ARE THERE OTHER TROUBLING ASPECTS OF THE STAFF INTERIM PCAM PROPOSAL?

A. Yes. The Staff proposal effectively assumes the Commission should grant PacifiCorp's deferral request in UM 1193. However, it is clear that it is very unlikely that PacifiCorp's request in UM 1193 would be approved under the standards established by the Commission in UM 1071 and UM 1147. Re PGE, OPUC Docket No. UM 1071, Order No. 04-108 (Mar. 2, 2004); Re Staff Request to Open an Investigation Related to Deferred Accounting, OPUC Docket No. UM 1147, Order No. 05-1070 (Oct. 5, 2005).

This is a second major flaw with the Staff's interim PCAM. In effect, the Staff would grant (and substantially broaden) the request for deferral in UM 1193. However, in the PGE hydro deferral proceeding, UM 1071, the Commission flatly denied a similar request for deferral of hydro cost variances. For the interim PCAM to provide a reasonable outcome of UM 1193, one must assume that the Commission would grant the deferral request. The precedent in UM 1071 and the standards adopted in UM 1147 suggests that the deferral in UM 1193 should not be granted.

In addition, the UM 1193 deferral request should be independently evaluated and not merged into this very different proceeding. The parties to this proceeding have not had an opportunity to independently review the merits of the UM 1193 hydro deferral, and it would be inappropriate to consider including the hydro deferral in this proceeding without providing the parties an opportunity to submit direct testimony responding to all the issues raised in UM 1193.

UM 1071 was an entirely analogous set of circumstances to UM 1193. In that case, PGE requested permission to defer costs related to hydro variations during 2003. In denying the deferral request, the Commission found that hydro cost variations were a "stochastic risk" and therefore inappropriate costs for purposes of a deferral mechanism:

> We agree with Staff that risks normally included in modeling power costs (stochastic risks) are not appropriate for deferred accounting, as long as those risks are reasonably predictable and quantifiable and have no substantial financial impact on the utility. Here, hydro variability has been included and modeled to set PGE's base rates. The hydro year on which PGE bases its application is, as CUB points out, a 1 in 4.5 year event. This cause is not extraordinary enough to justify deferred accounting.

Re PGE, OPUC Docket No. UM 1071, Order No. 04-108 at 9 (Mar. 2, 2004).

Q. WAS THE COMMISSION'S DECISION IN UM 1071 WELL FOUNDED?

A. Yes. The Order was very well reasoned, providing no basis for assuming that it does not apply to the deferred accounting request at issue in UM 1193. The Commission was correct to recognize that "stochastic risks" are already addressed in setting normalized rates. The recognition of hydro as a stochastic risk is important because the Commission already allows for recognition of variations in hydro generation levels via its normalization of net power costs. In GRID, the Company uses a 50-year average of hydro conditions to develop normalized power costs. For this reason, the likelihood of both good and bad hydro conditions is already reflected in rates, and granting a deferral in a poor hydro year would amount to double recovery.

Q. CAN YOU PROVIDE AN EXAMPLE TO ILLUSTRATE THIS?

A. Exhibit ICNU/201 presents a hypothetical example to explain this problem. In the example, the utility uses a power cost model to compute normalized power costs on the basis of five different hydro generation scenarios.[3/] ICNU/201 shows a hypothetical company that has an average of 700 MW of hydro, and replacement power costs of $50/MWh. It shows that under normalized ratemaking, customers are charged $600 million per year as the average cost of power based on average hydro over a five-year period (simplified from 50 years, which is actually what is used). Over five years, the results would all average out and customers would pay what power actually costs, $3.0 billion. The $3.0 billion figure includes both good and bad hydro years. The normalized cost of $600 million is lower than the cost of power in below-average hydro years, but higher than the cost of power in good hydro years. By using the average value, a "premium" is built into the normalized cost of power in good years that provides a form of "insurance" against bad hydro years.

Assume now that year five is the worst hydro year and the utility requests a deferral to allow it to ultimately recover the additional power costs. If regulators allow the Company to have a deferral in a bad hydro year, the Company gets the benefit of the "premium" built in during the good years, and then effectively charges the actual cost in year five. Under this scenario, ratepayers pay the normalized cost of power ($600 million) for the first four years

3/ PGE actually averages the hydro inputs in Monet in a single run, rather than performing a multiple water year run. However, the use of this approach is not conceptually different from the method shown in the table.

and the actual cost of power in year five. The total cost of power to customers in that scenario is $3.044 billion, resulting in an overcharge to customers of $44 million.

In the example above, the higher-than-normal costs of a bad hydro year ($43.8 million) are averaged into rates every year. However, instead of getting a "free pass" when the bad hydro year actually arrives, customers are now required to pay for bad hydro conditions as well. When above-normal hydro conditions occur, customers pay the normalized cost and the Company keeps the savings. When below-normal hydro conditions occur, the Company changes the rules of the game and asks for recovery of the total cost. So this is a "heads I win, tails you lose" type of hydro normalization that should not be allowed by regulators. The Commission was wise to have recognized this problem in UM 1071. Indeed, in UM 1147, the Commission reinforced the UM 1071 decision with its comment that "[i]f the event was not modeled or foreseen, without extenuating circumstances, the magnitude of harm must be substantial to warrant the Commission's exercise of discretion in opening a deferred account." Order No. 05-1070 at 7. The hydro variations were modeled and foreseen in the GRID modeling studies, so there is no basis for assuming that these standards do not apply in UM 1193. The Commission should not abandon its reasoning in UM 1071 and UM 1147 in this case.

Q. IT MIGHT BE SUGGESTED THAT INSTITUTION OF AN INTERIM PCAM WOULD MITIGATE THE PROBLEM OF UNEQUAL TREATMENT IN GOOD AND BAD HYDRO YEARS BY DEVELOPING A PREDETERMINED TREATMENT OF HYDRO COST VARIATIONS. DO YOU AGREE?

A. No. *First*, this regulatory change is being suggested in a year in which the utility already expects poor hydro conditions to prevail. Thus, it virtually assures the utility of a positive recovery balance in year one.

Second, the interim PCAM is only a temporary mechanism. After two years it may be replaced by some other (as yet unknown) mechanism or there may be no mechanism at all. There is nothing to require PacifiCorp to seek a PCAM in the future should circumstances suddenly appear more favorable to it without one. For the interim PCAM to be a fair solution, it would have to be in effect long enough so that ratepayer benefits in good hydro years would balance out with the expected high cost in the first year. The interim PCAM, however, would only be in effect through 2006. Recall that Mr. Galbraith testified that revenue neutrality was a desirable goal for a PCAM. Staff/100, Galbraith/13. Allowing implementation of the interim PCAM after it is known to produce a positive cost variance in the very first year is inequitable. This, of course, is yet one more reason why it should not be implemented retroactive to February 1, 2005.

Q. DOES THE STAFF PROPOSAL DEPART FROM THE PRECEDENT SET IN UM 1071 IN OTHER WAYS?

A. Yes. In UM 1071, the Commission also determined that an event that represents a stochastic risk must have a "substantial" financial impact on the utility:

> The magnitude of the financial effect on the utility is also a factor in our consideration under the discretionary stage of the decision process. For a stochastic risk to justify deferred accounting, the

> financial impact must be substantial. Although we decline to set a numerical criterion, we can give negative and positive examples. In UM 995, for instance, we established a deadband around PacifiCorp's baseline of 250 basis points of return on equity. We allowed no recovery of costs or refunds to customers within that deadband, reasoning that the band represented risks assumed, or rewards gained, in the course of the utility business. In the Idaho Power cases, discussed below, we allowed partial recovery for a financial impact that represented approximately 700 basis points of Idaho Power's return on equity.
>
> * * *
>
> In the present application, PGE claims that it has incurred $31.6 million in excess NVPC, only some of which is attributable to hydro replacement costs. PGE asserts that this excess NVPC amounts to 172 basis points of return on equity. This is well short of the 250 basis points of return on equity within which we allowed no recovery in UM 995.

Order No. 04-108 at 9 (internal citations omitted). As discussed above, this principle was reinforced in UM 1147.

While the Commission did not articulate a hard and fast standard regarding the appropriate deadband, the Commission considered an impact within a 250 basis point deadband inadequate in UM 995, and it found that PGE's projected hydro variance of $31.6 million was inadequate in UM 1071. For PGE that equates to approximately 200 basis points.

Q. HOW DO THESE STANDARDS RELATE TO THE INSTANT CASES?

A. Based on PacifiCorp's UM 1193 testimony, the Company estimated the cost of the hydro deficit to be $86 million on a total Company basis. Re PacifiCorp, OPUC Docket No. UM 1193, PPL/103, Widmer/1. For PacifiCorp this amounts to less than 150 basis points. See Re PacifiCorp, OPUC Docket No. UE 170, PPL/801, Weston/2.2 (Nov. 12, 2004) (showing that 100 basis points equals $60 million). I will show later that even this estimate was greatly overstated. Obviously this falls well short of the 250 basis point deadband adopted in UM 995, and is even less than the ROE impact considered inadequate by the Commission in UM 1071. This implies strongly that the Commission should deny the request for deferral in UM 1193.

Q. DO YOU HAVE ANY CONCERNS REGARDING STAFF'S 250 BASIS POINT DEADBAND PROPOSAL?

A. Yes. I have three concerns. *First*, based on the above-referenced PacifiCorp "Results of Operations," 100 basis points equates to $60 million per year. Thus, 250 basis points would equal $150 million per year. Id. Future reliance on a 250 basis point deadband is complicated because it requires financial data to calculate. This could either entail use of un-audited financial results, projected financial results, or data from the most recent rate case. Staff has not explained specifically how it would determine the deadband.

Second, and more significantly, Staff has indicated that symmetrical sharing bands for the PCAM could lead to a windfall for PacifiCorp. Staff/100, Galbraith/10. However, Staff still proposes symmetrical sharing bands and a symmetrical deadband for the interim 2005 and 2006 PCA. Id. at Galbraith/21.

Finally, there is the practical issue of timing accompanying the Staff deadband. It would be necessary to decide whether the deadband applies monthly, quarterly, or annually. This has not been addressed by Staff. A monthly deadband might allow the Company to make a positive deferral, because certain months had cost variations in excess of 250 basis points (annualized), even though the annual variations did not exceed that deadband. Again, issues of this sort need to be addressed in a rulemaking or investigation.

Q. IF STAFF'S PROPOSED DEADBAND IS ADOPTED, DOES THIS MINIMIZE THE LIKELIHOOD THAT ADDITIONAL AUDITS WOULD BE NEEDED?

A. Certainly a broad deadband would imply that there would be fewer times when the Company might obtain rate treatment for additional power costs. However, I believe that some form of audit needs to be undertaken every year to establish whether the actual power costs fall within the deadband or not. If the Commission makes a decision regarding whether NVPC falls within the deadband, it is implicitly accepting the components of NVPC as filed by the Company. Utilities are quite adept at claiming precedents in cases where costs have been "approved" in rate cases, or at least not disallowed, when no challenge was raised. It is not hard to imagine a set of circumstances where the lack of a challenge to costs, revenues, or an accounting method included in PacifiCorp's calculation of NVPC for a given year (when the deadband was not exceeded) gives rise to a claim that a precedent had therefore been established. Thus, a comprehensive audit may be needed on an on-going basis.

Further, if PacifiCorp were in a situation where NVPC was below the level included in rates, it would naturally have an incentive to overstate its costs, to avoid a refund. In such a case, an audit would be needed to verify the Company's claimed NVPC.

Q. IN UM 1193, THE COMPANY REQUESTED A DEFERRAL OF HYDRO COSTS. DOES THIS REQUEST PLACE A LIMIT ON HOW MUCH MONEY THE COMPANY MAY BE ALLOWED TO DEFER UNDER THE STAFF PCAM PROPOSAL?

A. Yes. The Company should not be allowed to defer any more money under the Staff PCAM proposal than would have been the case had UM 1193 been litigated with an award made to the Company. As a result, I believe that if the Commission decided to implement the Staff interim PCAM, it must also decide what the proper deferral would have been in UM 1193. This would provide the maximum amount that would be allowable in the Staff interim PCAM. Consequently, I present a corrected calculation to illustrate the proper deferral level for that case in Exhibit ICNU/202. In this exhibit, I present a correction to Exhibit PPL/103 from UM 1193. However, I continue to believe these issues related to UM 1193 have not been appropriately included in this proceeding and the Commission should not address the merits of the hydro deferral until the parties have an opportunity to investigate and submit testimony on all issues related to the hydro deferral.

Q. PLEASE EXPLAIN THIS EXHIBIT.

A. In ICNU/202, I correct several problems in the original PPL/103 exhibit. *First*, I correct the "hydro energy in rates" amounts. In PPL/103 from UM 1193, the Company used UE 147 hydro generation levels for all of 2005. However, once the new rates from UE 170 go into effect, the amount of hydro energy included in rates will be reduced, because PacifiCorp had lower hydro generation in its forecast in UE 170 than in UE 147. This reduces the amount of deferred costs.

Second, I used the most recent actual hydro data for April to June 2005 in place of the estimated data used by the Company and used the most recent forecast data. PacifiCorp's response to ICNU data request No. 2.3 in this proceeding provided the most recent data. This also reduced the deferral amounts.

Third, the corrected deferral calculation must properly reflect the jurisdictional allocation method used in setting rates. The Company assumed (incorrectly) that the Revised Protocol was the proper cost allocation method for all of 2005. However, the Company filed UE 147 based on the Modified Accord method. The Revised Protocol is not the proper method for allocation until the time that the new rates from UE 170 go into effect.[4/] As a result, the jurisdictional allocations need to be revised to reflect the actual methodology used to set rates before and after the rates from UE 170 went into effect on October 4, 2005.

Fourth, as I pointed out in my direct testimony, it is incorrect for the Company to apply the DPG and MC allocation factors for the deferral mechanism after the rates from UE 170 are in effect. Instead, the SG and SE factors would apply. It appears that both Staff and the Citizens' Utility Board agree with this position based on their direct testimony. This adjustment also reduces the deferral amounts.

As a result of these corrections, the maximum amount of costs deferrable by the Company for 2005 should be approximately $5.6 million (based on current

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4/ It is a bit ironic that PacifiCorp used the higher hydro figures from UE 147 for all of 2005, but used the more costly allocation methodology, the Revised Protocol, from UE 170 for all of 2005.

hydro forecasts). This amount is much lower than the Oregon deferral of $51.2 million projected by the Company in PPL/103 from UM 1193.

Q. DO YOU HAVE ANY OTHER CONCERNS REGARDING THE STAFF INTERIM PCAM PROPOSAL?

A. Yes. Any form of PCAM can provide perverse incentives for the utility to "manage" its accounting rather than managing its costs. By this I mean that the Company has the incentive to book costs to inappropriate accounts, and evaluate transactions based on their cost recovery status, rather than to select transactions to minimize costs.

Q. PLEASE ELABORATE.

A. These observations are nothing new. In fact, they have already been made by PacifiCorp in the past when it requested elimination of the Utah Energy Balancing Account ("EBA"), a mechanism similar to a PCAM. Re Utah Power & Light, Utah Public Service Commission Docket No. 90-035-06. In his May 1990 testimony before the Utah Commission, PacifiCorp witness Verl R. Topham testified that elimination of the then existing PCA was necessary for several reasons.[5/] ICNU/203. Mr. Topham argued that the EBA impeded the ability of management to respond appropriately to competition and to "manage the Company." Id. at 5:5-22. Mr. Topham further argued that an EBA had the unintended tendency to benefit or penalize customers as actual retail loads fluctuated from test period loads. He also stated that it raised questions about retroactive ratemaking. Id. at 5:23 – 6:2.

5/ Mr. Topham used the terms EBA and PCA more or less interchangeably in his testimony.

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) such as extreme volatility of fuel costs are not currently applicable to the Company." Id. at 4:18-21. While Mr. Topham suggested that volatility of purchased power costs could be another reason for supporting a PCA, the Company's net power costs need not be impacted by wholesale price movements, because net purchases (total purchases minus sales) are a very small percentage of total resources.

Q. PLEASE SUMMARIZE THESE POINTS.

A. The problems with a PCAM type mechanism are well known, and widely recognized. Even the Company has admitted to these issues in the past. Staff's proposal to implement an interim PCAM, followed by a permanent PCAM after 2006, would be a poor policy choice for the Commission, and should be rejected.

2. IMPLICATIONS OF THE UE 170 ORDER

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

A. Parties to this case have been afforded the opportunity to comment on the implications of the UE 170 Order in relation to PacifiCorp's request for a PCAM.

Q. WHAT ASPECTS OF THE UE 170 ORDER WILL YOU ADDRESS?

A. I will address the implication of the Commission's approval of the PacifiCorp TAM with annual update as it applies to the PCAM. I will also discuss the implications of the Commission's adoption of the various partial stipulations and how that might effect implementation of the PCAM.

Q. THE COMMISSION APPROVED THE PACIFICORP TAM (WITH AN ANNUAL UPDATE) IN ORDER NO. 05-1050. COMMENT ON HOW THIS IMPACTS THE NEED FOR THE PCAM.

A. As concerns the annual update of power costs, PacifiCorp's TAM will be quite comparable to PGE's RVM. As a result, the TAM accomplishes many things that the PCAM would accomplish. It will greatly reduce regulatory lag for power costs and will insure that estimates of new power costs built into rates are quite up to date. Indeed, some of the most critical cost inputs (purchase power and gas contracts) will be updated as late as November of each year. Thus, the TAM may be thought of as a forward-looking PCAM. In fact, Ms. Omohundro counts PGE as one of the seven regional utilities with a PCAM (<u>See</u> PPL/102, Omohundro/3) even though up until now and for the past several years, that company has only had an RVM.

Q. IS THERE ANY DISPUTE THAT THE TAM AND PCAM ACCOMPLISH THE SAME FUNCTION OF THE VARIATION BETWEEN ACTUAL NET POWER COSTS AND THOSE REFLECTED IN RATES?

A. No. In fact, in its current Washington rate case, the Company admitted as much in its testimony supporting its PCAM request. In that case, Mr. Widmer testified that Oregon needed a lower sharing percentage (70% vs. 90%) than Washington because the Company had proposed (and apparently assumed it would be awarded) the TAM in Oregon. ICNU/204. Because the Company proposed no TAM in Washington, he suggested that a higher sharing percentage was needed. <u>Id.</u> While I don't agree that the Company needs the TAM or PCAM in either state, the Company clearly believes that the TAM reduces its power cost risks to a significant degree.

Q. DID THE COMMISSION EXPRESS ANY CONCERNS ABOUT ITS ADOPTION OF THE RVM IN THE UE 170 ORDER?

A. Yes. The Commission indicated it was concerned with the possible "one-sidedness" to PacifiCorp's annual updates. Re PacifiCorp, OPUC Docket No. UE 170, Order No. 05-1050 at 21 (Sept. 28, 2005). Certainly, this underscores the need to move forward with some caution with respect to the implementation of yet another major regulatory change at this time. The Commission is already concerned with the impact of the TAM and its possible one-sidedness. It should not now also adopt a new and untested PCAM, at virtually the same time.

Q. WHAT ARE SOME OF THE CONCERNS THAT ARISE WHEN BOTH A PCAM AND TAM ARE IN PLACE AT THE SAME TIME?

A. *First*, there is the intensification of regulatory activity for Staff and intervenors, especially because both PGE and PacifiCorp will be processing their annual power cost updates at virtually the same time.

Second, there is the complexity of dealing with the same issues in two proceedings. As I discussed in my direct testimony, great clarity will be required in processing Commission orders for TAM and PCAM issues. Costs disallowed in the TAM proceedings must be carefully tracked in the PCAM cases, or else they may be indirectly allowed into rates. For example, in UE 170 a hydro hedge was originally included in power costs by the Company. While the First Partial Stipulation resolved the issue, it did not specify whether the hedge was disallowed or not. Thus, treatment of that issue in the PCAM would be unclear. Assuming the Commission were to disallow such costs later in the TAM, it must also disallow them in the PCAM. While that might be simple in the case of a hydro hedge, it could be quite complex in a case where a specific contract was disallowed. In such a case, it is a simple matter to run GRID without the contract in the TAM. However, adjusting actual costs to remove such a contract in the PCAM is another matter. Because actual loads, hydro conditions, and market prices will differ from TAM GRID assumptions, it will not be possible to simply apply the model results to actual costs.

Third, recent cases with PacifiCorp (including UE 170) have featured full or partial settlements of power cost issues. In situations where a single "black box" disallowance has been applied to power cost issues in the setting of base rates, it will be quite ambiguous as to what adjustments should be made to actual. In my view, the only practical solution will be to view PCAM cases, as being largely independent of prior TAM case, especially after cases with ambiguous settlements. This will either make parties less likely to enter into settlements, or complicate the PCAM with litigation over some of the same issues as arose in the TAM cases.

Further, some issues exist in development of actual costs that never arise in models like GRID. Out-of-period adjustments, for example, are not a problem in GRID, but can be a substantial issue when computing actual costs.

All in all, adoption of the TAM is going to substantially increase the regulatory burden on Staff and intervenors, as well as the Commission. Because the PCAM accomplishes many of the same things as the TAM, I suggest the Commission call a moratorium on such ratemaking concepts until at least

PacifiCorp's next general rate case, after some practical regulatory experience has been gained with the implementation of the TAM.

Q. ORDER 05-1070 IN UM 1147 PROVIDES SOME COMMENTS ENCOURAGING PARTIES TO EXPLORE A PROPERLY STRUCTURED PCA. PLEASE COMMENT.

A. Certainly that order indicates the Commission is interested in further exploration of the PCAM concept. As the order states, however, the PCAM must be properly structured. In my direct testimony, I have already indicated the reasons why PacifiCorp's proposal is not properly structured. Further, the TAM is already a substitute for a PCAM. Given the Commission's adoption of the TAM in UE 170, I suggest that the goals stated by the Commission in UM 1147 have already been satisfied.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

ICNU/201

Example of Overcollection Problem

Exhibit ICNU/201
Example of Overcollection Problem

Year	Hydro Avg. mW	NPC M$	Normalized Ratepayer Cost	Ratepayer Cost Cost with Deferal Y 5
1	800	556.2	600.0	600.0
2	750	578.1	600.0	600.0
3	700	600.0	600.0	600.0
4	650	621.9	600.0	600.0
5	600	643.8	600.0	643.8
Avg.	700	600.0	600.0	
Total Ratepayer Cost		3000	3000.0	3043.8
			Overcollection	43.8

ICNU/202

Corrected Calculation of Possible Deferral

Exhibit ICNU/202
Corrected Calculation of Possible Deferral (PPL/103)

				Actual Feb-05	Mar-05	Apr-05	May-05	Jun-05	Forecast Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
Hydro Generation - Deferral Period														
	West Hydro		2,786,617	211,436	199,756	309,970	361,612	213,355	161,686	163,574	138,170	227,688	356,102	443,269
	East Hydro		350,427	12,664	28,033	48,656	63,261	51,025	30,783	28,116	18,196	20,567	21,598	27,527
	Mid C		1,630,997	165,307	162,993	133,131	160,569	164,573	171,246	164,091	110,429	116,345	133,770	148,543
Total Hydro Generation			4,768,041	389,407	390,782	491,757	585,442	428,953	363,715	355,781	266,794	364,600	511,470	619,339
Hydro Generation - In Rates														
	West Hydro		3,469,320	498,123	452,856	340,184	290,451	274,161	236,127	200,543	217,768	211,764	300,639	446,705
	East Hydro		495,169	32,652	45,171	49,050	57,668	51,976	51,678	47,960	37,444	39,156	40,046	42,368
	Mid C		1,642,191	195,609	158,364	117,822	156,339	169,046	172,589	148,339	134,955	108,910	135,024	145,194
Total Hydro Generation			5,606,680	726,384	656,391	507,056	504,458	495,182	460,395	396,841	390,168	359,830	475,708	634,267
	Mid C	80%		45.87	48.26	50.59	55.87	61.07	71.38	74.75	68.53	62.87	65.34	70.27
	Jim Bridger	10%		13.19	12.52	12.40	12.40	12.40	12.40	12.40	12.40	12.40	12.40	12.40
	Hermiston	10%		26.81	26.78	27.48	27.48	27.48	27.48	27.48	27.48	27.48	27.48	27.48
	Weighted Cost		0.00	40.70	42.54	44.46	48.68	52.84	61.09	63.79	58.81	54.28	56.26	60.20
Change In Hydro	**West Hydro**			286,687	253,100	30,214	(71,161)	60,806	74,441	36,969	79,599	(15,924)	(55,463)	3,437
	East Hydro			19,988	17,138	394	(5,593)	951	20,895	19,844	19,248	18,589	18,448	14,841
	Mid C			30,302	(4,629)	(15,309)	(4,230)	4,473	1,343	(15,752)	24,527	(7,435)	1,253	(3,349)
	Total		838,639	336,977	265,609	15,299	(80,984)	66,229	96,680	41,060	123,373	(4,770)	(35,762)	14,928
Cost - Total Company Basis														
	West Hydro		31,334,867	11,666,995	10,766,386	1,343,295	(3,464,396)	3,213,209	4,547,745	2,358,155	4,681,356	(864,405)	(3,120,366)	206,893
	East Hydro		-	813,439	728,999	17,532	(272,279)	50,238	1,276,545	1,265,780	1,132,023	1,009,073	1,037,885	893,469
	Mid C		371,062	1,233,183	(196,921)	(680,641)	(205,957)	236,367	82,060	(1,004,785)	1,442,461	(403,579)	70,504	(201,630)
	Total		39,658,632	13,713,617	11,298,464	680,186	(3,942,631)	3,499,813	5,906,350	2,619,149	7,255,841	(258,912)	(2,011,977)	898,732
PacifiCorp Calculation of Allocation to Oregon														
Oregon Allocated Amounts	**MSP Factor**													
West Hydro	**DGP**	**55.6575%**	17,440,204	$6,493,558	$5,992,301	$747,645	-$1,928,196	$1,788,392	$2,531,161	$1,312,490	$2,605,526	-$481,106	-$1,736,718	$115,152
East Hydro	**SG**	**28.5551%**	2,270,902	$232,278	$208,166	$5,006	-$77,749	$14,345	$364,519	$361,445	$323,250	$288,142	$296,369	$255,131
Mid C	**MC**	**65.8902%**	244,493	$812,547	-$129,752	-$448,476	-$135,705	$155,742	$54,070	-$662,055	$950,441	-$265,919	$46,455	-$132,855
		Total Compa	19,955,599	$7,538,383	$6,070,716	$304,175	-$2,141,651	$1,958,479	$2,949,750	$1,011,880	$3,879,217	-$458,884	-$1,393,893	$237,428
		Oregon Share												
		System Allocation Factor		28.141%	28.141%	28.141%	28.141%	28.141%	28.141%	28.141%	28.141%	28.5551%	28.5551%	28.5551%
		System Cost	5,609,120	$2,121,413	$1,708,389	$85,599	-$602,692	$551,145	$830,103	$284,758	$1,091,669	-$131,035	-$398,028	$67,798

ICNU/203

Prefiled Direct Testimony of
Verl R. Topham in
Utah Public Service Commission
Docket No. 90-035-06

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE INVESTIGATION) OF THE REASONABLENESS OF ALLOCATION) AND THE RATES AND CHARGES FOR UTAH) POWER & LIGHT COMPANY)	Docket No. 90-035-06 PREFILED DIRECT TESTIMONY OF VERL R. TOPHAM

May 1990

Q. Please state your name, business address, and present position with PacifiCorp.

A. My name is Verl R. Topham. My business address is 1407 West North Temple St., Salt Lake City, Utah. I am President of Utah Power & Light, a division of PacifiCorp (Company). I also serve as Executive Vice President of PacifiCorp Electric Operations Group.

Q. Please outline your employment history with Utah Power & Light Company.

A. I was elected to my present position with the Company in February, 1990. I have served as Executive Vice President of PacifiCorp Electric Operations since May 1989. I also previously served as Executive Vice President of Utah Power & Light from January, 1989 to February, 1990. Previously, at Utah Power & Light Company, I was elected Vice President and Chief Financial Officer in 1981 and, in 1985, was elected Senior Vice President, Chief Financial Officer and Commercial Manager. Prior to being elected Vice President and Chief Financial Officer, I served as assistant corporate secretary and associate general counsel. Also, since 1984 I have been a member of the Board of Directors of Utah Power & Light Company.

Q. What is your educational background?

A. In 1955, I received a Bachelor of Science Degree in Law from the University of Utah. In 1960, I received a Juris Doctorate Degree in Law from the same institution.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I have testified before the Public Service Commission of Utah (Commission), the Idaho Public Utility Commission, the Wyoming Public Service Commission, and the Federal Energy Regulatory Commission.

Q. Please indicate who the Company witnesses will be in this proceeding and what issues they will address.

A. In his prefiled testimony Mr. Colby will introduce the technical witnesses for the allocation issues. Mr. Gregory N. Duvall will address how net power costs would be calculated for use in determining the Company's revenue requirement if the Commission were to eliminate the Energy Balancing Account (EBA). Mr. Robert R. Dalley will sponsor an Exhibit reflecting results of operations without the EBA [UP&L Exhibit No. 3.4 (RRD-4)]. I will present the policy position of the Company requesting the elimination of the Energy Balancing Account.

Q. How is your testimony organized?

A. I will address the issue of why the EBA should be eliminated as follows:

- The EBA is not appropriate in the Company's current operating environment.
- The EBA impedes management's ability to respond to competition.
- The EBA impedes management's ability to manage the Company.
- Other reasons for elimination of the EBA.
- Proposal for termination of the EBA.

SUMMARY

Q. Mr. Topham, please briefly summarize your testimony.

A. The Company believes that the elimination of the EBA is necessary for several reasons. First, the EBA is not appropriate in the current operating environment of the merged Company. Conditions which may require a power cost adjustment (PCA) clause such as extreme volatility of fuel costs are not currently applicable to the Company. The EBA was established to address the problems of an operating environment which do not exist in the current environment. Regulatory oversight of power costs is not diminished without the EBA. It is also of interest to note that regulatory

Commissions in Arizona, Oregon, Washington, and Montana have recently terminated or denied PCA's for electric utilities subject to their jurisdiction.

Second, the EBA impedes the ability of management to respond appropriately to competition. The Company response to competition is overall stable prices. The EBA makes this policy impossible to implement because it creates price instability.

Third, the EBA impedes management's ability to manage the Company. The EBA impact of potential transactions may render an otherwise beneficial transaction unacceptable. The EBA requires full pass-through of Utah jurisdictional fuel-related net power costs. This impedes the ability of the Company to maintain stable prices by offsetting unavoidable increases in power costs with decreases or cost deferrals in non-power cost areas. The elimination of the EBA provides maximum incentive for management while providing a guaranteed level of performance for customers.

Other reasons for elimination of the EBA include, the unintended phenomenon that benefits or penalizes customers as actual retail loads fluctuate from test period loads. Additionally, the EBA raises questions about retroactive rate making.

The Company therefore proposes to set prices in the second phase of this case without the impact of the EBA. The Company proposes to terminate the EBA collection rate when prices determined in Phase II of this proceeding become effective by transferring Schedule 35 to general rate schedules. The Company proposes that if a payable balance in the EBA exists on that date, it would be returned to customers in a single lump sum distribution. Alternatively, the Company proposes that if a receivable balance exists on that date it would be held as a regulatory asset, to be dealt with in an appropriate future proceeding before this Commission.

THE EBA IS NOT APPROPRIATE TO THE COMPANY'S CURRENT OPERATING ENVIRONMENT

Q. Mr. Topham, under what conditions may a PCA be appropriate?

A. The decision to establish a PCA is a complex issue specific to a particular company. However, I believe the overriding circumstance under which such a mechanism may be appropriate is extreme volatility of power costs over a short period of time.

Q. Do you believe that the current conditions warrant a PCA for the Company?

A. No. I believe that a PCA is not appropriate to the current operating environment of the Company.

Q. Please explain.

A. In the late 1970's and early 1980's certain economic conditions prevailed which severely impacted power markets. For example, the oil embargo coupled with relatively heavy reliance on oil fired generation, as well as double digit inflation significantly impacted power costs. These conditions made forecasting fuel-related net power costs difficult for rate making purposes and contributed toward the Commission decision to establish the EBA in 1979 (See Order in case No.78-035-21, 79-035-03, pp 14 - 17, dated July 20, 1979). By contrast recent years have reflected moderate inflation, and oil prices have generally stabilized. It is therefore not surprising that this stabilized economic environment has resulted in less volatile power costs. The conditions that created the extreme volatility of power costs do not exist in the current economic environment. Therefore, the EBA is not appropriate under such economic conditions.

Q. Are you saying that power cost volatility has been eliminated in the current operating environment?

A. No. Certain power costs, by their nature are subject to weather and water conditions and other factors that are outside the control of management. Therefore they will always reflect a certain degree of volatility. However, the extreme volatility of power costs which previously prevailed has stabilized. This stability has resulted from changed economic conditions and through aggressive management of Company costs.

Q. Will regulatory oversight of power costs be diminished in the absence of the EBA?

A. No. In the absence of the EBA regulatory oversight of power costs will be accomplished principally through the Semi-Annual Results of Operations reports. These reports are intended to provide a detailed basis for the monitoring of Results of Operations between general rate cases. I anticipate that regulators will focus their attention on these reports as a mechanism to monitor overall Company performance. The regulatory oversight of power costs or any other component of results of operations should not be diminished in the least by the elimination of the EBA.

Q. What is the recent experience of other western regulatory agencies relative to PCA's?

A. For the information of the Commission, I believe it is worthy of note that electric utilities in Arizona, Montana, Oregon, and Washington have recently been denied or ordered to terminate PCA's. Additionally, no electric utility in Wyoming, Montana, Oregon, or Washington currently operates under the terms of a PCA mechanism.

Q. Prior to the merger with Utah Power, what was the experience of PacifiCorp regarding the treatment of power costs in the rate making process?

A. Pacific Power & Light jurisdictions, both prior and subsequent to the merger establish normalized power costs for rate making purposes by use of the production cost model. This model has been used for this purpose for over a decade without substantial controversy. Mr. Gregory Duvall explains the production cost model and related theory in his prefiled testimony. Additionally, it should be noted that while other utilities in jurisdictions served by Pacific Power operated under PCA mechanisms, either voluntarily or otherwise, no such mechanism was ever requested by or imposed on Pacific.

Q. Do you have other grounds on which to base your believe that the EBA is not appropriate in the current operating environment of the Company?

A. I think it is important to keep in mind that the power supply system for which the EBA was established in 1979 no longer exists. The nature of the merged Company and its operating environment are not similar to the all thermal-based system of 1979. It therefore seems inappropriate to continue to regulate and operate the Company based on a mechanism that was designed to address issues existing in 1979. I believe that if the Company was not presently operating under the terms of the EBA, the current conditions and operating environment would not require that such a clause be imposed on the Company.

THE EBA IMPEDES MANAGEMENT'S ABILITY TO RESPOND TO COMPETITION

Q. Mr. Topham, please explain the impact of competition on the Company.

A. the Company operates in an environment of ever-increasing competition from independent power producers, public power organizations, self-generators, other investor-owned utilities, as well as alternative energy sources such as natural gas, solar energy and emerging technologies. Many electric customers have more energy options today than ever before. To the extent that customers, particularly large customers, choose an alternative to Company-supplied electric energy, the Company and remaining customers are negatively impacted. Therefore, it is imperative that the Company be able to respond to competitive forces in a proactive and positive manner.

Q. What is the Company's response to competition?

A. The Company response to competition is a commitment to stable prices. Price stability implies no rapid price swings in either direction. The Company believes that price is a major factor in competitive markets, and has been pursuing strategies to maintain and/or reduce its prices for several years. These efforts demonstrate Utah Power's continuing intention to compete successfully. At the same time, the Company believes that its policy of overall price stability is in the best interest of our customers and shareholders. It will help us compete more effectively with other energy suppliers, and will provide customers some predictability about the price they will pay for electric service. It will also allow customers to effectively and efficiently make energy investment decisions for both the acquisition of equipment and the use of energy. We clearly understand that we must provide customers good service at competitive and stable prices if we are to continue to be their energy services company. Price instability simply cannot be tolerated if the Company is to remain competitive in the current operating environment. Often predictability may be as important to a customer as the absolute price, at least within a reasonable band.

Q. How does the EBA limit the ability of the Company to compete?

A. Price adjustments, when they occur should be tied to a deliberate pricing policy aimed at efficient resource use and response to given market conditions. The EBA is a regulatory mechanism which, by the nature of its operation, creates price instability divorced from pricing policy decisions. The EBA, as any balancing account, creates price fluctuations every time the associated surcharge (Schedule 35) is adjusted. This instability is contrary to the Company commitment to overall price stability and thereby inhibits the Company's ability to respond to competition.

Q. Since March, 1988, changes to the EBA collection rate have resulted in substantial price reductions. Are these price reductions consistent with the Company's response to competition?

A. The Company welcomes any opportunity to appropriately reduce customer prices. However, price reductions as a result of EBA collection rate changes are not consistent with the Company's response to competition.

Q. Please explain.

A. EBA collection rate changes are essentially outside the control of the Company. For example, if the balance in the EBA reflects an amount payable to customers, a collection rate must be implemented at a value less than anticipated fuel-related net power cost so that the balance payable can be eliminated. The reversal of that collection rate reduction when the payable balance is eliminated represents an effective price increase to customers. This price shifting is a confusing and inappropriate price signal to customers, and makes it difficult for the Company's management to manage its prices in light of our commitment to overall price stability. Additionally, the price shifts ignore efforts to correct pricing problems between classes of service and runs counter to efficient pricing policy. Therefore, EBA collection rate changes are not consistent with the Company's response to competition.

Q. How does the Company's commitment to overall price stability relate to commitments made by the Company relative to the merger of Utah Power and PacifiCorp.

A. The Company has committed to honor promises of price reductions made in conjunction with the merger. Beyond that, our commitment to stable overall prices does not and cannot reflect a specific promise. Rather, it reflects management's recognition that competitive forces require a proactive and positive response. The Company's response to competition is a commitment to maintain customer prices as stable as economic, environmental, or other conditions outside of management's control will allow.

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. The Company believes in placing the risk of management practices on those that make the business decisions - management - not customers.

Additionally, the best long-term response to the threat of competition is competitive and stable prices. The EBA prevents the Company from fully implementing this strategy in the Utah jurisdiction. We simply believe that the risks to the shareholders and customers of an ineffective response to competition poses a far greater threat than the risk of fluctuating power costs.

<u>EBA IMPEDES MANAGEMENT'S ABILITY TO MANAGE THE COMPANY</u>

Q. Mr. Topham, how does the EBA impact the management of the Company?

A. Due in part to competition, the electric business is more dynamic today than ever before. As new or innovative types of transactions are proposed, their impact on the EBA must be considered. Additionally, any new or modified venture must always be viewed in terms of the related EBA treatment. If the EBA continues in its present form, future transactions will likely be evaluated based, at least in part, on their impact on the EBA.

Q. What is the harm in evaluating the EBA impact of potential transactions?

A. The harm is that the result of such evaluation may require the Company to reject an opportunity, otherwise beneficial to customers and shareholders, simply because of the related EBA impact. The economics of a proposed transaction should stand on their own. Decisions concerning proposed transactions should be based on economics alone, independent of the impact of the EBA.

Q. Do you have an example of such a transaction?

A. I will propose for you this scenario. The Company may be in a position to consummate an arrangement on acquiring an interest in generation facilities. Such a transaction could provide long-term benefits to customers and shareholders. In the absence of the EBA, the Company could make off system sales from the generation of this facility, and use the margin from those sales to support the Company's investment until such time as the facility was included in rate base. However, the EBA passes the Utah jurisdictional portion of secondary sales margin entirely and immediately to Utah customers through the EBA. The Company may therefore be left with limited means to offset the cost of its investment until it is included in rate base. Therefore, a transaction which makes sense economically, and which would provide long-term benefits to the Company's Utah jurisdictional customers, may be declined because of EBA considerations.

Q. Does the EBA impact Company management in other ways?

A. Yes. Tracking of any single cost item in a balancing account reduces management's ability to manage its overall business to achieve the goal of stable prices. Under the Company's proposal, in the absence of the EBA, management would have the flexibility to defer or reduce costs in one area (labor or maintenance for example), in order to offset unavoidable increases in another area (power costs for example). The Company, thereby, has the ability to hold prices stable even in periods of increasing power costs. Under current regulatory practices the EBA would require increased power costs to be reflected in prices through EBA collection rate increases. To accomplish its objective of stable prices the Company would be required to match each EBA price increase with an offsetting general price decrease. Such a scenario impedes the ability of the management to manage its business, and may further complicate the regulatory process.

Q. In the absence of the EBA, what are the implications on the incentive for management efficiency?

A. With or without the EBA, management remains committed to efficient operations. This commitment is demonstrated in part by efficiencies implemented at the Utah Power & Light coal mines which have caused coal costs to drop significantly since 1985. However, I believe that by elimination of the EBA, management is afforded maximum incentive for efficiency because the Company could be rewarded with some of the benefits of power cost efficiencies between general rate cases.

Q. In the absence of the EBA, how will customers benefit from power cost efficiencies?

A. Customers will benefit through overall stable prices. Such prices will send proper and consistent pricing signals to customers and at the same time allow customers to make energy investment decisions based on predictable prices which will not fluctuate with the operation of the EBA. Prices will be based on power costs which guarantee retail customers a certain level of power cost efficiencies whether those efficiencies are achieved or not.

<u>OTHER REASONS FOR ELIMINATION OF THE EBA</u>

Q. Does the EBA impact the Company when actual retail loads fluctuate from test period loads upon which prices were set?

A. Yes. The impact is based on the premise that the Company's energy resources are fixed, and that as retail loads fluctuate from test period loads, more or less of the Company's energy resources are available to make secondary sales.

Q. What is the impact on the Company when test period retail loads exceed actual loads?

A. The first impact is the obvious penalty of retail revenue loss resulting from actual load being less than the test period loads. In the absence of the EBA, this revenue loss could be at least partially offset by the additional secondary sales made with the resources not used to serve the retail load. However, the EBA requires that all revenue from secondary sales offset fuel-related net power cost in the calculation of the EBA. Therefore, under current regulatory practices the Company is penalized a second time as a result of this additional offset to the fuel-related net power cost. This situation was simply not contemplated at the inception of the EBA.

Q. What is the impact on the Company when actual retail loads exceed test period loads?

A. The benefit to the Company is symmetrical to the penalties of a retail load under-run. When retail loads exceed test period loads there is an increase in retail revenues related to the higher retail load. This higher retail load is reflected by lower secondary sales and related revenue. This creates a second benefit to the Company because secondary revenues offset fuel-related net power costs in the calculation of the EBA.

Q. What is the conclusion that you draw from this phenomenon?

A. The conclusion is that when retail loads are less than test period figures the Company suffers a double penalty. Conversely, when the retail loads are more than test period data the Company receives a benefit greater than the retail load over-run. The EBA was established to mitigate the impact on the ratemaking process of forecasting fuel-related net power costs in a volatile power market. Yet ironically, the EBA mechanism creates a phenomenon of benefit or penalty to the Company as retail loads fluctuate from test period levels. I believe the EBA should be terminated to eliminate this situation.

Q. Are there retroactive ratemaking questions raised by the EBA?

A. Yes. The application of the rule against retroactive ratemaking has been raised previously before this Commission. In 1986 the Utah Supreme Court disallowed a retroactive adjustment made to the EBA in 1982 based on the rule against retroactive ratemaking. From time to time other retroactive adjustments have been made to the EBA by way of Stipulation and/or Commission Order. None of these adjustments have been contested in the courts. It is not my intention here to draw a legal conclusion or to claim that such adjustments violate the rule against retroactive ratemaking. My purpose is to simply point out that if the EBA is not terminated, the issue of the legality of future adjustments to the EBA may require resolution.

Q. Does the issue of retroactive adjustments to the EBA present other problems for the Company?

A. Yes. The earnings impact of retroactive EBA adjustments is quite troublesome to the Company. Retroactive adjustments to the EBA have a direct impact on the current earnings of the Company. As long as the EBA is subject to retroactive adjustment, Company earnings must be considered somewhat uncertain for management purposes. This is a situation which certainly creates management uncertainty relative to the EBA and may lead to some uncertainty for users of the financial statements.

PROPOSAL FOR ELIMINATION OF EBA

Q. Mr. Topham, how does the Company propose to accomplish the termination of the EBA?

A. The first step in that process would be to file a revenue requirement in the second phase of this proceeding without the impact of the Energy Balancing Account. Simultaneously with the time prices from the second phase of this proceeding becoming effective, the current schedule 35 EBA collection rate would be terminated. The EBA collection rate would be rolled in with general tariffs that are produced from Phase II of this proceeding.

Q. What about the balance that exists in the EBA at that time?

A. Any balance payable to customers would be paid out in a one-time distribution in a manner similar to that proposed by the stipulation dated March 14, 1990 and approved by the Commission April 4, 1990 (Docket No. 90-035-03). Conversely, the Company would request that the Commission order that any balance receivable from customers, on the date of EBA termination, be established as a regulatory asset to be dealt with in an appropriate proceeding before the Commission.

Q. Mr. Topham, does this conclude your pre-filed testimony?

A. Yes, it does.

ICNU/204

Excerpt of Direct Testimony of
Mark T. Widmer in
Washington Utilities and Transportation
Commission Docket No. UE-050684

Exhibit No. ___(MTW-1T)
Docket No. UE-05_____
2005 PP&L Rate Case
Witness: Mark T. Widmer

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, vs. PACIFICORP dba Pacific Power & Light Company, Respondent.	Docket No. UE-05______

PACIFICORP

DIRECT TESTIMONY OF MARK T. WIDMER

May 2005

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

A. While there will be year-to-year volatility of wholesale market prices, the expected trend is up. Exhibit No.___(MTW-6) is the Company's Official Price Projection of future market prices.

Q. Has net power cost exposure been recognized and addressed in Washington and by other Commissions that regulate utilities located in the WECC?

A. Yes. As described in Ms. Omohundro's testimony, both PSE and Avista have PCAMs in place. Further, as discussed in the Standard and Poor's article included in Ms. Omohundro's testimony as Exhibit No.___(CAO-2), most of the investor owned electric utilities located in the WECC currently have some form of power cost recovery mechanism, with the exception of a few utilities including the Company and Portland General Electric (PGE). An important factor that should be considered in the Commission's evaluation of our request is the fact that the Company has more exposure than many of the other utilities located throughout the WECC because of the variability of hydro resources in our portfolio.

PCAM Structure

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

A. The PCAM is an incentive-based mechanism that would share variations in adjusted actual net power costs from the authorized baseline net power costs with one exception. The one exception is that 100 percent of cost increases or decreases related to Qualifying Facility contracts should be recovered from customers since the purchases are required by PURPA. All other costs would be subject to a symmetrical sharing mechanism that allocates 90 percent of cost increases and decreases to customers and 10% to shareholders. Mr. Duvall describes the steps necessary to allocate the deferrals to Washington pursuant to Revised Protocol.

Q. Does the proposed PCAM include any other adjustments in addition to the net power cost impacts?

A. Yes. The Company proposes that the retail revenue impact of changes in Washington retail loads from the level included in rates be accrued monthly to the PCAM account. The accrual would be calculated by multiplying the portion of the retail rate related to the production revenue requirement by the change in retail load. Under this approach, increased retail revenue related to load increases would be netted against increased net power costs and, conversely, revenue decreases related to declines in loads would be netted against decreased net power costs accrued to the PCAM account. The Company intends this provision to be equivalent to the "retail revenue adjustment" feature of Avista Corporation's Energy Recovery Mechanism (ERM).

Q. Please explain why the Company is proposing a higher sharing percentage in Washington (90%) than the Company is proposing in Oregon (70%).

A. The Oregon proposal includes a feature whereby the Company will be able to update its net power costs annually. Specifically, the Company has requested a Transition Adjustment Mechanism in Oregon to implement direct access consistent with the RVM mechanism approved for Portland General Electric. As part of the Transition Adjustment Mechanism (TAM), the Company would be able to update net power costs annually on a forecast basis and thereby significantly reduce regulatory lag. Because of the lag reduction, the Company requested sharing bands of 70 percent customers and 30 percent shareholders. Since a mechanism similar to the TAM does not exist in Washington, we are requesting the higher allocation to customers. Nonetheless, the Company will still have substantial incentives to keep costs as low as possible as a result of lag and the sharing band.

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

A. The baseline will be the authorized net power costs in effect during the measurement period. The measurement period should be tied to the balancing account trigger, which is discussed below. The baseline will be in effect until the Company's rates are adjusted through a general rate case.

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

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

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

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

Q. Is the Company proposing to establish a fixed schedule for requesting recovery or return of accrued balances to customers?

A. No. Rather than establishing a fixed schedule for such filings, the Company proposes that a plus or minus $5 million accrued balance on a Washington-allocated basis be established as a trigger. Once the trigger is reached, the Company will be required to return the balance to, or request recovery from, customers. This approach is more beneficial than setting a fixed schedule because it should reduce the number of rate changes during periods of lower net power cost volatility, reduce rate shock during periods of higher volatility when balances could be much higher, and provide more current price signals during periods of higher volatility. The Company proposes a one-year amortization period.

Q. Is the mechanism designed to take into account all NPC components?

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

Q. Please explain Exhibit No. ___(MTW-7).

A. Exhibit No.___(MTW-7) is an illustration of how the Company's proposed PCAM would have operated during calendar year 2004 assuming the net power costs authorized in Docket No. UE-032065 had been in effect for the entire year. As shown, the Total Company NPC variance from Washington authorized net power costs was $211.5 million. After exclusion of the Company's $21.5 million share, $27.8 was related to Company-owned West hydro, $8.9 million was related to Company owned East hydro, $3.1 million was related to Mid-Columbia hydro, $6.7 million was related to existing QF contracts, and $144.5 million was related to All Other, which includes fuel prices, market prices contract changes, etc. Washington's 90% allocated share of these costs would have been $18.1 million. The revenue impact of the load changes was $5.1 million, leaving a net Washington impact of $13.1 million.

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

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

Q. How does the Company propose to allocate the sur-charges and sur-credits to customers?

A. Mr. Griffith's testimony describes the Company's proposal.

Q. Could the specifics of this PCAM proposal be affected by the design of a decoupling proposal?

A. Yes. The direct testimony of Don Furman discusses the relation between the PCAM and decoupling.

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

A. If the Company's actual rate of return during the deferral period is above authorized levels, costs deferred during that period would not be recoverable. Conversely, if earned rates of return are below authorized levels, deferred balances owed to customers would not be returned.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 173

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Application for Approval of Power Cost	)
Adjustment Mechanism.	)

SUPPLEMENTAL TESTIMONY OF

MICHAEL GORMAN

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

October 17, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael Gorman and my business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, MO 63141-2000.

Q. WHAT IS YOUR OCCUPATION?

A. I am a consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. These are set forth in Exhibit ICNU/301.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I will discuss the risk reduction aspects of the approval of the Power Cost Recovery ("PCA") mechanism and explain why the reduction of PacifiCorp's risk by the implementation of this rider warrants a reduction to its authorized return on equity as approved in UE 170. Specifically, I recommend a 0.25% reduction to PacifiCorp's authorized return on equity, which would result in an approximately $4.2 million adjustment to PacifiCorp's Oregon revenue requirement. Second, I will comment on PacifiCorp's request to record a carrying charge on PCA deferrals if such a mechanism is implemented.

As explained in the direct and supplemental testimony of Randall Falkenberg, ICNU opposes PacifiCorp's PCA and Staff's PCA. However, my testimony explains why the Oregon Public Utility Commission ("OPUC" or the "Commission") should adopt an adjustment to PacifiCorp's authorized return on equity if the Commission adopts a PCA.

1. <u>RETURN ON EQUITY ADJUSTMENT</u>

Q. WHY DOES THE APPROVAL OF THE PCA REDUCE PACIFICORP'S RISK?

A. The implementation of the PCA reduces PacifiCorp's risk of under-recovering its power cost, and thus, reducies its risk of not earning its authorized return on equity. This risk reduction is significant. PacifiCorp witness Christy Omohundro's direct testimony at page 2 states that PacifiCorp's power cost represents 26% of its total Oregon retail revenue requirement. PPL/100, Omohundro/2. Historically, PacifiCorp has taken the risk of power cost recovery. Staff/100, Galbraith/10. PacifiCorp's proposal for a new rate setting mechanism will reduce its power supply cost recovery risk and will significantly enhance PacifiCorp's ability to earn its authorized common equity return. Under the PCA, this risk that PacifiCorp has historically borne is not eliminated, but is transferred to customers.

Q. DO THE PACIFICORP WITNESSES CONTEND THAT THE IMPLEMENTATION OF A PCA WILL REDUCE THE COMPANY'S RISK?

A. Yes. PacifiCorp witness Omohundro states that since the western energy power crises of 2001, wholesale market prices have fluctuated tremendously, sometimes as much as five to ten times the price fluctuations experienced prior to calendar year 2000. PPL/100, Omohundro/2. She states that the Company believes that power costs will continue to fluctuate in the future and, therefore, the Company is requesting to implement a power cost recovery mechanism in order to allow for changes in power costs between general rate cases. <u>Id.</u>

Further, she states that the implementation of a PCA is likely to be received positively by Standard & Poor's ("S&P") in its assessment of off-balance sheet debt like equivalents for purchased power agreement capacity contracts. Id. With the implementation of an automatic cost recovery mechanism, Ms. Omohundro states that S&P will likely reduce the risk factor used in its development of off-balance sheet debt equivalents. Id. This, in turn will have an implication on the appropriate capital structure needed by PacifiCorp to finance utility operations and preserve its credit quality.

Q. DOES THE IMPLEMENTATION OF THE PCA ELIMINATE THE POWER COST RECOVERY RISK?

A. No. It simply shifts this risk from PacifiCorp's investors to PacifiCorp's Oregon customers. Hence, it is appropriate to compensate customers for taking this risk by reducing the rates they pay PacifiCorp. Customers would be compensated for taking a risk by reducing retail rates by an amount equal to a reduced return on equity that reflects PacifiCorp's purchased power collection risk reduction. Such an adjustment would be balanced and fair, because it would continue to award PacifiCorp a fair return that reflects its risks, and that reflects the fact that some rate volatility risk is shifted to customers.

Q. HAVE ANY CREDIT RATING AGENCIES RECOGNIZED THE RISK REDUCTION OF THE POWER COST REDUCTION MECHANISMS?

A. Yes. S&P, for example, has stated that regulatory mechanisms that enhance the utility's ability to earn its authorized return on equity are afforded more weight than the actual level of authorized return on equity in the credit rating process. S&P states as follows:

> Although a higher authorized return on equity (ROE) may theoretically improve a utility's cash flow, a company's ability to actually earn the authorized ROE is more important for overall creditworthiness. The

> ability to earn an authorized ROE depends on adjustments included in rate-case decisions, and other regulatory mechanisms such as fuel-adjustment clauses.
>
> * * *
>
> Regulatory Mechanisms
>
> Certain regulatory mechanisms may be available to commissions that, if used, can strengthen a company's cash flow. Earnings and cash flow should improve if such mechanisms are used. Among the items that could require incremental recovery between rate cases are:
>
> - Fuel and purchased power costs.
> - Return on construction work in progress (CWIP).

Q. HAS PACIFICORP IDENTIFIED POTENTIAL IMPROVEMENTS TO CREDIT RATINGS BY THE IMPLEMENTATION OF A PCA?

A. Yes. In Ms. Omohundro's rebuttal testimony at 4, she states that S&P has reviewed PacifiCorp's lack of a fuel and purchased power adjustment mechanism as a serious credit concern that could potentially contribute to a credit downgrade. PPL/102, Omohundro/4. If Ms. Omohundro is correct, the opposite would certainly be true as well. The implementation of a PCA improves PacifiCorp's credit and reduces its risk. This is not to suggest that ICNU believes that a PCA should be adopted.

Q. IF A PCA WOULD REDUCE PACIFICORP'S RISK, WHY WOULD YOU NOT NECESSARILY SUPPORT THE ADOPTIONS OF SUCH A MECHANISM?

A. The PCA wouldn't simply eliminate risk, as stated above, but rather it would shift risk to customers. Hence, the relevant issue is who is best capable of managing the PCA price volatility risk – investors or customers.

Since PacifiCorp will be making the procurement decisions, it is more capable of managing its fuel and purchased power energy price risk than its retail customers. In many respects customers are simply unable to effectively engage hedging strategies to manage volatile PCA risk because they are not involved in PacifiCorp's procurement decision process.

Hence, from a value at risk standpoint, the Company is much more capable of managing its PCA risk exposure than are PacifiCorp's customers.

Q. IS THE RISK REDUCTION ASPECT OF THE PCA REFLECTED IN PACIFICORP'S 10.0% AUTHORIZED RETURN ON EQUITY?

A. No. The 10.0% authorized return on equity awarded in Order No. 05-1050 in UE 170 reflected PacifiCorp's current investment risk, which did not include a PCA. Hence, the 10.0% return on equity reflected in the Commission's final order in UE 170 must be adjusted in order to reflect the risk reduction to PacifiCorp and the risk increase to PacifiCorp's customers created by the implementation of a PCA.

Q. PLEASE EXPLAIN WHY PACIFICORP'S OREGON RETAIL CUSTOMERS' RISK WILL INCREASE WITH THE IMPLEMENTATION OF A PCA.

A. Again, as noted above, the risk of full cost recovery of volatile fuel and purchased power energy costs will not be eliminated with the PCA. Rather, the risk is simply shifted to customers from investors. Customers will assume this risk because PacifiCorp's cost of service will be impacted, not only by forward-looking volatile fuel and purchased power energy costs, but also by rate adjustments to provide recovery of PCA deferred balances. This price risk will create additional rate instability for PacifiCorp's retail customers, which will erode their ability to manage utility purchases and meet their own budgetary requirements.

Q. HOW DO YOU PROPOSE TO ADJUST PACIFICORP'S AUTHORIZED RETURN ON EQUITY OF 10% TO REFLECT THIS PCA RISK TRANSFER FROM INVESTORS TO CUSTOMERS?

A. An estimate of an appropriate return on equity adjustment should not only reflect a reduction to investors' risk by the creation of a PCA, but should also be adequate to fully compensate ratepayers for taking this risk. Customers are less able to manage this risk relative to the Company, and it is extremely difficult to estimate the appropriate return on equity adjustment that would be fair to both ratepayers and investors.

Hence, the most conservative means of estimating the ROE adjustment to reflect this risk shift from investors to ratepayers, would be to simply estimate what return on equity adjustment would be appropriate to reflect the reduced risk on investors. Note that this reduced ROE adjustment may not be adequate to fully compensate customers for taking this PCA risk, because they are not involved in the utility's fuel and purchased power energy procurement process.

The implementation of the PCA reduces PacifiCorp's cost recovery risk. In effect, it increases the likelihood that PacifiCorp will fully earn its authorized return on equity. One way to approximate the return value of this risk reduction, and shift the risk to customers, is to view the difference in utility bond yields with ratings of "A" and "Baa." An "A" bond yield reflects less cost recovery risk than a bond rating of "Baa." Hence, the difference in yield between an "A" and "Baa" bond yield proxies the market's valuation of utility cost recovery risk.

As illustrated on the attached Exhibit ICNU/302, over the 33-month period ending September 2005, the yield spread between an "A" rated utility bond and a "Baa" rated utility bond is 0.25%.

I recommend PacifiCorp's authorized return on equity of 10% be reduced by this 0.25%, to 9.75%, if PacifiCorp's PCA mechanism is approved.

Q. WOULD YOUR ESTIMATED 0.25% RETURN ON EQUITY ADJUSTMENT FAIRLY COMPENSATE CUSTOMERS FOR TAKING THIS PCA RISK?

A. No. As noted above, customers are not involved in the utility's fuel and purchased power energy procurement so they have limited to no options available to manage PCA price risk. For example, assuming no PCA is approved, if the Company knows the price of its normalized PCA cost built into its rates, it can execute market hedging strategies to lock in financial contracts, or supply contracts, in order to secure fuel and purchased power energy at prices that would fully recover the normalized base PCA costs.

In significant contrast, customers would not have the same opportunity to use financial and physical supply hedging contracts, because they would not be involved in the utility's procurement process, and would likely not be informed of the utility's procurement decisions until after they had been made. Hence, it is effectively impossible, or at least extremely difficult, for a customer to competently and successfully engage in energy procurement price risk management activities.

Hence, since customers are less able to manage the risk, the PCA risk to customers is greater than it is to the Company.

Therefore, a 0.25% return on equity adjustment is extremely conservative in that it does not fairly compensate customers for accepting the PCA risk. To fully compensate customers for taking this risk, the Commission should consider an ROE adjustment much higher than my estimated 0.25% investor return adjustment.

2. DEFERRAL CARRYING CHARGE CALCULATION

Q. ARE THERE ANY OTHER ASPECTS OF PACIFICORP'S PROPOSED PCA MECHANISM TO WHICH YOU WOULD LIKE TO RESPOND?

A. Yes. Staff suggested the Company may be permitted to accrue a carrying charge on PCA deferrals at its overall cost of capital. Staff/100, Galbraith/4. With respect to this proposal, I recommend that, if the PCA mechanism is approved, then the amount of the deferral subject to a carrying charge should be limited to the "after tax" balance of deferrals, and the carrying charge should be set at PacifiCorp's short-term debt cost.

Q. WHY SHOULD PCA DEFERRALS SUBJECT TO CARRYING CHARGES BE LIMITED TO THE AFTER TAX BALANCE?

A. The amount of PCA costs that should be subject to a carrying charge should be based on the amount of deferred PCA costs that will be carried by investor capital. PacifiCorp will be able to deduct on its income tax statements the fuel and purchased power energy costs in the year they are incurred, irrespective of whether rates are adjusted to ensure full recovery of those expenses in that year. Consequently, to the extent it under-recovers these costs in a year, it can deduct them for income tax purposes, and effectively reduce its income tax expense. The amount of net cash outlay PacifiCorp would experience in such a circumstance would be the unrecovered fuel costs, less the income tax reduction created because it did not fully recover its PCA expense in the year it was incurred.

PacifiCorp's net cash outlay would then be the unrecovered PCA cost, less the income tax savings. Investor capital will be needed to carry the after-tax deferral balance. The remainder would be carried by a deferred tax payable.

The carrying charge on deferred tax payments is zero percent. Hence, PacifiCorp's PCA deferral balance subject to a carrying charge should be based on its after tax cash outlay for deferral expenses, not the full amount of the deferred fuel expense balance.

Q. SHOULD THE INCOME TAX OFFSET TO THE DEFERRED PCA BALANCE BE BASED ON THE AMOUNT OF NORMALIZED INCOME TAX REFLECTED IN PACIFICORP'S OREGON RETAIL RATES?

A. Yes. The tax adjustment to the deferred PCA balance should reflect the amount of income taxes charged to customers and built into Oregon retail rates.

Q. WHY SHOULD THE PCA DEFERRED CARRYING CHARGE BE SET AT PACIFICORP'S SHORT-TERM DEBT COST?

A. I oppose the Company's proposal to carry this deferred balance at its overall cost of capital. The overall cost of capital should be made applicable only to long-term assets. PCA deferrals are not a long-term asset, but are rather short-term in nature. Consequently, the carrying charge applied to these deferrals should be based on PacifiCorp's short-term borrowing cost, not its long-term cost of capital.

Another reason why the short-term borrowing cost should be applied to short-term assets, such as PCA deferral balances, is that the actual amount of deferral can increase or decrease as the Company over- or under-recovers its PCA cost due to variations in fuel and purchased power energy costs throughout the year. If the deferral balance itself is increasing and decreasing each month, then it would be appropriate to use a flexible financing source that can be increased or paid down on a monthly basis to ensure the balance of the capital supporting the deferral can be matched with the actual balance of the deferral. This practice will minimize PacifiCorp's actual cost of carrying the deferral.

Short-term borrowing sources can be increased and decreased each month to coincide with the balance of deferral, and thus this is the most prudent PCA deferral financing vehicle.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ICNU/301

Michael Gorman Qualifications

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Michael P. Gorman. My business mailing address is P. O. Box 412000, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a consultant in the field of public utility regulation and a managing principal with Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. In 1983 I received a Bachelors of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. In April 1995 the firm of BAI was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements. Continuing, I have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona; Chicago, Illinois; Corpus Christi, Texas; and Plano, Texas.

Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the regulatory commissions in Arizona, Delaware, Georgia, Illinois, Indiana, Iowa, Michigan, Missouri, New Mexico, New Jersey, Oklahoma, Oregon, Tennessee, Texas, Utah, Vermont, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta and Nova Scotia, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q. PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A. I earned the designation of Chartered Financial Analyst ("CFA") from the Association for Investment Management and Research ("AIMR"). The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of AIMR's Financial Analyst Society.

ICNU/302

Utility Bond Yield Spread

PacifiCorp

Utility Bond Yield Spread

Line	Date	A (1)	Baa (2)	Yield Spread (3)
1	Jan-03	7.06%	7.46%	0.40%
2	Feb-03	6.92%	7.15%	0.23%
3	Mar-03	6.80%	7.06%	0.26%
4	Apr-03	6.65%	6.96%	0.31%
5	May-03	6.35%	6.46%	0.11%
6	Jun-03	6.23%	6.32%	0.09%
7	Jul-03	6.52%	6.60%	0.08%
8	Aug-03	6.77%	7.06%	0.29%
9	Sep-03	6.52%	6.83%	0.31%
10	Oct-03	6.43%	6.78%	0.35%
11	Nov-03	6.36%	6.68%	0.32%
12	Dec-03	6.22%	6.55%	0.33%
13	Jan-04	6.15%	6.47%	0.32%
14	Feb-04	6.15%	6.28%	0.13%
15	Mar-04	5.97%	6.12%	0.15%
16	Apr-04	6.35%	6.46%	0.11%
17	May-04	6.62%	6.75%	0.13%
18	Jun-04	6.46%	6.84%	0.38%
19	Jul-04	5.98%	6.36%	0.38%
20	Aug-04	6.12%	6.42%	0.30%
21	Sep-04	5.99%	6.28%	0.29%
22	Oct-04	5.98%	6.17%	0.19%
23	Nov-04	5.96%	6.15%	0.19%
24	Dec-04	5.91%	6.09%	0.18%
25	Jan-05	5.78%	5.95%	0.17%
26	Feb-05	5.61%	5.76%	0.15%
27	Mar-05	5.83%	6.01%	0.18%
28	Apr-05	5.64%	5.95%	0.31%
29	May-05	5.53%	5.88%	0.35%
30	Jun-05	5.40%	5.70%	0.30%
31	Jul-05	5.51%	5.81%	0.30%
32	Aug-05	5.51%	5.83%	0.32%
33	Sep-05	5.55%	5.87%	0.32%
34	**Average**	**6.15%**	**6.40%**	**0.25%**