BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 173

In the Matter of)

PACIFICORP,)

Application for Approval of A Power Cost Adjustment Mechanism.)

OPENING TESTIMONY

OF THE

CITIZENS' UTILITY BOARD OF OREGON

August 19, 2005

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 173

In the Matter of PACIFICORP, Application for Approval of A Power Cost Adjustment Mechanism.	))))))))	OPENING TESTIMONY OF THE CITIZENS' UTILITY BOARD OF OREGON

My name is Bob Jenks, and my qualifications are listed in CUB Exhibit 101.

I. Introduction

There are several core issues in this docket:

- Is a power cost adjustment mechanism necessary and fair for PacifiCorp?
- What is the relationship between a power cost adjustment mechanism and the Revised Protocol that grew out of the multi-state process?
- Is the specific PCAM proposed by PacifiCorp one that provides a just and reasonable balance between shareholders and Oregon customers?

In this testimony, we will show that a PCA is not necessary for good ratemaking, but a PCA targeted towards extraordinary risks, such as severe hydro conditions, plant failures, or extreme market conditions is not unreasonable.

We will also show that the Revised Protocol focused on allocating *normalized* power costs for general rate cases; on the other hand, a PCA, by design, is concerned with *non-normalized* power costs. This means that the Revised Protocol is not applicable, and does not require Oregon to follow any allocation methodology for a PCA. However, if the Commission wanted to allocated non-normalized power costs consistent with the Revised Protocol, such an allocation would be significantly different than what the Company has proposed, since the Revised Protocol allocates hydro replacement costs system-wide, and requires that allocation factors be updated.

We will show that PacifiCorp's proposed mechanism is seriously flawed. The proposal asks Oregon customers to subsidize power costs that will be incurred to serve Utah load, while at the same time asking Oregon customers to pick up a disproportionate share of hydro-related costs. This combination guarantees that Oregon customers will be unfairly overcharged by the mechanism. The mechanism would lead to frequent rate changes. Furthermore, the proposed treatment of Qualifying Facilities (QFs) does not have a rational basis. Finally, the lack of a deadband allows PacifiCorp's shareholders to shift unreasonable risk to customers. Oregon has traditionally recognized that shareholders absorb some of the normal variation (both positive and negative) that happens between rate cases, before shifting that risk to customers.

In closing, CUB proposes an alternative PCA. CUB's proposal is a much less radical shift of traditional risk than the Company is proposing. But CUB's proposal recognizes that, under certain conditions, Oregon regulation has allowed extraordinary costs to be shifted from shareholders to customers. Rather than waiting for those extraordinary circumstances to occur and then beginning a highly-contested docket to address the mechanism to account for the costs from the circumstance, an established

PCA that dealt with such circumstances would eliminate repetitious deferral filings. This would be a positive outcome to this docket.

II. Is A PCA Necessary Or Fair?

In Oregon, utilities have historically taken the risk of cost changes between rate cases. Some costs go up, some costs go down, and the utilities bear the risk and reap the reward for these changes. In the 1990s, when fuel costs were declining, wholesale power was inexpensive and the hydro system was consistently producing above forecasts, the utilities were very happy with the way Oregon - without a power cost adjustment - allowed them to keep the benefits associated with the cost changes of power operations between rate cases.

Times change. Today, with record gas costs, low hydro, and volatile wholesale power prices, utilities have been aggressive in seeking power cost adjustment mechanisms and deferrals. In their filings, utilities typically cite the need to do this for their standing in financial markets. In this filing, PacifiCorp cites a Standard & Poor research article as proof of its need for such a mechanism:

> In a recent Standard & Poor research article titled “Fuel and Power Adjusters Underpin Post-Crisis Credit Quality of Western Utilities”, it states that PacifiCorp’s lack of a fuel and purchased power adjustment is a credit concern (PPL Exhibit 101, page 2).

PPL/100/Omohundro/3.

But the article is a little more nuanced than PacifiCorp suggests. The article’s focus is on fuel and purchased power, and it calls for Fuel and Purchased Power Adjustment Mechanisms (FPPA) for at-risk utilities:

> The overwhelming majority of a utility’s expenses are concentrated in two categories—purchased power and fuel. Electric utilities that have the greatest exposure to significant cost swings are those that have

> sizable gas-fired generation and rely on power purchases that are indexed to market prices...
>
> Because about 21% of PacifiCorp's power in 2003 came from purchases, the lack of an FPPA is a credit concern.

PPL/101/Omhundro/1-2.

First it should be noted that in relation to S&P's first concern, sizable gas-fired generation, PacifiCorp is in a relatively good position. The Company's 2006 forecast projects 3 million MWh of gas generation, which is a small fraction of the Company's coal-fired generation, 45 million MWh. CUB Exhibit 102.[1] With regard to the second concern, purchased power that is indexed to market prices, PacifiCorp's exposure is also limited. The 21% of PacifiCorp's 2003 power that was cited by S&P was not limited to power purchases that were indexed to market prices, but included Mid-Columbia hydro.

In 2006, the Company projects a Retail Load of 56.1 million MWh. The Company's coal, gas, wind, hydro, and Mid-Columbia purchases are 54.9 million MWh. This leaves the Company short by 1.2 million MWh, or about 2% of its retail load. CUB Exhibit 102.[2]

Of course the Company makes additional purchases, but these purchases are offset by the Company's sales. PacifiCorp makes 4 million MWh in Special Sales for Resale (a number that continues to decline), and about 5 million in Firm Sales, and 5 million more in System Balancing Sales.

Generally speaking, PacifiCorp is in relatively good load/resource balance, without having a great deal of gas generation. Its need to service the Sales for Resale

---

[1] UE 170 - PPL/801/Weston/5.1.6-5.1.7.
[2] UE 170 - PPL/801/Weston/5.1.6-5.1.7.

Contracts continues to decline. It is working to acquire additional resources that will meet its load growth without making it more dependent on the market.

While the Standard & Poor article did suggest that a lack of a FPPA was a credit concern with PacifiCorp, it was based on PacifiCorp having been exposed to the market for 21% of its power which, when placed in context, is overstated.

The S&P report also notes that PGE's RVM mechanism, combined with the ability to request deferrals in Oregon, operates as a quasi-FPPA. PGE has a:

> quasi-FPPA; i.e., rates are updated annually through a resource valuation mechanism process, but if during the year the utility is unable to collect all of its costs through rates, it must make a special filing before the commission to recover the shortfalls.

PPL/101/Omohundro/5.

Finally, it should be noted that the S&P report cites the Washington PCAs as examples that are tied to financial thresholds. Avista has a deadband of $9 million that the Company must absorb before getting any recovery. PSE must absorb the first $20 million. CUB Exhibit 103 shows that these deadbands represent 2.3% of revenue and 1.5% of revenue, respectively. A deadband of 2.3% of revenue would equal almost $20 million for PacifiCorp. This is a much less generous PCA than the one proposed by the Company.

All of this suggests that the case for a PCA as generous as that proposed by PacifiCorp has not been made. In fact, it is not clear that a PCA is necessary at all. That being said, we believe there is a reason to grant a PCA to PacifiCorp. As the S&P paper reports, utilities in Oregon can request deferral of excess power costs. Power Cost Deferral dockets have been filed by a number of utilities in recent years. They can become contentious and time consuming. Rather than handle such deferrals on a case-by-case basis, we think it would be better to use a PCA as a way to establish the rules of the game for deferrals ahead of time. We believe this is consistent with the extreme-event type of PCA recommended by Staff and cited by the Commission in its UM 1071 order.

III. Relationship Between A PCA & The Revised Protocol

PacifiCorp claims that its mechanism is based on the Revised Protocol. There are two problems with this: First, the Revised Protocol was an investigation and negotiation into how to allocate normalized power costs. There was no attempt to investigate allocation of the non-normalized power costs that are at issue in a power cost adjustment mechanism. Second, even if the goal were to allocate non-normalized power costs based on the Revised Protocol, the result would be significantly different than what is proposed by PacifiCorp. The Revised Protocol requires that hydro replacement power costs be allocated system-wide, and that allocation factors be updated; the Company's proposed mechanism does neither.

A. Revised Protocol Does Not Address Non-Normalized Power Costs

Traditional ratemaking is based on normalized costs. The Multi-State Process was a review and negotiation of the allocation of normalized power costs for the purpose of ratemaking. It did not involve a review, modeling, discussion, or negotiation of non-normalized power costs, which would be the subject of a power cost adjustment. CUB Exhibit 104[3].

In its rebuttal testimony in support of the Revised Protocol, the Company stated that discussions "resulted in a Stipulation between three Oregon parties and PacifiCorp to support the use of the Revised Protocol for purposes of general rate proceedings in

[3] PacifiCorp response to CUB data request 1.

Oregon."[4] During the many months of discussions, studies, negotiations, and regulatory proceedings that were involved in the Multi-State Process, there were never any discussions about the use of the Revised Protocol outside of general, normalized rate cases, including how the Revised Protocol related to power cost variations that occur between rate cases, which is the function of a power cost adjustment. From Oregon's perspective, such a discussion would have been irrelevant. Non-normalized power costs have generally been the responsibility of the Company.

There was a great deal of discussion during the MSP about whether slow-growing states such as Oregon subsidize Utah which is a fast-growing state. PacifiCorp did a series of model exercises to examine this, and the modeling concluded that much of the subsidy that was created by Utah load growth was offset by the reduction in the allocation factors relating to system overhead and by allocating summer peaking resources to seasonal load. There were never any studies, however, that looked at load-growth subsidies from a perspective of non-normalized power costs. Normalized summer peak costs can be significantly less than actual summer peak costs. Is there a subsidy associated with allocating non-normalized summer peaking costs system-wide? Is it offset by something else? These questions were not asked, they were not studied, and MSP negotiators did not address them.

Having adopted the Revised Protocol, the Commission is expected to use it as a basis for allocating normalized power costs in general rate cases, unless doing so would not result in just and reasonable ratemaking. However, because the Revised Protocol does not prescribe any particular allocation method for non-normalized costs, the Commission is free to adopt whatever allocation methodology it finds appropriate for the non-

[4] UM 1050 - PPL/204/Kelly/2.

normalized power costs addressed in a PCA. For example, there was a great deal of discussion in the MSP of using the Hybrid model for allocating power costs, but due to opposition from other states, primarily Utah, the Hybrid was rejected. However, under the Revised Protocol, Oregon could use the Hybrid as a basis for a PCA. The Revised Protocol does not prescribe a method for allocation of non-normalized costs, and it does not require Oregon to adopt a particular method.

B. PacifiCorp's Proposal Doesn't Allocate As Revised Protocol Would

While the Commission is free under the Revised Protocol to adopt any methodology it wants to allocate non-normalized power costs, it is not unreasonable to seek consistency with the Revised Protocol in such allocations that are not covered by the Protocol. Unfortunately, the Company's proposal is not consistent with the Revised Protocol with respect to hydro-related replacement power costs or the updating of allocation factors.

While claiming that its "primary principle was to ensure that the inter-jurisdictional cost allocation for the PCAM be consistent with the allocations under the Revised Protocol," the Company offers no support to show that its allocation methodology is, indeed, consistent. In some cases the Revised Protocol is clear as to how it applies in certain circumstances, but in other places it is not. Where the Protocol itself is not clear, the parties should look at the record of the UM 1050 proceeding to see if that record is clear. The Revised Protocol says directly that parties will attempt to resolve questions of interpretations "with reference to the intent of the parties who have supported the ratification."[5]

[5] OPUC Order 05-021, Attachment A, pp. 22-23.

i. Replacement Power Costs For Hydro Variation

In its PCA proposal, PacifiCorp uses a series of GRID runs to assign costs. It assigns 57.8% of what it models to be the replacement power costs associated with Company-owned hydro generation in the West to Oregon, and 69.7% of the replacement power costs associated with Mid-Columbia contracts to Oregon[6]. The only explanation given for this assignment is that it is "consistent with the initial allocation of the costs and benefits under the Revised Protocol."[7]

In response to our data request, the Company suggests that this allocation is what the Oregon parties intended:

> While there was no explicit modeling of the effect of non-normalized power costs, there was an express recognition by the Oregon parties that departing from a rolled-in method and allocating a greater share of hydro resources to Oregon customers could increase price volatility to Oregon customers. Representatives of CUB and the Oregon staff regularly assured other MSP participants that this was a risk they were willing to take in order to obtain a hydro endowment.

CUB Exhibit 104 – PacifiCorp Response to CUB Data Request 1.

Excuse me? CUB and other Oregon parties certainly did advocate for dedication of hydro resources to the Northwest states. That was a significant part of our advocacy for the Hybrid approach. But that approach was rejected by Utah and abandoned by PacifiCorp in light of Utah's rejection. What we advocated for was not what we got. What we got is a compromise that gives Oregon less than the full value of hydro, but that allocates hydro replacement power costs equally across the system.

What we got was the Revised Protocol. It does not assign the hydro production from hydro facilities to the hydro states. Instead it establishes an adjustment to reflect our

---

[6] PPL/204/Widmer/2.
[7] PPL/300/Duvall/3.

historic contribution to the fixed costs of the hydro through the Hydro Endowment. The Hydro Endowment uses an embedded cost approach to determine a credit to Oregon customers based on the value of hydro under normalized conditions. This was not our preferred approach, but was accepted as part of a compromise.

That compromise requires Oregon to pay tens of millions of dollars for existing QFs. It does not provide Oregon with the benefits of hydro when used for reserves. It requires that Hydro Endowment states pay for the direct costs of relicensing hydro facilities. The value of the Hydro Endowment declines as the output declines due to relicensing and Mid-Columbia contract renewal. It *does not require* us to bear the cost of replacement power costs as hydro declines. It does require that we pay a significant share of Utah's load growth. Utah's load growth is supposed to be offset by reductions in the allocation of system overhead caused by the relative growth of the two states, but, as the Company pursues mechanisms such as the RVM and this PCA that assign load-growth costs in real time without adjustments to system overhead, this offset is reduced.

In their UM 1050 rebuttal testimony, the Company acknowledges that the hydro costs we agreed to take on were the ones related to relicensing. According to that testimony the MSP agreement represents the Oregon Coalition members' "willingness to accept the costs and risks of hydro relicensing in exchange for an expanded Hydro Endowment."[8]

There was a great deal of discussion during the MSP concerning the benefits and risks associated with hydro generation as allocated through the Hydro Endowment. The Revised Protocol was a compromise. CUB and other Oregon parties believed that the Revised Protocol failed to provide us with the full financial benefits associated with

[8] UM 1050 – PPL/204/Kelly/10.

hydro resources, such as the value of the reserves that hydro provides to the system. According to Staff, the value of these hydro reserves between 2005-2018 is $150 million, but the Revised Protocol short-changes Oregon for the value of these reserves by $49 million[9]. We also recognized that there are costs associated with hydro generation that the Revised Protocol did not assign to the Hydro Endowment states, such as the cost of replacing hydro power when hydro conditions are below normal.

Replacement power costs for low hydro generation is a system cost that is shared by all states:

> More specifically, while Oregon is entitled to a disproportionate share of the benefits of the hydro resources, it is not required to pay all the costs associated with these resources. Contrarily, the costs to replace the generation capacity that PacifiCorp's hydro resources will lose in the future due to loss of license, contract expiration or reduced project capability, will be dynamically allocated system-wide.

UM 1050 - Joint Brief of PUC Staff & CUB, page 20, filed with the Commission 9/7/04.

> Q. Are all costs associated with the hydro resources included in the calculation of benefits?
>
> A. No. Parties in Utah and PacifiCorp note that the cost of replacing lost generation (Issue #2) due to loss of license, contract expiration, or reduction in project capability is allocated system wide rather than assigned to the states receiving the benefit of the lower cost Company-owned generation.
>
> Q. Do you agree with this perspective?
>
> A. Yes. When the amount of hydroelectric resources is reduced due to relicensing requirement, contract expiration, retirement or other factors, such as poor hydro conditions, the Company must replace the lost power. The cost of that replacement power is included in power costs and allocated to all states.

UM 1050 - Staff/100/Hellman/20, filed with the Commission 7/2/04.

---

[9] UM 1050 - Staff/200/Wordley/3-4.

The customers that receive the benefits of the Hydro Endowment bear the direct costs associated with hydro relicensing and renewal of the Mid-Columbia contracts. If the renewal requires fish ladders, we pay the costs. If the renewal reduces the normalized output of the facility, the value of the Hydro Endowment is reduced, but the cost of replacement power is not assigned to the customers that receive the benefit of the Hydro Endowment. The testimony before the Commission in support of the Revised Protocol is clear on this; replacement power for reduced hydro generation due to poor hydro conditions is allocated on a system-wide basis. If the Company and other States wanted us to bear the cost of replacement power, they should have agreed to the Hybrid which would have placed this cost on the Northwestern states.

ii. Updating Allocation Factors

PacifiCorp proposes that costs under the PCAM be allocated based on the allocation factors used to forecast power on a normalized basis. The Oregon Stipulation, however, requires that we use an updated allocation factor:

> Oregon Parties have been concerned that relatively faster-growing States cause other States to unreasonably support the costs associated with that faster load growth. Load-Based Dynamic Allocation Factors cause costs to be shifted to relatively faster-growing States. However, in order to insulate slower-growing States from the consequences of faster load growth in other States, rates in relatively slower-growing States should incorporate relatively current Load-Based Dynamic Allocation Factors, which reflect an appropriate level of relative cost responsibility.

UM 1050 - Order No. 05-021, Attachment A, page 3.

It makes little sense to allocate actual power costs based on each state's forecasted load when actual loads are available, and would better meet the Stipulation's call for "relatively current" allocation factors.

It is not just semantic adherence to the Stipulation that concerns us, however. The purpose of updating allocation factors is to reduce the subsidy that Oregon pays for Utah load growth. Using the most current load-based allocation factors is a way to reduce this subsidy.

CUB Exhibit 105[10] shows that during the five years of available data, 2000 through 2004, PacifiCorp under-forecasted Utah's load by an average of 874,460 MWh, while over-forecasting Oregon's load by an average of 132,105 MWh. This means that Oregon's share of the system in relation to Utah's is smaller than is typically forecast, because PacifiCorp under-forecasts Utah's load while over-forecasting Oregon's load. If we update allocation factors, Utah's share of actual cost will increase, and Oregon's will decrease. In each of the 5 years from 2000 to 2004, Oregon's actual load was a smaller share of the system load than was forecast.

The above phenomena no doubt reflects a number of factors. It is probably more difficult to forecast rapid load growth than it is to forecast slow load growth. In addition, Utah probably experiences larger weather deviations than Oregon. CUB Exhibit 106[11] shows that Utah Power's peak demand this summer was 20% greater than was forecast. CUB Exhibit 107[12] shows that this was primarily due to hot weather. Regardless of the cause, actual Utah load is more likely to be greater than forecast than is Oregon load; updating allocation factors would be a way to account for this phenomenon.

PacifiCorp Exhibit 204 shows how the Company's proposed mechanism would work if applied to FY 2004. The Company could point out that, based on the actual loads in FY 2004, Oregon's allocation of costs would be reduced by only $600,000.

[10] Calculations based on PacifiCorp's response to CUB data request 4.
[11] PacifiCorp response to CUB data request 2.
[12] PacifiCorp press release about Utah's peak load on July 12, 2005.

CUB Exhibit 108.[13] In 2004, however, Utah load was actually *below* forecast by 531,087 MWh. CUB Exhibit 105.[14] Remember, though, that Utah load was above forecast by 874,460 MWh on average from 2000 to 2004, so the 2004 forecast is the outlier, not the trendsetter. In other words, though 2004 is included in the above average, the average shows that under-forecasting of Utah load is the norm, despite the 2004 over-forecast. CUB asked the Company to provide additional back-casts of the PCAM for the years 2002 and 2003, but the Company was unable to provide them.

It is clear that the Revised Protocol requires the use of "relatively current" load-based allocation factors in order to minimize Oregon's subsidy of Utah's load growth. It is also clear that using actual loads under non-normalized circumstances, such as those covered by a power cost adjustment mechanism, would better meet the intent of the Revised Protocol and minimize Oregon's subsidization of Utah's load growth.

IV. The Company's Proposed Mechanism Is Not Reasonable

In recent years, we have participated in a number of discussions and proceedings related to power cost recovery through deferrals and power cost adjustment mechanisms. It is disappointing to us, therefore, that we continue to see utility proposals as flawed as this one, when so much time has already been spent on this effort.

PacifiCorp's proposal is decidedly lacking in evidence to support the necessity of a power cost adjustment mechanism in the first place, but it is even more lacking in evidence supporting the Company's proposed mechanism itself. In many respects, the details of the mechanism simply exist, with no real explanation as to why the Company made the policy choices that it did. The Company did make a number of policy choices,

[13] PacifiCorp response to CUB data request 5.
[14] Calculations based on PacifiCorp's response to CUB data request 4.

though, and they were choices that were both beneficial to the Company and choices the Company must have known would be opposed by CUB and other parties. Most importantly, these policy choices have created a mechanism that is so flawed that the proposed mechanism cannot be used as the basis for reasonable PCA.

A. PacifiCorp's Proposed Mechanism Has No Deadband

It is not clear to us why PacifiCorp proposed no deadband. After several years of discussion, they must recognize that such a proposal is a non-starter for other parties. In looking at recent PCA and power cost deferrals it is immediately clear that they do not set a precedent for a mechanism as generous to a utility as what PacifiCorp is proposing. Rather than offering a mechanism to bridge the gap between the parties, PacifiCorp has staked an extreme position.

i. Oregon Precedent Does Not Support Such A Generous Mechanism

A recent Commission decision that addressed hydro and power cost variability was UM 1071, PGE's 2003 hydro deferral. In that docket, PGE proposed a 95/5 sharing mechanism, where 95% of the changes in Net Variable Power Costs would fall on customers. OPUC Order 04-108. Contrasting PGE's deferral application, which contains a certain amount of regulatory lag, to PacifiCorp's PCAM proposal which, by definition has no regulatory lag, serves to highlight the inappropriateness of PacifiCorp's deadband omission. PGE's deferral application, because of the regulatory time lag between the beginning of the year and the date upon which the Company filed, would have left PGE absorbing 18% of the cost of replacing low hydro; not unlike a deadband in a PCA. OPUC Order 04-108. Yet the Commission rejected PGE's filing, and instead suggested that the "parties might present a PCA proposal similar to the one Staff outlined here."

OPUC Order 04-108. Staff's proposal was for a PCA that protected the Company from extreme events only.

In UE 115, the Commission granted PGE a PCA with a deadband of plus or minus $28 million and sharing bands that began at 50%. In UM 1008 and UM 1009, the Commission granted PGE a deferral with a deadband of $35 million and sharing bands that began with 50/50 cost sharing. In UM 995, the Commission granted PacifiCorp a deferral with a deadband of 250 basis points of return on equity, a 50/50 sharing band between 250 and 400 basis points of return on equity, and a 75/25 sharing band above 400 basis points of return on equity.[15] In UM 1198, the parties settled on a deferral for Idaho Power with a deadband equivalent to 250 basis points of return on equity, a 50/50 sharing band between 250 and 400 basis points, and an 80/20 sharing band above 400 basis points.[16]

ii. Regional Precedent Does Not Support Such A Generous Mechanism

Oregon is not out of the ordinary. As mentioned earlier, Washington has PCAs for PSE and Avista. PSE's power cost adjustment has a deadband of $20 million, and Avista has a PCA with a deadband of $9 million.[17] Based on these companies' Washington revenues, as reported by the Washington Utilities and Transportation Commission, this represents approximately 1.5% and 2.3% of the companies' Washington revenues respectively. CUB Exhibit 103.

iii. Utility Takes The Risk & Reward Of Cost Variation Between Rate Cases

Under traditional regulation, we set rates based on a normalized, forecasted test year. We know that our forecast will be off. Some costs and revenues will be greater than

[15] UM 995 - OPUC Order 01-420, page 5 & 29.
[16] UM 1198 - OPUC Order 05-870, Appendix A, page 3.
[17] PPL/100/Omohundro/3-4.

we project and some will be lower than we project. Utilities earn a return on equity to compensate them for the risk they take of cost changes between rate cases.

While a PCA would seem to be fundamentally at odds with this concept of traditional ratemaking and return on equity, by absorbing the traditional risk through a deadband, we can provide a PCA that maintains the traditional risk, while pre-approving the rules for recovery outside of that risk. This will avoid the need for a deferral when conditions might warrant a deferral.

iv. Deadband Absorbs The Impact On A PCA Of Load & Revenue Changes

When the Company has a power cost increase due to increased load (such as from hot summer weather, cold winter weather, or increased economic activity) it also has a revenue increase because customers pay for that increased load. This revenue increase helps to offset the increased costs. Likewise, if the Company experiences a power cost decrease due to decreased load, it will also collect less revenue which offsets the decreased cost. Allowing the Company to charge customers for higher costs due to an increase in load, without recognizing that the load increase also brings additional revenue from customers, results in the Company charging customers twice for the same power cost increase.

Likewise, to refund to customers revenues associated with reduction in costs due to decreased load without taking into account that for each kilowatt hour of reduced costs from not serving load there is also a kilowatt hour of revenue that was not paid to the Company, requires the Company to refund income that it never received. PGE tried to fix this in their power cost adjustment mechanism in UE 115 by having a revenue adjustment mechanism included in the PCA. That mechanism greatly complicated the PCA, led to a great deal of dissatisfaction, and led to the elimination of the PCA after a single year.

A better approach to dealing with the revenue side would be a significant deadband that would help neutralize the effect of revenue changes. We do not have to worry about overcharging customers or over-refunding money to customers, if we have a significant deadband.

v. PacifiCorp's $15 Million Threshold Is Not A Deadband

PacifiCorp proposes that no rate changes occur until a $15 million threshold is reached, but this is not the same as a deadband. A deadband represents costs that the Company absorbs, as opposed to PacifiCorp's proposal wherein customers absorb all costs. The $15 million threshold only changes the timing of when customers pay, delaying it until the balance reaches the threshold; it does not, however, change the ultimate amount paid by customers.

B. The Company's Proposed PCAM Over-Allocates Costs To Oregon

The PCAM has serious design flaws that lead it to over-allocate costs to Oregon. On a normalized basis, Oregon was allocated 30.4% of net power costs that were used to set the baseline. According to the Company's Exhibit 204, Oregon is being allocated 37% of the total PCAM adjustment.

During FY 2004, covered by PacifiCorp Exhibit 204, Oregon only represented 27% of the actual load. CUB Exhibit 109.[18] If we are allocated 30% of the normalized costs and 37% of the excess costs, when we actually only represent 27% of the system load, then we are being charged more than our fair share of the system costs.

[18] PacifiCorp response to CUB data request 12.

For power costs we see the same thing. On a normalized basis, Oregon is charged more than other states. Our average cost is $13.14 per MWh and the system's average cost is $11.24 per MWh. We are charged $1.9 more per MWh than the average system cost. However, the PCAM would increase the average system cost by $2.86/MWh while Oregon's average cost would increase by $3.10/MWh. After the PCAM, Oregon customers would be charged $16.24/MWh in net power costs, while the average system cost would be $14.10/MWh. CUB Exhibit 109.[19]

Some of this can be explained by the assignment of the costs of existing QFs to the states where those contracts originated. But that does not come close to accounting for the larger assignment of costs to Oregon through the PCAM. According to PacifiCorp Exhibit 204, the costs of QFs make up less than 2% of the variance allocated through the PCAM. This does not account for Oregon being charged 37% of the variance when we are 27% of the load.

i. PacifiCorp's PCAM Overcharges Oregon For Utah Costs

In its PCAM, PacifiCorp proposes that Oregon customers be allocated a share of the hydro replacement power costs based on our share of the Hydro Endowment, while also paying 28% of other costs, such as the cost to meet a hot weather event in Utah. The 28% is Oregon's share of the system load under normalized conditions. This simply does not add up. If the hydro resources are dedicated to Oregon, and Oregon customers have to compensate for any hydro kilowatt hour not generated, then we cannot also be responsible for 28% of the remaining system load. Put another way, Oregon is 28% of the system load, so if Oregon pays for lost hydro MWh, then Oregon's remaining share of

[19] PacifiCorp response to CUB data request 12.

the system load must be less than 28%; it should be 28% minus the percentage of our load that is served by dedicated hydro.

CUB Exhibit 110[20] shows that if PacifiCorp gave Oregon customers credit for the hydro that the Company's mechanism dedicated and charged to them, then we would only represent 22.5% of the remaining system load. Of course, that is not what PacifiCorp is proposing. Instead, the Company is asking Oregon customers to pay for hydro shortfalls as if hydro were dedicated to us, while also paying for increased system costs as if costs were allocated on a system-wide rolled-in basis. If hydro MWh and associated costs are dedicated, then other costs cannot be allocated on a fully rolled-in basis. If the system costs are rolled-in, then hydro MWh aren't dedicated. Pick one or the other, but don't nail Oregon customers with both.

ii. PCAM Ignores Impact Of Oregon Load In Reducing Oregon Costs

One of the design flaws of the PCAM is the way in which it calculates the cost of replacing hydro shortfalls. PacifiCorp Exhibit 204 identifies a 1.5 million MWh hydro shortfall and uses three GRID runs to calculate the replacement cost: Run 1 updates for actual market prices, Run 2 adds an update for actual Company-owned hydro generation, and Run 3 updates for actual Mid-C hydro generation. The PCAM uses the difference between Runs 1 & 2 to identify the cost of replacing Company-owned hydro, and the difference between Runs 1 & 3 to identify the cost of replacing Mid-Columbia hydro.

Unfortunately, because these GRID Runs are done on a normalized basis, they tell us little about the *actual* cost of replacing hydro generation. In Exhibit 204, the Company has a hydro shortfall of 1,528,057 MWh[21], but in 2004, the load it served was

[20] PacifiCorp response to CUB data request 10.
[21] PPL/204/Widmer/1.

859,504 MWh below forecast. CUB Exhibit 105.[22] This means that the Company did not have to replace the entire hydro shortfall, it only had to replace the difference between the hydro shortfall and the load shortfall. The normalized GRID runs, however, do not account for the reduced load, and so tell us nothing about how the system was dispatched to meet the actual load under actual hydro conditions.

In 2004, Oregon load was down by more than twice the amount of the decrease in the system load of 651,237 MWh. This represents 42.6% of the total company-wide hydro shortfall. Using the allocation factors the Company assigns to Hydro-West, Hydro-East, and Mid-Columbia, Oregon's allocated share of the hydro shortfall is 800,904 MWh, before applying the sharing band. This means that more than two thirds of Oregon's share of the hydro shortfall is offset by Oregon's reduced load, a load that the Company didn't have to serve! If the hydro is dedicated to us under the PCAM, shouldn't we get a credit for the hydro that we did not use, or shouldn't our reduced load be reflected in our having to pay less for the remaining resources? The PCAM gives us relief in neither way.

C. The PCAM Could Lead To Monthly Rate Changes

The Company offers PacifiCorp Exhibit 204 as an example of how the PCAM would work if applied to fiscal year 2004. According to the Exhibit, Oregon's adjustment for the year would be $42 million, but this does not represent how the PCAM is actually designed. The PCAM actually works on a monthly basis, not an annual basis.

According to PacifiCorp's Application the PCAM accruals will be determined monthly:

[22] Calculations based on PacifiCorp's response to CUB data request 4.

> Oregon net power cost accruals will be determined on a monthly basis and posted to a balancing account. An entry into the accrual account will occur in every month, unless the actual adjusted net power cost is identical to the level in rates.

UE 173 - PPL/Application/4.

Once the accrual reaches $15 million, PacifiCorp is “required” to request recovery and the recovery will be designed to collect these costs over a one-year period of time. But the accrual will change again with the update the following month. It might increase it more, which means that the amount being charged customers will have to increase, since the goal is to collect all costs within one year. The Company’s proposed RVM leads to rate volatility on an annual basis. This proposed mechanism seems to lead to rate volatility on a monthly basis.

This also creates problems because some months power costs will be greater than projected and in some months they will be less than projected. The amount accrued may reach the $15 million trigger in a couple of months, requiring the Company to file for collection, but it may then decline to zero or a negative number in the next couple of months.

This also creates problems with the sharing bands. Once the variance Company-wide (not just in Oregon) reaches $100,000 on an annual basis, the sharing shifts from 70/30 to 90/10. We could reach this threshold in the middle of the year, so that costs start accruing to Oregon customers with 90% being allocated to customers, and then fall back below the $100,000 before the end of the year. Does the Company keep this difference? Do we true-up the account at the end of the year?

D. The PCAM Should Allocate Costs to the State That Causes The Cost

We have already raised concerns about the use of forecasted allocation factors to allocate actual costs, but the use of allocation factors includes additional complications. As we have described, the allocation factors used in a PCA should be based on actual conditions, not forecasted conditions. However, if the Company were to use allocation factors based on actual conditions, and calculate Oregon accruals on a monthly basis, the Company could not know the actual annual load that would be required to calculate the actual annual allocation factors, because the actual annual load had not yet happened.

As a matter of policy, this is not a bad thing, because the use of monthly allocation factors, instead of annual allocation factors, would better match power costs to the state that caused the costs. There has been a great deal of concern in recent years that Oregon ratepayers are subsidizing the cost of Utah's large, and growing, summer peak. The Revised Protocol uses Seasonal Allocation Factors for some resources as a way to reduce these seasonal subsidies, but this can only address subsidies created by normalized summer peaks.

A potentially bigger subsidy problem is caused by the actual summer peaks. CUB Exhibit 107[23] shows that Utah Power's summer peak this year was 20% higher than was forecast. PacifiCorp's proposed PCAM would allocate the costs associated with this summer spike based on the forecasted annual load of each state, completely disregarding which state caused this far-greater-than-forecast summer peak. A much better matching of costs to those customers who create the costs would result from allocating power costs based on the states' loads in the month the costs were incurred. By doing this, the high

[23] PacifiCorp press release about Utah's peak load on July 12, 2005.

summer peak costs would be more accurately allocated to the state that caused the summer peak.

Though this detail may seem minute in the context of the major problems with the Company's proposed PCAM, it does serve to demonstrate the complexities of the proposed mechanism, and how unintended consequences are easily lost in such convoluted mechanisms. The relative simplicity of CUB's proposal serves both to maintain the traditional risk and reward balance that Oregon ratemaking has been based upon, as well as provide a relatively transparent mechanism, the results of which are less likely to surprise us.

E. Excluding QFs From Sharing Bands Is Bad Policy

The Company proposes two sharing bands for variations in net power costs, but exempts Qualifying Facilities (QFs) from the sharing bands. The only explanation they offer for this is: "because the purchases are required by PURPA."[24]

PURPA has been around for decades and the Company has traditionally absorbed 100% of the costs associated with new QFs between general rate cases. Now the Company wants to shift 100% of this cost onto customers. This makes little sense. Why is the Commission expected to suddenly change its approach in response to a law that was passed nearly 30 years ago? That is quite a regulatory lag.

The real issue isn't whether QFs are required by law, but what should good regulatory policy be towards QFs. It is the Company who negotiates the QF contracts on behalf of the system. Good regulatory policy suggests that the Company should have some skin in the game. QFs, unless they are not prudent, will go into base rates in the

---

[24] PPL/200/Widmer/7.

next general rate case (or sooner, if the Commission approves the RVM). Asking the Company to absorb a limited share of the regulatory lag creates a good incentive for the Company when it negotiates the contracts.

In addition, traditional regulatory policy has the Company absorb cost increases and retain cost decreases between rate cases. The Company receives a return on equity in exchange for this. A PCA is a departure from the traditional risks of ratemaking and should only be done when the risks go beyond what the Company is being compensated for in its ROE. The Company has offered no evidence to support a claim that QFs provide such a level of risk that they should be allocated with no sharing. In fact, the Company has not even made such a claim in this docket.

The Company is required to sign a QF contract if the cost of power from that facility is priced at or below market alternatives. This creates a situation where there could be two contracts with identical terms, but because one contract is a QF, it would be treated differently and cost ratepayers more. This also makes little sense. The ratemaking treatment of two contracts with similar economic terms should be consistent.

F. The Limited Prudence Review Is Unacceptable

The Company proposes to limit the prudence review of costs in the PCAM:

> 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.

PPL/200/Widmer/10.

CUB will not agree to this. CUB does not review every contract and every resource for prudence in every proceeding. When we believe it is appropriate to do so, we file evidence with the Commission demonstrating imprudence by a utility, and we expect that the Commission will review the evidence and fairly consider it. If we do not challenge the prudence of a contract or resource, we are not stating that the contract is prudent, and we are not waiving our right to challenge that contract's prudence in a future proceeding.

This provision, when combined with the Company's proposed RVM creates a Catch-22 for customers. In the RVM some contracts are added as updates after the Commission has rendered its decision in the case. This means that we cannot challenge the prudence of those contracts before they are added to rates. The proposed PCAM now says that, once these contracts are added to rates, their prudence cannot be challenged. If we don't have the opportunity to challenge them before they are added to rates, and we are prohibited from challenging them after they are in rates, then there is no prudence review.

Finally, it needs to be noted that the full implications of a particular contract may not be visible in the test year associated with a rate case. If a contract comes in during the last month of a test year, it might not have much impact or get much scrutiny, but later, when the full implications of that contract are known, we may find it to be imprudent. In addition, a contract could have a price escalator that is not visible the first year, but leads to imprudent prices later.

Prudence reviews are a fundamental part of the regulatory system. CUB will not agree to a limitation on them.

V. CUB's Proposed PCA

We have had a slew of PCA and deferral filings in recent years. CUB has generally opposed the utilities' proposals as wildly biased toward the companies, and has urged the Commission to reject those proposals. We are growing tired of this exercise. We no longer expect the utilities to produce what we consider to be a reasonable proposal, and don't see that this lengthy process of dockets has resolved anything. Rejection of proposed mechanisms has not led utilities to propose mechanisms that respond to the concerns or analysis of CUB, Staff, and ICNU.

It is time to change this dynamic; rather than asking the Commission to reject the Company proposal and providing principles or alternatives that could be considered in an appropriate mechanism, CUB believes it is time for the Commission to adopt an acceptable mechanism. An acceptable mechanism is one that responds to extraordinary events, such as severe hydro conditions or significant and ill-timed plant outages, for which the Commission would allow cost-recovery in a deferral. We can think of this as an extreme events PCA or we can think of this as establishing the rules for power cost deferrals before events occur.

The last power cost deferral the Commission approved for PacifiCorp was UM 995. While CUB was not happy with the outcome of the prudence review phase of that docket, we believe that the underlying mechanism was fair. This is the starting point for our PCA proposal. In UM 995, the Commission established a deadband of 250 basis points of return on equity. In the case of a PCA, we continue to believe that a deadband should be asymmetrical, since the risk of power costs variance is asymmetrical – higher costs leading to surcharges will happen more frequently than lower costs leading to credits. Therefore, we recommend a deadband of 250 basis points when power costs are above those in rates, and 125 basis points when they are below.

The Commission should establish a 50/50 sharing band for costs that are 150 basis points outside of the deadband. For the same reason as described above regarding the deadband, the sharing bands should be asymmetrical, so the 50/50 sharing band would be from 250 basis points to 400 when power costs are high, and from 125 to 200 basis points when they are low. In keeping with the UM 995 deferral, the Commission should establish a final 75/25 sharing band for costs outside the 50/50 sharing band; i.e., costs above 400 basis points and costs below 200 basis points.

It should be noted that this mechanism was in place during the Western Power Crisis. During that time, in addition to the reductions in Company revenues due to the sharing bands, the Company had an additional reduction of 18% due to the prudence review. Even with these disallowances, Standard & Poor's said the Commission's decision represents "support for credit stability at the utility."[25] CUB Exhibit 111.[26] This suggests that a PCA with similar terms would be viewed positively by credit rating agencies.

Unlike PacifiCorp's PCAM mechanism which is complex and flawed, CUB recommends that the mechanism be kept simple. The deadband and sharing bands are designed to protect customers from unintended consequences. This means we do not have to worry about allocating different costs to different allocation factors and such. Instead we simply propose that, at the end of each year, the Company file a report that compares actual power costs to baseline power costs. The costs would be allocated to each state

[25] UE 170 - CUB/103/Jenks/6.
[26] Standard & Poor's report.

based on the state's share of actual load for the month that the cost was incurred. The baseline would come from the RVM if there is an RVM, or from the most recent rate case in the absence of an RVM. Costs would be reviewed for prudence, and the Commission would determine the appropriate amortization period.

CUB Proposal

Baseline	Result of most recent rate case or most recent RVM
Deadband	125 basis points below baseline & 250 basis points above baseline
50/50 Sharing	Between 125 and 200 basis points below baseline & Between 250 and 400 basis points above baseline
75/25 Sharing	Below 200 basis points below baseline & Above 400 basis points above baseline
Allocation	Based on Oregon's actual share of monthly load
Amortization Period	Determined by the Commission

WITNESS QUALIFICATION STATEMENT

NAME: Bob Jenks

EMPLOYER: Citizens' Utility Board of Oregon

TITLE: Executive Director

ADDRESS: 610 SW Broadway, Suite 308
Portland, OR 97205

EDUCATION: Bachelor of Science, Economics
Willamette University, Salem, OR

PREVIOUS EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UG 152, UM 995, UM 1050, UM 1071, UM 1147, and UM 1121. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America

PacifiCorp	**Oregon CY06 (Mean) (10.06.04) 12 mc**
Oregon GRC CY2006	Net Power Cost Analys
Period Ending December 2006	**01/06-12/06**
	(MWh)
NET SYSTEM LOAD	56,050,898
SPECIAL SALES FOR RESALE	
AEPCO	-
Black Hills	364,784
Blanding	13,140
BPA Flathead Sale	353,808
BPA Wind	46,479
CDWR	-
Cowlitz	-
Flathead	104,832
Hurricane Sale	10,496
LADWP (IPP Layoff)	539,064
PSCO	1,156,461
SCE	736,000
Sierra Pac 2	459,900
SMUD	350,400
UMPA	-
UMPA II	223,614
WAPA I	-
Short Term Firm Sales	5,057,350
System Balancing Sales	5,075,546
TOTAL SPECIAL SALES	14,491,874
TOTAL REQUIREMENTS	70,542,772
PURCHASED POWER & NET INTERCHANGE	
APS p167566	97,600
APS p172318	48,800
APS p205692	82,400
APS Supplemental Purchase	409,000
Aquila hydro hedge	-
Avista Summer Capacity	-
Clark S&I Agreement (Net)	687,704
Combine Hills	126,424
Constellation Purchase	-
Deseret Purchase	814,680
Desert Power	-
Douglas PUD Settlement	78,072
Duke HLH	244,800
Duke p99206	244,800
Gemstate	48,840
Georgia-Pacific Camas	219,851
Grant County	87,668
Hermiston Purchase	1,852,964
Hurricane Purchase	1,047
Idaho Power RTSA return	(97,612)
IPP Purchase	539,064
J Aron temperature hedge	-
Kennecott Generation Incentive	-
Magcorp	-
Morgan Stanley call	-
Morgan Stanley p189046	-
Morgan Stanley p189047	-
Morgan Stanley p196538	123,200
Morgan Stanley p206006	41,600
Morgan Stanley p206008	-
NuCor	-
P4 Production	-
PGE Cove	12,000
Pinnacle West	-
PowerEx p181986	-
Public Service NM	-
Rock River	161,800
Sempra call	-
SF Phosphates	-
Small Purchases east	7,505
Small Purchases west	-
TransAlta Purchase	3,425,664
Tri-State Purchase	227,758
UBS Summer Purchase	30,800
QF California	36,229
QF Idaho	76,768
QF Oregon	109,703
QF Utah	3,495
QF Washington	13,978
QF Wyoming	11,644
Biomass	175,000
Desert Power	460,224
D.R. Johnson	66,430
Kennecott	192,720

PacifiCorp	**Oregon CY06 (Mean) (10.06.04) 12 mo**
Oregon GRC CY2006	Net Power Cost Analysi
Period Ending December 2006	**01/06-12/06**
	(MWh)
Sunnyside	385,060
Tesorro	48,960
US Magnesium	235,224
Canadian Entitlement	(84,864)
Chelan - Rocky Reach	286,588
Douglas - Wells	252,319
Grant - Priest Rapids	-
Grant - Wanapum	750,667
Grant Displacement	405,696
Grant Reasonable	-
Grant Surplus & Additional	102,551
APGI/Colockum Capacity Exchange	(269,019)
APS Exchange	850
Avista Seasonal Exch	-
Black Hills CTs	-
BPA Exchange	(1,695)
BPA FC II Storage Agreement	320
BPA FC IV Storage Agreement	2,994
BPA Peak Purchase	(4,025)
BPA So. Idaho Exchange	37,269
Cowlitz Swift	(24,230)
EWEB FC I Storage Agreement	1,544
LDWP Exchange 148830	-
PSCO FC III Storage Agreement	277
Redding Exchange	(121)
SCL State Line Storage Agreement	21,169
Tri-State Exchange	(900)
Short Term Firm Purchases	1,277,900
System Balancing Purchases	3,248,011

TOTAL PURCHASED PW & NET INT.	17,335,165
COAL GENERATION	
Carbon	1,235,932
Cholla	2,656,774
Colstrip	1,043,468
Craig	1,216,742
Dave Johnston	5,775,800
Hayden	602,051
Hunter	8,428,802
Huntington	6,680,379
Jim Bridger	10,351,438
Naughton	4,856,578
Wyodak	2,230,291

TOTAL COAL GENERATION	45,078,256
GAS GENERATION	
Currant Creek	316,754
Gadsby	138,439
Gadsby CTs	80,840
Hermiston	1,852,964
Little Mountain	81,126
West Valley CT	569,426

TOTAL Gas FIRED GENERATION	3,039,548
HYDRO GENERATION	
West Hydro	4,208,078
East Hydro	580,593

TOTAL SYSTEM HYDRO	4,788,671
OTHER GENERATION	
Blundell	179,409
Foote Creek I	121,723

TOTAL OTHER	301,132
	================
TOTAL RESOURCES	70,542,773
	================

Washington Deadbands
As A Percent of Gross Operating Revenue

Company	Gross Operating Revenue (million $)	Deadband (million $)	% of Revenue
PSE	$1,365.50	20	1.46%
Avista	$387.50	9	2.32%

Source: Annual Statistics of Electric Companies, 2002
Washington Utilities and Transportation Commission

UE-173/PacifiCorp
August 9, 2005
CUB Data Request 1

CUB Data Request 1

PPL/300/2 states that the primary principle for the jurisdictional allocation methodology contained in the PCAM was to ensure that it is consistent with the allocations under the Revised Protocol.

a. Did the MSP process consider or evaluate an allocation methodology that included hydro, weather, and other elements that were not normalized.

b. Please identify all studies done during the MSP process which addressed the allocation of power costs that included hydro, weather, and other elements that were not normalized.

c. Please identify all MSP meeting agendas that included discussions or presentations concerning the allocation of powers costs that are not normalized.

d. Please identify where in the Revised Protocol there is a discussion of allocation of power costs that are not normalized.

e. Please identify where in the record (testimony, briefs…) before the Oregon Commission in UM 1050 there is a discussion of allocation of power costs that are not normalized.

f. Did any of the load growth studies used in the MSP process include a PCAM? If so, please provide a copy of the study.

Response to CUB Data Request 1

a. No.

b. Please refer to the Company's response to CUB 1 a above.

c. Please refer to the Company's response to CUB 1 a above. While there was no explicit modeling of the effects of non-normalized power costs, there was an express recognition by the Oregon parties that departing from a rolled-in method and allocating a greater share of hydro resources to Oregon customers could increase price volatility to Oregon customers. Representatives of CUB and the Oregon staff regularly assured other MSP participants that this was a risk they were willing to take in order to obtain a hydro endowment.

d. The Revised Protocol does not discuss the allocation of power costs that are not normalized.

e. As far as the Company is aware, there was no discussion or record before the Oregon Commission MSP Docket UM-1050 related to the allocation of power costs that are not normalized.

f. No. Please also refer to the Company's response to CUB 1 a above.

Load 2000 - 2004
Actual as a % of Forecast

2000	OR	WA	CA	WY	UT	ID	Total
Forecast Load (MWh)	15,993,887	4,474,970	916,354	7,560,504	19,223,454	3,294,620	51,463,789
% of Total	31.1%	8.7%	1.8%	14.7%	37.4%	6.4%	100.0%
Actual Load (MWh)	15,603,612	4,540,498	925,786	7,569,068	20,459,746	3,419,259	52,517,969
% of Total	29.7%	8.6%	1.8%	14.4%	39.0%	6.5%	100.0%
Actual as a % of Forecast	98%	101%	101%	100%	106%	104%	102%

2001	OR	WA	CA	WY	UT	ID	Total
Forecast Load (MWh)	11,599,509	3,279,972	674,883	5,794,609	15,847,053	2,590,171	39,786,196
% of Total	29.2%	8.2%	1.7%	14.6%	39.8%	6.5%	100.0%
Actual Load (MWh)	15,025,360	4,413,518	865,652	8,450,550	20,259,594	3,406,870	52,421,544
% of Total	28.7%	8.4%	1.7%	16.1%	38.6%	6.5%	100.0%
Actual as a % of Forecast	130%	135%	128%	146%	128%	132%	132%

2002	OR	WA	CA	WY	UT	ID	Total
Forecast Load (MWh)	15,843,508	4,446,780	897,966	8,200,219	21,344,263	3,419,260	54,151,997
% of Total	29.3%	8.2%	1.7%	15.1%	39.4%	6.3%	100.0%
Actual Load (MWh)	14,312,835	4,384,929	911,557	8,015,955	20,369,294	3,552,418	51,546,988
% of Total	27.8%	8.5%	1.8%	15.6%	39.5%	6.9%	100.0%
Actual as a % of Forecast	90%	99%	102%	98%	95%	104%	95%

2003	OR	WA	CA	WY	UT	ID	Total
Forecast Load (MWh)	15,571,756	4,402,967	906,467	7,958,215	20,896,604	3,303,445	53,039,454
% of Total	29.4%	8.3%	1.7%	15.0%	39.4%	6.2%	100.0%
Actual Load (MWh)	14,271,717	4,469,641	892,687	8,181,860	21,126,129	3,636,800	52,578,834
% of Total	27.1%	8.5%	1.7%	15.6%	40.2%	6.9%	100.0%
Actual as a % of Forecast	92%	102%	98%	103%	101%	110%	99%

2004	OR	WA	CA	WY	UT	ID	Total
Forecast Load (MWh)	15,189,252	4,505,482	938,388	7,969,239	22,015,126	3,563,328	54,180,815
% of Total	28.0%	8.3%	1.7%	14.7%	40.6%	6.6%	100.0%
Actual Load (MWh)	14,323,864	4,526,259	963,911	8,445,649	21,484,039	3,577,589	53,321,311
% of Total	26.9%	8.5%	1.8%	15.8%	40.3%	6.7%	100.0%
Actual as a % of Forecast	94%	100%	103%	106%	98%	100%	98%

5-Year Average	OR	WA	CA	WY	UT	ID	Total
Forecast Load (MWh)	14,839,582	4,222,034	866,812	7,496,557	19,865,300	3,234,165	50,524,450
% of Total	29.4%	8.4%	1.7%	14.8%	39.3%	6.4%	100.0%
Actual Load (MWh)	14,707,478	4,466,969	911,919	8,132,616	20,739,760	3,518,587	52,477,329
% of Total	28.0%	8.5%	1.7%	15.5%	39.5%	6.7%	100.0%
Actual - Forecast (MWh)	-132,105	244,935	45,107	636,059	874,460	284,422	1,952,879
Actual as a % of Forecast	99%	106%	105%	108%	104%	109%	104%

UE-173/PacifiCorp
August 9, 2005
CUB Data Request 2

CUB Data Request 2

According to a Company news release, on July 12, 2005, Utah Power hit a new record peak demand of 5,848 MW.

a. What was the forecasted peak demand of Utah Power for July 12?

b. What was the forecasted net power cost for PacifiCorp for July 12?

c. What was the forecasted usage for PacifiCorp on July 12?

d. What was the actual usage for PacifiCorp on July 12?

e. What was the actual net power cost for PacifiCorp for July 12?

f. What was Oregon's energy usage and peak demand on July 12?

g. Under the methodology of the PCAM, what would Oregon's share of net power costs be for July 12?

h. What was the highest level of demand forecasted for a single day in 2005 for Utah Power?

Response to CUB Data Request 2

a. In December 2004, we forecast the hourly peak for Utah Power net system load on July 12, 2005 to be 4,775 MW. On July 11, 2005 we forecast the peak for Utah Power net system load for July 12 to be 4,836 MW.

b. The Company does not forecast net power cost on a daily basis.

c. The forecasted usage for July 12 was 172,955 MWH.

d. PacifiCorp's actual energy usage (net system load) for July 12, 2005 was 174,094 MWH. This number is preliminary.

e. The Company does not calculate the actual net power cost on a daily basis.

f. PacifiCorp's actual energy usage and peak demand for the state of Oregon on July 12, 2005 is not available at this time, but will be provided as soon as final information is available.

g. Please see the Company's response to part e of above.

h. Based on forecasts prepared more than one or two days ahead, the highest demand forecasted for Utah Power net system load in 2005 is 4,799 MW.

Press Release

Tue, Jul 12, 2005

Rising heat produces record demand for electricity

Utah Power customers today hit a new record peak demand for electricity at 5 p.m. with a demand of 5,848 megawatts. The previous high of 5,688 megawatts was recorded on July 22, 2003.

“We were able to meet the demand for electricity today with our existing resources and the addition of the Currant Creek power plant and the Cool Keeper load control program,” said Rich Walje, president of Utah Power. “In fact, without the Cool Keeper air conditioning program, the peak demand today would have been even higher.”

Utah Power is a participant in the state’s PowerForward program. It notes that the Utah Department of Environmental Quality has issued a PowerForward yellow alert for Wednesday, July 13.

“The company is an enthusiastic supporter of the PowerForward program and urges all electric consumers to take steps to conserve electrical energy as individual safety and comfort permit,” Walje stated. “When we all make individual efforts at conservation, it can add up to a significant impact on the electrical system in Utah.”

Walje noted that the single highest user of electricity at this time of year is the air conditioner. A recommended setting for the air conditioner is 78 degrees or higher as individual circumstances permit. In addition, Utah Power offers the Cool Keeper program to help mange the air conditioning demand on certain high-demand summer days. More information on this program is available on Utah Power’s website,www.utahpower.net , or by calling 1-800-357-9214.

Additional examples of conservation steps individual consumers can take include:

Cooling:

- Keep air conditioner filters clean.
- Don’t block window air conditioners.
- Use a programmable thermostat.
- Reduce the use of heat-producing appliances such as the oven, range, dishwasher, washing machine and dryer.
- Make sure your home has the appropriate amount of insulation in walls, attics and crawl spaces.
- Insulation is just as important in the summer as it is during the winter since it helps keep warm air outside.
- Plant deciduous trees to shade your home’s walls, windows and roof in the summer.
- Install a ceiling fan to circulate air above the area where you spend most of your time.
- Run exhaust fans when you shower or cook to vent warm air.

Refrigeration:

- Keep condenser coils clean and unobstructed for maximum energy savings.
- Set the temperature of your refrigerator between 37 and 40°F, and your freezer at 0°F for top efficiency.
- Keep your refrigerator or freezer full, but do not overload it.
- Cover all liquids stored in the refrigerator. Moisture can be drawn into the air, making the unit work harder.

Lighting:

- Place compact fluorescent bulbs in most frequently used light fixtures.
- Keep lights off in unoccupied rooms and get in the habit of turning off the light every time you leave a room for more than a few minutes.
- Install dimmers in areas where they make sense, such as the dining room and bedroom. The amount you dim equals your energy saved. For example, lights dimmed 15 percent reduces energy consumption up to 15 percent.

Cooking:

- Consider using a microwave oven, small portable electric frying pan, outdoor grill, or toaster/broiler instead of the conventional oven.
- Cook by time and temperature. Precise timing eliminates repeated opening of the oven door to check on cooking progress. Each time the door is opened, the temperature drops 25 to 50°F.
- Choose pots and pans that evenly cover the heating elements. Use pans with flat bottoms, straight sides and tight-fitting lids that hold heat and permit lower settings.
- Use a slow cooker or crockpot to cook stews and other single-dish meals.

Media inquiries:newsdesk@PacifiCorp.com .

UE-173/PacifiCorp
August 9, 2005
CUB Data Request 5

CUB Data Request 5

Why did PacifiCorp decide to use actual power costs in determining the PCAM variance, but use normalized loads for allocating that variance?

Response to CUB Data Request 5

The Company uses allocation factors based on normalized loads for allocating the variance, since these are the same allocation factors traditionally used to allocate the baseline net power costs. As shown in Attachment CUB 6 b, using allocation factors based on actual load, rather than normalized load, shows a total change in Oregon's Allocated Share of the Net Power Cost Variance of $0.6 million out of a total of $41.7 million.

UE-173/PacifiCorp
August 9, 2005
CUB Data Request 12

CUB Data Request 12

Please provide the following information consistent with Exhibit 204:

a. What is the forecasted usage associated with the Baseline Net Power Costs in MWh?

b. What is the forecasted average net power cost in $/MWh associated with the Baseline Net Power Costs?

c. What is the actual usage associated with the Actual Net Power Costs?

d. What is the actual average net power costs in $/MWh associated with the Actual Net Power Costs?

e. What is Oregon forecasted usage in MWh associated with the Baseline Net Power Costs?

f. Using the Revised Protocol what would be Oregon's forecasted average net power costs in $/MWh associated with the Baseline Net Power Costs?

g. What is Oregon actual usage associated with the Actual Net Power Costs?

h. What is Oregon's actual net power costs in $/MWh associated with the Actual Net Power Costs?

Response to CUB Data Request 12

a. 53,213,832 MWh.

b. $11.24/MWh

c. 52,893,793 MWh.

d. $14.10/MWh

e. 14,975,101 MWh

f. $13.14/MWh

g. 14,323,864 MWh.

h. $16.24/MWh

UE-173/PacifiCorp
August 9, 2005
CUB Data Request 10

CUB Data Request 10

Exhibit 204 assigns 57.78% of Western Company-Owned hydro and 69.729% of Mid-C hydro to Oregon.

a. If we take these percentages of forecasted hydro output and subtract this volume of energy from Oregon's forecasted load, what percentage is Oregon of the remaining load forecast?

b. If we take these percentages of actual hydro output and subtract this volume of energy from Oregon's actual load, what percentage is Oregon of the remaining actual load?

Response to CUB Data Request 10

a. 22.55%

b. 22.49%

BULLETIN: PacifiCorp Receives Support from Western Regulators

Kathryn Mock, San Francisco (1) 415-371-5009

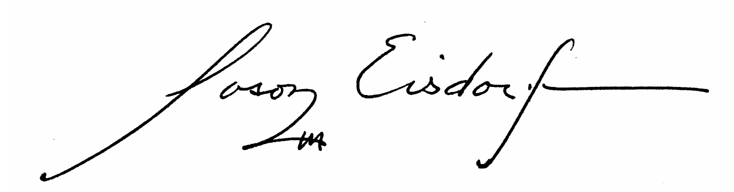
On July 18, the Oregon Public Utilities Commission approved an agreement allowing PacifiCorp (A-/Negative/A-2) to recover $137 million, or 82%, of its deferred $167 million, including carrying charges. Full recovery of the $137 million, which will require an increase in the current surcharge of 3% to 6%, should occur within three to four years. This order follows recovery orders of $147 million in Utah, $25 million in Idaho, and $7 million in California, all of which represent support for credit stability at the utility. General rate cases in Wyoming ($31 million) and California ($16 million) are still pending, in addition to the recovery of $91 million in excess power costs in Wyoming.
The outlook on PacifiCorp remains negative as a result of credit concerns at parent ScottishPower U.K. PLC, including decreasing margins in the U.K. energy supply market and uncertainty over the application of £2.05 billion ($2.96 billion) of proceeds from the sale of the U.K. water service company, Southern Water Services PLC. Continuing improvements in operating performance combined with clarification over the use of the cash proceeds from Southern Water could lead to greater stability at the current rating level.

For a complete list of ratings, please click the hyperlink provided here
http://www.rtr.standardandpoors.com/NASApp/rtr/InitialRtrServlet

CERTIFICATE OF SERVICE

I hereby certify that on this 19th day of August, 2005, I served the foregoing Opening Testimony of the Citizens' Utility Board of Oregon in docket UE 173 upon each party listed below, by email and U.S. mail, postage prepaid, and upon the Commission by email and by sending 6 copies by U.S. mail, postage prepaid, to the Commission's Salem offices.

Respectfully submitted,



____

Jason Eisdorfer #92292
Attorney for Citizens' Utility Board of Oregon

DATA REQUEST RESPONSE CRT
PACIFICORP
825 NE MULTNOMAH, SUITE 800
PORTLAND OR 97232
datarequest@pacificorp.com

MELINDA J DAVISON
DAVISON VAN CLEVE PC
333 SW TAYLOR, STE. 400
PORTLAND OR 97204
mail@dvclaw.com

RANDALL J FALKENBERG
RFI CONSULTING INC
PMB 362
8351 ROSWELL RD
ATLANTA GA 30350
consultrfi@aol.com

MAURY GALBRAITH
PUBLIC UTILITY COMMISSION
PO BOX 2148
SALEM OR 97308-2148
maury.galbraith@state.or.us

DAVID HATTON
DEPARTMENT OF JUSTICE
REGULATED UTILITY & BUSINESS
1162 COURT ST NE
SALEM OR 97301-4096
david.hatton@state.or.us

D DOUGLAS LARSON
PACIFICORP
ONE UTAH CENTER
201 SOUTH MAIN STREET, STE 2300
SALT LAKE CITY UT 84111
doug.larson@pacificorp.com

KATHERINE A MCDOWELL
STOEL RIVES LLP
900 SW FIFTH AVE STE 1600
PORTLAND OR 97204-1268
kamcdowell@stoel.com