BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

In the Matter of

PACIFICORP,

Request for a general rate increase in the company's Oregon annual revenues.

DIRECT TESTIMONY ON POWER COSTS

OF THE

CITIZENS' UTILITY BOARD OF OREGON

June 30, 2006

BEFORE THE PUBLIC UTILITY COMMISSION

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In the Matter of PACIFICORP, Request for a general rate increase in the company's Oregon annual revenues.	DIRECT TESTIMONY ON POWER COSTS OF THE CITIZENS' UTILITY BOARD OF OREGON

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

I. Introduction

This is only PacifiCorp's second annual power cost update, and the first since the transition adjustment mechanism (TAM) was established for the Company in UE 170. Muddying these waters is the concurrent full-blown general rate case proceeding which, though bearing the same docket number as the power cost update, is proceeding on a slower, more thorough track. This testimony addresses PacifiCorp's net variable power costs, and, in particular, those items that are appropriate for the Company's annual power cost update. This is necessary, unfortunately, because PacifiCorp, though only in its second annual update, has introduced modeling changes in the power cost update process – where they do not belong – and has brazenly notified the parties that the Company will be adding a significant cost increase later, when the parties cannot respond.

In addition, this testimony demonstrates both the theoretical and actual need to account for the extrinsic value of capacity resources that is not captured by the Company's GRID model. We recommend disallowance of a number of short-term firm sales that PacifiCorp made in 2004 and 2005 for power in high load hours delivered in 2007 when this was contrary to the Company's IRP analysis. Finally, as the notorious SMUD contract enters its third decade, as its peer contract has finally expired, and as the Company has had ample time to service this contract through other wholesale purchases according to the Company's own plan, we recommend that customers no longer be required to subsidize this wildly imprudent wholesale contract.

II. Déjà Vu – Inappropriate TAM Changes & Post-Order Updates

CUB has decried PGE's propensity to tinker with its power cost model in the Company's favor every year through the RVM process.[1] We have also expressed frustration that certain key factors, such as forward price curves and contracts, are updated after the Commission has issued its Order. In our testimony in UE 170, when PacifiCorp requested an annual power cost update to facilitate direct access (Transition Adjustment Mechanism, TAM), CUB argued that the system had not worked well for residential customers for whom the annual updates serve no purpose, and that residential customers should not be subject to the process. Though not exempting residential customers from this process, the Commission did acknowledge sharing our concerns "about establishing the TAM with its annual update because there is a certain amount of

[1] See CUB Testimony in UE 139 and UE 172, and the Settlement in UE 149.

one-sidedness to PacifiCorp's annual updates without concomitant adjustments by intervenors and Staff."[2]

A. Inappropriate Modeling Changes In The TAM Process

Yet here we are, in PacifiCorp's first annual update after TAM's adoption, and the Company has already proposed modeling changes – not in its rate case filing – but in the Company's TAM update in April. Step 14 of PacifiCorp's April TAM update changes how GRID calculates regulating margin, and increases power costs by $18 million. Step 15 changes how GRID calculates non-owned generation reserve requirements, and increases power costs by $7.8 million.

A utility's annual power cost update is, by design, an abbreviated schedule, and in the power cost track of UE 179 parties have only one round of testimony and one brief. Though PacifiCorp has only had one annual adjustment before this, it still could not resist the opportunity to introduce modeling changes in the comparatively-short TAM proceeding, changes that would result in millions of dollars for the Company. The Company filed a general rate case in February; that would have been the appropriate place, procedurally and substantively, to introduce these modeling changes.

A general rate case is the appropriate forum to explore the theoretical foundation of a modeling change and the results the change produces. A change to a utility's power cost model is not minor, and should not be rushed through the annual power cost update process. Such modeling changes should be processed through the more extensive rate case process, be fully vetted, and then applied to the Company's annual update the following year if deemed appropriate.

[2] UE 170 Order No. 05-1050.

In his testimony, Mark Widmer defends these modeling changes:

> The reserve requirement adjustments are not the type of adjustments that would normally be included in the TAM. They are adjustments that would normally be included in a general rate case in rebuttal testimony. The adjustments were included with the TAM update on April 1 in lieu of including them in the case later in rebuttal testimony. This was done to provide the Parties ample time to review the adjustments prior [to] filing testimony in the case.

PPL/503/Widmer/6.

Normally included in rebuttal testimony? Modeling changes should be introduced with the Company's original filing and no later. It is difficult enough for Staff and intervenors to assess changes and their ramifications in a general rate case without trying to follow a moving target. The suggestion that the Company was doing Staff and the parties a favor by introducing the modeling changes in the TAM update, as opposed to its rebuttal testimony, is disingenuous.

We recommend that the Commission clamp down on this misuse of the Company's annual power cost update, and send a clear signal to the utilities that changes beyond a simple update of contracts and forward price curves must be presented in a rate case, in the original filing. We cannot politely express our frustration with the utilities' inability to restrict the annual power cost updates to the indented scope. It has been a source of continual consternation, and has cost Staff and the parties an inordinate amount of time and resources. We thought that PacifiCorp understood this.

Utilities, by seeking out changes to their power cost models, can ensure that annual power cost updates increase their revenue requirement beyond a simple pass-through of updated prices, and the utilities have not been able to resist the urge to use the annual update process to introduce one-sided modeling changes. It started with PGE, and PacifiCorp is now following suit.

The Commission should put a stop to this, and disallow the Step 14 and Step 15 modeling changes in PacifiCorp's April TAM update, which will reduce power costs by $25.8 million total-company or approximately $7.2 million on an Oregon basis.

B. Centralia Formula Power Transmission

PacifiCorp also plans to take advantage of the opportunity provided by its annual power cost update to update transmission contracts late in the proceeding, possibly after the Commission's Order.

> The Company's Front Office transmission group is studying their options post June 2007. All the options involve a significant increase in transmission cost over that which is included in this docket. When the Company reaches a decision regarding which option to take, the Company will update the transmission cost.

PPL/503/Widmer/6.

While we have come to expect updates for new energy purchases and updates to forward curves well after our testimony, PacifiCorp is now telling us that it will have a new transmission contract that will "involve a significant increase," but it must be included in rates without any sort of prudence review, because our testimony is today and the Company has not yet reached a decision. The current contract expires June 30, 2007. If the Company expected the cost of a new contract to decrease it could simply wait until after the Commission order, but well before the expiration of the contract to sign a new one. However, the Company expects the cost to increase significantly, so the Company plans to add this cost to its TAM after Staff's and intervenors' analysis and testimony are done, but in time to include the added costs into rates.

The Company has made no effort to forecast this increase in cost other than to declare that it will be significant. Since the purpose of the TAM is to support direct access, it is important that the initial filing and updates be as accurate as possible, so buyers and sellers in the direct access marketplace can use that information to evaluate their options. Regardless, the Company did not include any estimates of the price of the new contract. PacifiCorp instead modeled the old contract price for the entire year, and noted that the Company will come in later and expect recovery of significantly higher costs. This means that a significantly higher cost will be added to customers' rates without any review by Staff, ICNU, or CUB. After this single round of testimony, we are finished with power costs.

Just because a cost is established in a contract, does not mean that the cost was prudently incurred. The Commission must make sure that the annual power cost update is not a means for a utility to pass unexamined costs through to ratepayers. We recommend that the Commission reject any significant changes in transmission costs relating to this contract. The current contract which is used in the Company's filing lasts through June 30, 2007. PacifiCorp can submit a new contract for review in next year's TAM, for costs starting January 1, 2008. Six months of regulatory lag for a significant cost is not excessive, in fact, before the implementation of the TAM and RVM annual power cost updates, it was standard practice.

The Commission should adopt the current Centralia transmission contract through 2007, just as PacifiCorp filed.

III. Extrinsic Value

PacifiCorp's GRID model fails to recognize the extrinsic value of capacity resources, such as gas-fired generation plants and capacity contracts. Customers pay the fixed cost of such resources, but these plants and contracts are often dispatched to the market when conditions vary from what was forecast, and so the value of capacity resources is not captured by GRID. Under these circumstances, the benefits go solely to shareholders.

GRID does not fully utilize capacity resources, because it is variations from forecast conditions that change the spread between gas and electric prices such that these plants and contracts become economic. Under varied conditions, the Company may dispatch its capacity resources to serve load or to make profitable market sales, but, in either case, it is the shareholders who benefit. Capacity resources both mitigate cost increases (thus protecting shareholders from power cost increases they are paid a return to absorb)[3], and produce revenues from off-system sales (thus giving extra profits to shareholders). The versatility of capacity resources, resources paid for by customers, provides significant value that is not captured by GRID.

This is demonstrated by the operation of the Company's marginal gas-fired units. CUB Exhibit 102 contains the production for the last several years from the Company's Gadsby and West Valley combustion turbines. The Gadsby combustion turbines are forecast to produce 99,349 MWh during the 2007 test year. During the years 2003-05, the Gadsby units averaged 270,062 MWh, or 2.7 times what is forecast in this docket. West Valley is forecast to produce 395,006 MWh, 28,524 MWh below its historic average of 423,530 MWh, and, it should be noted, West Valley produced 580,823 MWh in 2003.

We have also raised this issue with regard to capacity contracts included in PGE's RVM. PGE proposed that the fixed costs associated with capacity contracts should be

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[3] When power costs are materially higher than forecast, a utility may file a deferral to share some of those costs with customers.

paid by customers, even though, under normalized ratemaking, there is no benefit to customers from the contracts. Only non-normalized events dispatch these capacity contracts. Non-normalized costs and benefits are the utility's to absorb. Allowing a utility to charge customers 100% of the cost of capacity contracts and the fixed cost of generating units used significantly for capacity generation – all of which primarily serve to reduce non-normalized costs and generate sales revenue for the benefit of the Company – violates basic ratemaking principles. It is little more than customers paying the premium for insurance that protects and benefits shareholders.

There are two ways to adjust for the extrinsic value of capacity resources. The Commission could impute revenue, based on historic averages, to account for the additional revenue that the units can be expected to produce. Alternatively, the Commission could reduce the share of the fixed costs charged to ratepayers in order to represent the share of the fixed costs associated with normalized usage. CUB is not recommending a specific adjustment to account for the extrinsic value of PacifiCorp's capacity resources, as we anticipate that other parties will do so. We urge the Commission to consider those proposals.

The Commission should adopt an adjustment to account for the extrinsic value of PacifiCorp's capacity resources.

IV. Imprudent Short-Term Firm Sales

In 2004 and 2005 PacifiCorp entered into a number of power sale contracts for delivery in 2007. A large number of these contracts are for power delivered during high load hours and, of these, many are for delivery to Palo Verde in PacifiCorp's eastern service territory. Yet, PacifiCorp's 2004 IRP, filed in January 2005, shows that the

Company expected to barely be in load-resource balance for its system coincident peak in 2007, and to be in resource deficit for its eastern coincident peak in 2007.[4]

Exacerbating the risk of this short position was the IRP's analysis, which relied on the Company purchasing power through 1,200 MW of front office transactions.

> These amounts are proxy resources that represent procurement activity expected to be made on an annual, rolling, forward basis to help cover PacifiCorp's short position, and are *applied for all years* of the planning horizon…
>
> The Front Office Transaction amounts include transactions for both the West and the East. The West includes 500 MW of annual 7 x 24… As with any forward purchase, these resources will become a part of the overall portfolio for which balancing activities are routinely performed, such as selling off excess power during "shoulder" time periods.

PacifiCorp 2004 IRP, Appendix C - Base Assumptions, page 57. Emphasis added.

So, while having a tight capacity position overall and a short capacity position in its eastern territory – and these positions already relied on power purchases not unlike the sales the Company made – PacifiCorp sold power that could have shored-up its capacity position.

Beginning in the fall of 2004, concurrent with the Company's 2004 IRP process, PacifiCorp made short-term firm power sales for delivery in 2007, and most of the sales were for power in high load hours. Rather than making the purchases that were described and included in the IRP,[5] the Company sold power, did not make commensurate purchases, and created a larger short position that would have to be filled with purchases in addition to those already included in the Company's IRP analysis. Table 1 summarizes the short-term firm purchases and sales made between October 2004 and

[4] PacifiCorp 2004 IRP figures 3.3 and 3.5, pages 56 and 58.
[5] PacifiCorp 2004 IRP, page 52.

November 2005 for delivery in 2007, and CUB Exhibit 103 also breaks out the annual sales.

**Table 1: Short-Term Firm Sales and Purchases
October 2004 – November 2005**

	Number of Transactions	Volume of Transactions (MWh)
All Purchases	87	945,325
All Sales	585	6,719,400
Purchases: High Load Hours	42	476,000
Sales: High Load Hours	353	4,192,000

This shows that PacifiCorp sold power in 2004 and 2005 for delivery in high load hours in 2007. This same Company had a tight capacity position, including front office purchases, forecast for 2007, yet sold nearly nine times more power for high load hours than it purchased for that time period.

In addition, while the IRP assumed that the Company would purchase "500 MW of annual 7 x 24"[6] (7 days per week, 24 hours per day) for its western territory, the Company sold a great deal of annual 7 x 24 power and, even worse, 6 x 16 (6 days per week, 16 hours per day – only the high load hours of the day) in its western territory. Ironically, of the short-term firm sales, these sales are some of the earliest, made in October and November of 2004.

PacifiCorp has not demonstrated that these transactions were prudent. In UE 139 the Commission disallowed a portion of PGE power purchases based on the Company's lack of evidence supporting its decision in light of PGE's deviation from its planned power-purchasing strategy and buying in an illiquid market.

[6] PacifiCorp 2004 IRP, Appendix C - Base Assumptions, page 57.

> We also emphasize that PGE provides little if any supporting evidence relating to the price trend for 2003 power products or internal company analysis of that advanced market to justify its decision.

OPUC Order No. 02-772, page 13.

In this case too, PacifiCorp has failed to demonstrate the reasonableness of these sales in light of the Company's tight capacity position, the preponderance of sales as compared to purchases, and the fact that the purchases were made, in some cases, more than two years in advance. For PacifiCorp to have sold power when its own analysis indicates it should have bought, or at least held, power is at odds with the Company's IRP.

We recommend that the Commission disallow all of the high load hour sales made in 2004 and 2005 for 2007, as these are the sales that most expose customers to the market. The Commission should have PacifiCorp re-run GRID such that the model can use the Company's generation capacity to either serve customers or sell according to the forward curve. This must be done after the Commission's Order in the power cost track of UE 179, as the final forward price curve will not be available until after the Commission issues its Order.

V. Imprudent SMUD Contract

Three recent OPUC dockets have explored PacifiCorp's decision in the 1980s and 1990s to enter into a series of long-term contracts to sell power to other utilities throughout the West, while building the Company's market share.[7] These contracts cost customers hundreds of million of dollars by committing resources from rate base to an outside party, such that the resources were not available when they were needed to serve

[7] See CUB Testimony in UM 995, UE 111, and UE 116.

customers. PacifiCorp has since had to make more expensive wholesale purchases to meet its load that it would not have had to make had the Company not signed away generation from its rate base resources.

One of the most notorious of these contracts is the Sacramento Municipal Utility District (SMUD) contract. In 1987 the Company entered into a 30-year contract with SMUD, whereby SMUD paid the Company $94 million at the outset that was retained by PacifiCorp "and was not used to benefit ratepayers."[8] SMUD was then allowed to purchase power from PacifiCorp at $16.85 per MWh.

PacifiCorp's decision to commit a portion of its resources, built to serve customers, to a third party for decades is difficult to fathom. One year can bring surprising change, and a decade can easily turn an industry on its head. Given the difficulty utilities have in predicting next year's load, it is stunning for a utility to commit itself to serving a third party from rate base resources at a low, fixed price for three decades. It is more stunning still that a utility would expect its customers to bear the enormous risk of a wholesale sale contract that lasts for decades; this is not an appropriate position for a utility to put its customers in.

In the past, the Commission has dealt with this contract by following Utah's lead, and re-pricing the contract at $37/MWh. This is the price PacifiCorp agreed to charge Southern California Edison (SCE) for a long-term contract entered into around the same time as when the Company signed the SMUD contract. CUB Exhibit 104 is an excerpt from a Utah Public Service Commission Order that imputes the revenue to be included in rates for this contract.

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[8] CUB Exhibit 103, page 1 . Utah Public Service Commission Order in Docket No. 01-035-01.

However, there are two significant differences between the SMUD and SCE contracts. The first is the fixed $94 million up-front payment that was kept by the Company. The SMUD contract included this payment, but then had a lower power price than the SCE contract. By imputing the SCE price, the Utah Commission was attempting to establish what the price would have been if the up-front payment had not been part of the deal. The second, and now increasingly relevant, difference is the contract length. The SCE contract was a 20-year contract. The SMUD contract is a 30-year contract.

The revenue imputation of $37/MWh attempted to address the power price issue resulting from the up-front payment of the SMUD contract, but it does not address the exceeding imprudence of the SMUD contract length as compared to the SCE contract. If $37/MWh represents a power price imputation for a 20-year contract, it certainly isn't sufficient to hold customers harmless for the imprudence of a 30-year contract. It is not unreasonable to expect a longer-term contract to have a higher price, or at least price escalation, to account both for rising fuel prices and the value of stable prices for 30 years. Therefore, $37/MWh is no longer sufficient to hold customers harmless for the final decade of the SMUD contract which extends another 10 years beyond the end of the SCE contract.

Ultimately, the Company has <u>never</u> demonstrated the prudence of a low, fixed-price, 30-year contract, because it can't. Indeed, in this docket, PacifiCorp simply filed the SMUD contract at $37/MWh.[9] PacifiCorp pocketed $94 million, and left customers with a 3-decade-long liability. CUB has long argued that the Company's long-term sales made in the 1980s and 1990s were imprudent.[10] Prudence is based on the information the

[9] UE 179 PacifiCorp Revenue Requirement, pages 5.1.5 & 5.1.7.
[10] UE 111, UE 116, and UM 995.

Company had at the time of the decision; however, much of that information has been missing. In UE 995, PacifiCorp could not even produce its Risk Management Strategy that described how the Company evaluated the risk of wholesale commitments. This is despite the fact that the strategy had been approved by the Company's Board of Directors.[11]

Fortunately, we do not have to base our decision today on the prudence of the decision that the Company made in 1987. The Company recognized that these contracts were not supportable, because they committed generating resources to a third party when those resources were needed to serve the customers who were paying for them in rate base. In PacifiCorp's 1997 IRP, RAMPP-5, the Company addressed this problem by committing to use the market to acquire the power to serve these long-term contracts: "it will more closely reflect the company's strategy of relying increasingly on the wholesale market to acquire the resources needed to meet the commitments made in long-term wholesale sales contracts."[12] Here we are, nearly ten years after the Company declared its intention to use wholesale purchases to serve these sales-for-resale contracts, but PacifiCorp continues to maintain that customers should bear this burden. Ten years is certainly enough time.

The SMUD contract should be eliminated from GRID, the power dedicated to servicing that contract can then be re-dispatched to serve customers, and the Company can service its SMUD contract, according to its plans, by acquiring power in the wholesale market.

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[11] One astute observer referred to this as "the dog ate my risk management policy defense."
[12] PacifiCorp RAMPP-5, December 1997, page 3.

VI. Conclusion

We recommend the Commission modify PacifiCorp's power cost forecast for the Company's annual update as follows:

- Disallow the Step 14 and Step 15 modeling changes in PacifiCorp's April TAM update, which will reduce power costs by $25.8 million total-company or approximately $7.2 million on an Oregon basis;
- Adopt the current Centralia transmission contract through 2007, just as PacifiCorp originally filed it;
- Adopt an adjustment to account for the extrinsic value of PacifiCorp's capacity resources;
- Disallow the high load hour short-term firm sales made in 2004 and 2005 for delivery in 2007; and
- Disallow the 1987 SMUD contract.

WITNESS QUALIFICATION STATEMENT

NAME:	Bob Jenks
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ADDRESS:	610 SW Broadway, Suite 308 Portland, OR 97205
EDUCATION:	Bachelor of Science, Economics Willamette University, Salem, OR
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, UE 172, UE 173, UG 152, UM 995, UM 1050, UM 1071, UM 1147, UM 1121, UM 1206, and UM 1209. 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 Gas-Fired Generation (MWh)

	As Filed In UE 179	2005	2004	2003	2002	Average Actual
Gadsby	159,691	32,595	66,586	158,301	655,259	228,185
Gadsby CTs	99,349	166,168	258,948	385,069		270,062
Little Mountain	89,298	94,667	91,964	86,661	80,803	88,524
West Valley	395,006	343,889	395,480	580,823	373,926	423,530
Total	743,344	637,319	812,978	1,210,854	1,109,988	1,010,300

Source: ICNU Data Request 1.32 and PacifiCorp UE 179 Revenue Requirement NPC 5.1.8.
Hermiston is omitted as it is primarily a base load resource.

PacifiCorp Short-Term Firm Transactions

	Transactions No.	Transactions MWh
All Purchases	87	945,325
All Sales	585	6,719,400
Purchases: High Load Hours	42	476,000
Sales: High Load Hours	353	4,192,000
Sales: Annual	173	2,697,600
Sales: Annual 6 X 16	108	1,105,200
Sales: Annual 7 X 24	24	438,000

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of PacifiCorp for an Increase in its Rates and Charges	)))	DOCKET NO. 01-035-01 REPORT AND ORDER

ISSUED: September 10, 2001

- Begin Excerpt -

- Long-Term Firm Sales Contracts; Imputation of Revenues
    - Sacramento Municipal Utilities District (SMUD) Contract

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

In the present Docket, the Company does not dispute imputation, but argues for continued use of the $37 rate from the renegotiated SCE contract as a fair basis. The Division and the Committee argue the rate used should correspond to test-year circumstances. Given SCE contract terms, that rate is $47.70. Other parties support revenue imputation; no party opposes it.

As in Docket 99-035-10, we find that revenue imputation to the SMUD contract is warranted in this case. We consider whether its basis should be $37 or $47.70.

PacifiCorp argues the Commission's use of $37 in the previous case does not suggest an intent to impute revenues based on the actual SCE contract price during the test year. Renegotiation of this contract, states the Company, occurred in 1995, and the rate for the first year following that is $37, the amount used by the Commission. PacifiCorp informs us that power cost data in Docket No. 99-035-10 contains a test-year SCE contract price of $49.42, which, it alleges, should have been used if the intention was to base imputation on a test-year contract price.

We seek a reasonable basis for imputation, once we decide an imputation must be made. In the previous Docket, $37 was such an amount, because it was the most current contract price debated on the record and it recognized structural changes in the wholesale market. No party advocated the test year figure of $49.42 the Company now calls to our attention. In fact, no party mentioned the figure in that Docket and we were not aware of it.

The Company further argues that because certain SCE contract terms call for a price in 2001 much higher than the test year $47.70, the contract should no longer be considered a relevant benchmark for revenue imputation. Parties advocating imputation do so on the basis of the SCE contract. Even the Company supports the $37 renegotiated SCE contract price for this Docket. We therefore believe arguments opposing further use of the SCE contract are appropriately a subject for the next general rate case in which SMUD revenue imputation arises.

Issues parties enumerate that distinguish the SMUD contract from the other contracts to which we impute revenue in this Docket include an initial payment of $94 million. We concur that these factors separate the SMUD contract from other contracts and can be considered in making the imputation. In PacifiCorp's last general rate case we used the SCE renegotiated contract to impute revenues to reflect changes in the wholesale market that affected a contract similar to SMUD's that was executed at about the same time. We also sought to use data closest to the test year in that case which is one of the reasons we used the renegotiated price of $37.

In this Docket we learned that the actual test year SCE contract price in Docket No. 99-035- 01 was $49.42. The $37 price, therefore, was not the closest figure to the test year in that case though it was more reflective of the changes that had occurred in the wholesale market than the terms of the SMUD contract. We also discovered that the SCE contract is indexed to the Southern California border price of gas, a fact that could lead to unintended results not fully explored on this record. Our objective is to impute revenues to the SMUD contract to make it compensatory. The only proposals before us are to apply $37 or $47.70 to the SMUD contract. After the testimony and argument in this case, there are enough questions about the SCE contract as an appropriate reference that we will not depart from our previous decision by increasing the imputation to $47.70. Consequently, we accept the $37 per MWh figure and await further argument in a future case.

- End Excerpt -

CERTIFICATE OF SERVICE

I hereby certify that on this 30th day of June, 2006, I served the foregoing Direct Testimony on Power Costs of the Citizens' Utility Board of Oregon in docket UE 179 upon each party listed below, by email and, where paper service is not waived, by 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,

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W=Waive Paper service, Q=Confidential

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