BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 170

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

CONFIDENTIAL MATERIAL REMOVED AND SHADED IN BLACK

MAY 9, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350.

Q. PLEASE STATE YOUR OCCUPATION, EMPLOYMENT AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am a utility regulatory consultant, and President of RFI Consulting, Inc. ("RFI"). RFI provides consulting services related to electric utility system planning, energy cost recovery issues, revenue requirement, cost of service, and rate design. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in Exhibit ICNU/101.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. My testimony addresses a limited set of issues related to PacifiCorp's Generation and Regulation Initiatives Decision Tool ("GRID") model study of normalized net power costs for the projected test period, calendar year 2006. These issues were specifically reserved in the Partial Stipulation entered into by the parties to this case. I also address PacifiCorp's computation of Oregon revenue requirements under the Commission approved Revised Protocol methodology and PacifiCorp's proposed transition adjustment and Resource Valuation Mechanism ("RVM").

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have included Table 1 at the end of my summary, which illustrates my recommended test year net power cost and other revenue requirements adjustments. My major findings and recommendations are as follows:

MSP Issues

1. The Commission approved Revised Protocol requires situs allocation of "Existing QF Contract" costs in excess of embedded cost. Existing QF Contracts are those in effect prior to the effective date of the Revised Protocol. The Revised Protocol document indicates the effective date for a state is the date of Commission approval. For Oregon the effective date was January 12, 2005. Four QF contracts (Desert Power, US Magnesium, Kennecott and Tesoro) were negotiated and executed prior to that date. For these contracts expenses in excess of embedded costs should be allocated situs, rather than on a system basis. Correcting this problem results in a reduction to Oregon revenue requirements in the amount shown on Table 1.

2. The Commission approved Revised Protocol also requires PacifiCorp to acquire resources on a least cost basis and to reflect new plants in rates consistent with the laws and regulations of Oregon. The Company has failed to do so in this case.

3. West Valley was an imprudent resource selection from the very start. The Company failed to make a prudent effort to take advantage of the West Valley lease early termination clause. RFP 2003-A provided the best opportunity to obtain a lower cost replacement for West Valley. However, the Company only exercised the early termination option in May 2004 *after* pressure from regulators and ratepayer representatives. Consequently, the Company missed the best opportunity to replace the West Valley lease. Further, the RFP 2004-X solicitation for a West Valley replacement was biased in favor of continuing the lease. As a result, I include an imprudence disallowance in the West Valley adjustment shown on Table 1.

4. PacifiCorp obtained a $7.5 million concession from General Electric ("GE") when it negotiated the Gadsby combustion turbine purchase. This credit was realized as a waiver of combustion turbine rental fees, but not as a reduction to the cost of the project. By structuring the credit in this manner, the Company retained the benefit for shareholders instead of customers. I recommend a rate base offset in this amount because the Company had a conflict of interest in its negotiation for this concession and customers are entitled to the credit for this high cost resource. This adjustment is shown on Table 1.

5. Based on the requirements of OAR § 860-038-0080(1)(b), Currant Creek must be included in rates at market value, not at cost. This adjustment reduces net power costs by the amount shown on Table 1.

6. OAR 860-038-0080(1)(b) also requires that, if Gadsby and West Valley are included in rates, they should be included at market prices rather than cost. Table 1 includes an additional disallowance for Gadsby and West Valley to reflect the market price rule.

<u>Net Power Cost Issues</u>

1. I recommend a number of power cost adjustments, resulting in a reduction to Oregon's allocated net power costs. Table 1 shows the dollar impact of each of my proposed adjustments and the approximate Oregon allocation.

2. The Company has failed to recognize all of the cost offsets in the Georgia-Pacific Camus contract. Correcting this problem reduces power costs by the amount shown in Table 1.

3. PacifiCorp claims to have reversed the Hunter outage from its net power costs study. Removing this event from outage rates is appropriate because ratepayers are paying for the cost of the Hunter outage via the deferral approved in UM 995. However, Hunter was only one of many outages that occurred during the deferral period, which customers are already paying for. To eliminate all double recovery, all outages that occurred during the deferral period should be reversed from GRID, resulting in a reduction to net power costs by the amount shown on Table 1.

4. I recommend the Commission reverse the outage rate adjustments proposed by the Company (in Mr. Widmer's February supplemental testimony) related to ramping and deferred maintenance. These adjustments are not well supported, and result in an understatement of coal-fired generation. Reversing these adjustments reduces net power costs by the amount shown on Table 1.

5. The proposed station service adjustment should also be rejected. This adjustment is unnecessary and unrealistic. Reversing this adjustment reduces power costs by the amount shown on Table 1.

6. I recommend against use of the 2005 Scheduled outages in GRID in the March GRID update. This change was not made in a timely manner, and it runs contrary to existing Commission precedent. This adjustment reduces net power costs by the amount shown on Table 1.

7. I likewise recommend against the selective March update of GRID outage rates and heat rates. This adjustment reduces net power costs by the amount shown in Table 1.

RVM Issues

1. I recommend rejection of PacifiCorp's proposed Resource Valuation Mechanism ("RVM") and transition adjustment. The transition adjustment should only be changed during general rate cases. Having an annual update to net power costs will result in additional regulatory burdens and will unreasonably shift risks from the Company to ratepayers. A RVM is not necessary to provide a reasonable transition adjustment.

2. PacifiCorp's original transition adjustment was a "market-minus" proposal that would make it impossible for any customer to benefit by switching to direct access. The revised methodology referenced in the Partial Stipulation is an improvement, but the Company needs to demonstrate that it is not still a "market minus" approach. I propose a "market-plus" method based on the standard product prices to better reflect the value of freed up resources based on appropriate planning assumptions, consistent with the Commission's goals as articulated in its final Order in Docket No. UM 1081.

Table 1
Summary of Recommended Adjustments
$1,000

	Total Company	Est. Oregon Jurisdiction
		SE 27.3%
Reference:		SG 28.0%
MSP Issues	-$22,874,512	-$13,156,832
1 US Mag, Desert, Kennecott, Tesoro Si	$0	-$7,669,448
Prudence		
1 West Valley Lease	-$6,182,746	-$1,729,809
2 Gadsby CT Rate Base	-$983,630	-$246,795
OAR § 860-038-0080(1)(b)		
1 Current Creek	-$6,038,839	-$1,263,331
2 West Valley	-$4,242,698	-$885,900
3 Gadsby CT	-$5,426,599	-$1,361,548
II. GRID (Net Power Cost Issues)		
PacifiCorp Request - Updated	$851,946,860	$235,660,871
Partial Settlement Adjustment	-$28,921,114	-$8,000,000
Adjsuted Request	$823,042,525	$227,660,871
Remaining Issue Adjustments	-$65,407,599	-$18,068,301
4 GP Camus Contract	-$7,705,275	-$2,107,000
5 Excess Power Cost Outages	-$27,291,613	-$7,549,256
6 Reverse Outage Update Period	-$7,191,950	-$1,989,398
7 Reverse Maint Schedule	-$13,992,978	-$3,870,661
8 Reverse Ramping	-$2,400,500	-$664,013
9 Reverse Def. Maint	-$4,090,531	-$1,131,500
10 Reverse Station Svc.	-$2,734,752	-$756,472
Total Power Cost Adjustments -	-$65,407,599	-$18,068,301
Allowed - Final GRID Result	$757,634,926	$209,592,570
Total All Adjustments	-$88,282,111	-$31,225,132

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING PACIFICORP'S FILING?

A. Yes. PacifiCorp has already had several months to provide any corrections or updates to its filing. In the area of power costs the Company has already made two updates. The Company should not be permitted to make additional updates during the rebuttal phase of the case, as parties will not have sufficient time to address all of the pertinent issues and information. In addition, ICNU entered into a Partial Stipulation that resolved the parties disputed issues related to power cost modeling disputes, with certain enumerated exceptions. It would be particularly inappropriate for PacifiCorp to introduce new power cost modeling issues after the parties have reached a reasonable compromise on these issues.

II. MSP ISSUES

Q. WERE ICNU'S MSP ISSUES RESOLVED IN THE PARTIAL STIPULATION?

A. No. The Partial Stipulation only resolved a specific set of limited ICNU issues that were identified in the agreement. ICNU reserved the right to raise all other issues, including issues related to the MSP. In addition, the Partial Stipulation contains language that specifically allows the parties to raise power cost related issues that relate to new resources discussed in the MSP process. This includes the Gadsby, West Valley and Currant Creek resources.

Q. HAS PACIFICORP CORRECTLY APPLIED THE REVISED PROTOCOL METHODOLOGY TO DEVELOP THE OREGON JURISDICTIONAL ALLOCTION OF POWER COSTS?

A. No. The Company has assigned several existing QF contracts purely on a system basis. However, certain costs of these contracts should be assigned on a situs basis. These contracts are the US Magnesium, Desert Power, Kennecott and Tesoro QF contracts.

Q. PLEASE EXPLAIN.

A. Under the Revised Protocol methodology, costs in excess of embedded cost for Existing QF Contracts are assigned on a situs basis in the Embedded Cost Differential ("ECD") methodology. PPL/403. In the Revised Protocol document, Existing QF Contracts are defined as follows:

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

Q. HOW DOES THE PROTOCOL DEFINE THE "EFFECITVE DATE"

A. The "effective date" is not a defined term in the Revised Protocol, and there is some possible ambiguity concerning this date.[1/] However, there are only two logical choices: the date the Revised Protocol was approved by the Oregon Commission (January 12, 2005), or the date the Revised Protocol was approved by the Idaho Commission (February 28, 2005). In either case, the effective date is later than the first delivery date or the signing dates of the contracts listed above.

Q. WHAT IS THE BASIS FOR THESE EFFECTIVE DATES?

A. Section D of the Revised Protocol document addresses the issue of the effective date:

[1/] The document does reference a "proposed effective date," that merely is a suggestion that the Protocol be applied to rate cases starting in June 2004. Because effective date is not a defined term, and subsequent language in the Protocol addresses the issue of effective date, the "proposed effective date" language is of no consequence. Further, as the document cannot be effective before its Commission approval, the proposed effective date is meaningless.

> **D. Interdependency among Commission Approvals** The Protocol has been developed by the parties as an integrated, inter-dependent, organic whole. *Therefore, final adoption of the Protocol by any of the Commissions of Oregon, Utah, Wyoming and Idaho, is expressly conditioned upon similar adoption of the Protocol by the other mentioned Commissions, without any deletion or alteration of a material term, or the addition of other material terms or conditions.* Upon any rejection of the Protocol, or any material deletion, alteration, or addition to its terms, by any one or more of the four Commissions, the Commissions who have previously conditionally adopted the Protocol shall initiate proceedings to determine whether they should reaffirm their prior adoption of the Protocol, notwithstanding the action of the other Commission or Commissions. *The Protocol shall only be in effect for a State upon final adoption by its Commission.* Absent the final adoption of the Protocol, the Company will continue to bear the risk of inconsistent allocation methods among the States. (Emphasis added)

The document clearly specifies that the Revised Protocol is only in effect for a State upon *final adoption* by its Commission. The Oregon Commission first approved the document on January 12, 2005. Thus, one could argue that was the effective date for Oregon. However, the document specifies that its *final adoption* is conditioned upon approval by the Commissions in Idaho, Oregon, Utah and Wyoming. As Idaho was the *last* of the four states to approve the Revised Protocol, it stands to reason that the final adoption date, and therefore the effective date of the document, did not occur until the date it was approved by Idaho (February 28, 2005).

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

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

US Magnesium – January 2005

Desert Power – September 2004

Tesoro – September 2004

Kennecott – October 2004

All four contracts commenced prior to the final adoption of the Revised Protocol date by the Oregon Commission.

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

A. None of these contracts' costs are assigned on a situs basis in the ECD. Rather, they are allocated on the SG factor. *See* PacifiCorp response to OPUC Staff Data request ("DR") No. 403. Because all four contracts have prices that exceed embedded costs, the excess of contract price over embedded cost should be assigned situs. Table 1 shows the reduction to Oregon revenue requirements accompanying this correction.

Q. IF THE OREGON COMMISSION ADOPTS THIS ADJUSTMENT, DOES THAT MEAN IT WOULD BE RESPONSIBLE FOR INCREASING RATES IN THE UTAH JURISDICTION?

A. That is unlikely, at least for the present. Currently Utah revenue requirements are capped by the stipulation among the various parties in that state. In the last Utah rate case (Docket No. 04-035-42) the capped revenue requirement was $9 million below that Revised Protocol revenue requirement. Thus, increases in Utah revenue requirements would not necessarily equate to an increase in Utah customers' rates.

<u>Resource Acquisition Issues</u>

Q. DOES THE PROTOCOL ADDRESS THE ISSUE OF RESOURCE ACQUISITION?

A. Yes. Paragraph XII of the Revised Protocol (Commission Regulation of Resources) requires that "PacifiCorp will plan and acquire new resources on a system-wide least cost, least risk basis. Prudently incurred investments in Resources will be reflected in rates consistent with the laws and regulations of each state."

This is a very important requirement on PacifiCorp. It requires the Company to acquire resources on a least cost basis, and prohibits the Company from including imprudent costs in rates.

Q. WHY IS THIS LANGUAGE IMPORTANT?

A. In this case PacifiCorp seeks rate recovery for costs of three new resources (West Valley, Gadsby and Currant Creek). This is the first case involving Currant Creek, and owing to settlements of prior cases, the Commission has never decided the issue of prudence for the Gadsby and West Valley CTs.[2/] Thus, this case provides the opportunity for the Commission to evaluate these resources.

Q. WAS IT THE POSITION OF OREGON PARTIES DURING THE MSP THAT THESE UNITS WERE BUILT TO SERVE EASTERN DIVISION LOAD GROWTH?

A. Yes. Oregon parties consistently argued that these resources were all required to meet eastern division load growth.

Q. DOES THE REVISED PROTOCOL CURRENTLY CONTAIN ANY PROVISION THAT WOULD ASSIGN THESE GROWTH RELATED COSTS TO THE EAST?

A. No. As a result, the only avenue available to the Commission related to the costs of these resources is the language contained in Paragraph XII, quoted above.

2/ In fact, owing to rate case settlements, the prudence of these resources has never been decided in Utah or Washington either.

Q. HOW WILL YOU PROCEED WITH THIS ISSUE?

A. I will first address the prudence of Gadsby and West Valley, then discuss rule OAR § 860-038-0080(1)(b) as related to Currant Creek,[3/] Gadsby and West Valley.

West Valley

Q. BRIEFLY DESCRIBE THE WEST VALLEY LEASE.

A. The West Valley project consists of five 40 MW LM6000 CT units. The lease is a fifteen-year contract that obligates PacifiCorp to pay Pacific Power Marketing ("PPM"), a non-regulated affiliate, approximately $15.7 million per year to obtain the output from the West Valley CTs.

Q. IS WEST VALLEY A HIGH COST RESOURCE FOR PACIFICORP?

A. Yes. The test year annual revenue requirement exceeds $100/kW year, excluding fuel.[4/] In addition to the lease payment, the Company is responsible for O&M expenses and property taxes on the facility. One can infer from the lease purchase option that the original investment cost underlying the project is $765/kW. On a $/kW basis, the West Valley lease costs more than the Gadsby CTs or recent combined cycle plant additions such as the Currant Creek or Lakeside projects.

Q. PLEASE REVIEW THE CIRCUMSTANCES SURROUNDING THE COMPANY'S DECISION TO SIGN THE WEST VALLEY LEASE.

A. The West Valley lease provides a case study as to why such transactions demand extra scrutiny by regulators. This lease is a long-term, high-cost transaction that

---

3/ I suggest the Commission focus on OAR § 860-038-0080(1)(b) issues only in this proceeding and then consider the issue of Currant Creek prudence in the first case when the combined cycle portion of the plant is complete. As the facility is not yet complete as a combined cycle unit, the time is not ripe for a full prudence investigation.

4/ Total TY revenue requirements of $20,341,972 divided by 200 MW = $101.71/kW.

PacifiCorp entered into with its affiliate, PPM. It was entered into under questionable circumstances and justified using a novel methodology.

PPM began developing the West Valley Project as a "merchant plant" during the height of the Western power crisis in January 2001. At that time, there was a shortage of combustion turbine equipment in the West, resulting in a very high cost for the turbines. However, the state of the market in early 2001 was such that even a very high cost project such as West Valley could have been quite profitable, so long as prices remained high. At the time, Federal Energy Regulatory Commission ("FERC") appeared reluctant to address the problems in the Western power market suggesting prices would remain high indefinitely. West Valley could have been a very attractive investment for PPM under those circumstances.

As project development progressed, however, the power crisis abated. Once FERC set its price cap in June 2001, the high cost power from West Valley was much less attractive and PPM was caught with the West Valley project underway, but with limited prospects for finding buyers willing to purchase such expensive power. At some point during this period, PPM suspended construction of the Project until it could secure a buyer for West Valley's output. Construction was not underway when PacifiCorp issued a Request for Proposals ("RFP") in September 2001.

By the summer of 2001, PacifiCorp decided that it needed additional capacity to serve rapidly growing peak loads in its eastern control area. To address this problem an RFP was issued in September 2001 seeking resources for the summer of 2002. West Valley was one of the resources selected in the RFP process. The lease was negotiated in early 2002, and finalized on March 5, 2002. The project became operational later that year.

Given PacifiCorp's pressing need for new capacity in summer 2002, it was not possible in late 2001 to develop a larger and more economical project than West Valley. Thus, the short lead-time available for development of the project led to PacifiCorp's perceived need to sign the West Valley lease. These circumstances parallel those surrounding the Gadsby CTs, another relatively high cost 2002 capacity addition, necessitated by the pressing need for power at the time. In both cases, eastern division load growth outstripped supply, and very high costs peaking units were the only option available on a tight time schedule.

Q. IN YOUR OPINION, WAS THE WEST VALLEY LEASE A PRUDENT RESOURCE ADDITION FOR PACIFICORP?

A. No, not when one looks at the totality of the Company's participation in the project, particularly in light of the fact that it was a transaction with an affiliated company. I have concluded it was imprudent because decisions concerning the project were driven by the affiliate relationship, not the interest of ratepayers. This is based on my analysis of the project starting from the initial decision to sign the West Valley lease, to the recent evaluation of the early termination option contained in the lease.

Q. HOW DID PACIFICORP EVALUATE ITS INITIAL DECISION TO ENTER INTO THE WEST VALLEY LEASE?

A. The Company evaluated its decision to sign the West Valley lease using the Black-Scholes methodology, which is also known as option theory.

Q. IS THIS AN ACCEPTED METHOD FOR VALUING ENERGY RESOURCES?

A. Black-Scholes modeling was originally applied to applications in securities trading for valuation of stock options. While the underlying assumptions of the method may be applicable for evaluation of financial instruments, there is no proof that they apply in the case of energy derivatives or physical energy resources. In my view, at best, Black-Scholes modeling is a novel and speculative approach for resource selection by a regulated utility.

Q. HAS THE BLACK-SCHOLES METHODOLOGY BEEN WIDELY ACCEPTED FOR SECURITIES TRADING APPLICATIONS?

A. Yes. Based on my review of the literature, it is a commonly applied technique. However, it has not always been successfully applied. The Black-Scholes equations were used extensively by the infamous hedge fund, Long Term Capital Management ("LTCM"). LTCM was the fund directed by two Nobel Laureates, Myron Scholes and Robert Merton, that threw the financial world into near calamity. Exhibit ICNU/102 is an excerpt from the transcript of a February 8, 2000 episode of Nova on the Public Broadcasting Service, which summarizes the LTCM debacle. The excerpt indicates that even with the help of two of the Nobel Laureates who are credited with developing the Black-Scholes equations, the dynamic hedging methodology used by LTCM failed to predict market movements and nearly resulted in an epic collapse of the financial system.

Q. ARE YOU SAYING THE USE OF BLACK-SCHOLES MODELING FOR RESOURCE SELECTION DECISIONS IS PER SE IMPRUDENT?

A. I'll leave that for the Commission to decide. The Commission could certainly consider disallowing the costs of resources selected by the model on the basis of imprudence. However, there is also a fundamental problem of equity in that the benefits ascribed to resources by the Black-Scholes modeling are impossible to reflect in a rate case test year. Thus, PacifiCorp is in the situation of having selected resources on the basis of certain speculative benefits that will never be reflected in a rate case setting. The Company ultimately justified its decision to enter into the West Valley lease not on the basis of its fundamental economic value, but rather on the basis of this novel methodology. This approach was quite different from the analytical methods used by the Company (and accepted by regulators) in the Gadsby CT and Currant Creek certification proceedings.

Q. EXPLAIN YOUR COMMENT THAT THE WEST VALLEY LEASE IS NOT JUSTIFIED ON THE BASIS OF ITS FUNDAMENTAL ECONOMIC VALUE, BUT RATHER DEPENDS ON THE METHOD USED BY THE COMPANY TO EVALUATE THE PROJECT.

A. This is demonstrated in Confidential Exhibit ICNU/103C taken from the Company's supplemental testimony in UE 134. This document is a copy of the economic evaluation of West Valley used by the Company to support the decision to enter into the lease.[5/] Analysis of this document demonstrates that the decision to sign the lease was imprudent.

With reference to the rebuttal testimony of Mr. Mark Klein in UE 134, Confidential Exhibit ICNU/103C demonstrates that the value of the lease option was [redacted] million per year over its fifteen-year term. Because this exceeded

[5/] The Company previously contended that this analysis was the basis for its evaluation of the West Valley project in Docket No. UE 134. That case was ultimately settled as part of the global settlement in UE 147, but parties are free to continue to raise the issue of West Valley prudence. As of this date, the Commission has never directly decided the issue of prudence of the West Valley lease.

the (then expected) cost of the lease ($14.71 million), Mr. Klein contended that signing the lease was beneficial to customers and by implication prudent.

Q. BASED ON THE ANALYSIS SHOWN IN EXHIBIT ICNU/103C, DO YOU AGREE WITH PACIFICORP'S CONCLUSIONS?

A. No. The claimed net benefit margin of about [redacted]. At best, the analysis demonstrates [redacted] for the project, but only if *all* of the underlying assumptions are proven out.

However, I believe there are substantial problems with the analysis. First, the Black-Scholes method selected by the Company is responsible for a majority of the assumed benefits. Given that this method was not even applied in the contemporaneous Gadsby certification proceeding, this is quite disturbing.

Instead of applying a conventional power system simulation, PacifiCorp applied options theory (the Black-Scholes techniques) to estimate the value of the physical assets underlying the lease.

Second, the Black-Scholes method used by the Company did not provide a detailed *simulation* of the impact of the West Valley project on the PacifiCorp system, such as might be derived from a model like GRID. Indeed, the methodology really does not even consider whether PacifiCorp actually needs the power, or might even ever dispatch it for purposes of serving native load. Rather, the unit is dispatched in response to general market prices. The limited dispatch modeling shown in Exhibit ICNU/103C completely ignores factors that impact the PacifiCorp system dispatch such as minimum run rates or transmission constraints. In fact, there is very little in Exhibit ICNU/103C that would make it specifically applicable to PacifiCorp's system. It is little more than a generic analysis of the project based on expected market conditions in the Desert Southwest ("DSW") market. While this might be the norm for evaluating a merchant project for purposes of energy trading, it is not typical of the kinds of analyses performed in the industry to evaluate the economics of a capacity addition to a utility system. Clearly, this was not an example of planning on a system-wide least cost basis as required by Paragraph XII of the Revised Protocol.

Q. CAN YOU DECOMPOSE THE CLAIMED [redacted] IN ANNUAL BENEFITS FROM WEST VALLEY INTO DIFFERENT CATEGORIES?

A. Yes. The project can be thought of as producing the following benefits, based on PacifiCorp's analysis shown in Confidential Exhibit ICNU/103C:

(a) 200 MW firm on-peak capacity and energy based on its expected market value, less operating costs ([redacted]);
(b) The "extrinsic" or "option value" of the lease associated with uncertainty related to future spark spreads ([redacted]) based on the Black-Scholes equation;
(c) Avoidance of the shoulder-sell off ([redacted]);
(d) Quick start capacity ([redacted]); and
(e) Value of the early termination and project buy-out clauses ([redacted]).

These benefits add up to [redacted] million per year, or only [redacted] million (about [redacted]) more than the (then) expected annual cost of the lease ($14.7 million).

It should first be noticed that, without any single one of the assumed benefits, the West Valley project is not economic. Moreover, a reduction of the quick start benefit [redacted], the shoulder sell-off value [redacted] or the lease option value [redacted] would eliminate any economic advantage of the project. If the "Black-Scholes" option value (item (b) above), is overstated by just [redacted], then the project is uneconomic.

Of the claimed benefits, only capacity and energy (item (a) above), the shoulder sell-off value (item (c) above), and quick start capability (item (d) above) are based on what might be called the "fundamental value" of the resource such as one would expect to find in a traditional resource evaluation. Given that by March 2002 PacifiCorp had already undertaken the certification of Gadsby CT units, it is quite questionable whether PacifiCorp required the benefits provided by additional ancillary services.

Two of the most significant benefits ascribed to the West Valley project (the option value, and the value of the purchase and early lease termination options) were also estimated using Black-Scholes modeling. Without either one of these benefits, the project would have been uneconomic.

In the Gadsby certification proceedings (which occurred around the very same time), the Company did not use Black-Scholes modeling. The same is true of the more recent Currant Creek and Lakeside certification proceedings in Utah. Thus, Black-Scholes modeling seems to have been an "ad-hoc" methodology applied only at the time when the Company was evaluating the West Valley lease.

An obvious question then is why the Company used a much different approach in evaluating West Valley than it did in its decision to certify the Gadsby CT units and other recent projects. Given the narrow economic advantage for West Valley portrayed in Exhibit ICNU/103C, and the close affiliate relationship with PPM, one might assume that the Company simply "shopped" for an evaluation method that would support the overall benefit of signing the lease.

Q. ELABORATE ON THE BLACK-SCHOLES BENEFIT SHOWN ABOVE.

A. The second benefit, the "extrinsic" or "spark spread" option value derived by the Company, reflects the benefits associated with application of the Black-Scholes equations and is related to the spread in the forward price curve; specifically, the chance that the "spark spread" could change over time. Thus, we should think of the project as having a "Black-Scholes spark spread benefit" of [redacted] million. In other words, this is the amount of the project benefit that would disappear completely if we simply used the PacifiCorp forward price curve and long-term market price forecast to determine the value of the project (as was done in the case of the Gadsby and Currant Creek projects.) This is the assumed value of the project stemming from its ability to provide protection against unexpected increases in the spread between gas and electric prices. This type of benefit cannot be reflected in GRID, and was not considered in any of the recent certification cases. However, it would most certainly be a benefit to shareholders if higher than expected spark-spreads materialized, and it would provide earnings protection.

Q. WERE THERE ADDITIONAL BENEFITS CLAIMED BY THE COMPANY CRUCIAL TO THE ECONOMIC EVALUATION OF THE PROJECT?

A. Yes. Assuming PacifiCorp's forward price curve analysis and long-term market price forecast was perfectly sound, the capacity and energy benefits produce only [redacted] million in annual benefits versus an expected $14.7 million lease expense. Stated differently, the capacity and energy benefits were only [redacted] of the annual lease payment, and the Company could have obtained equivalent power for a [redacted] West Valley. Had PacifiCorp stopped at this point, it should have never signed the West Valley lease in the first place. PacifiCorp *needed* to claim these additional benefits in order to show that the West Valley lease was economic. With only a modest reduction to any of the five claimed benefits, the project is clearly uneconomic on the basis of market fundamentals and PacifiCorp's own analysis as of the signing date of the lease.

Q. WERE OTHER ASSUMPTIONS BIASED IN FAVOR OF WEST VALLEY IN CONFIDENTIAL EXHIBIT ICNU/103C?

A. Yes. It was assumed the units would operate at their design (full load) heat rate (10,000 BTU/kWh) on an annual average basis. This would be impossible if the units were going to cycle and provide substantial operating reserves as assumed by the Company. Further, the PacifiCorp GRID modeling shows much higher heat rates for these units. Finally, the Company significantly understated the staffing and O&M costs of the facility in its estimates and ignored reserve capacity costs.

Q. EXPLAIN THE SIGNIFICANCE OF ALL THIS IN THE CONTEXT OF THE FACT THAT WEST VALLEY WAS LEASED FROM AN AFFILIATE, PACIFIC POWER MARKETING.

A. This is the very reason why regulators have traditionally been extremely concerned about transactions between affiliates. Despite any protests to the contrary about prudence, the Company cannot change the fact that its lease from an affiliated Company is one of the highest cost resources on the system. It also cannot deny that it used a much different standard and technique for evaluating the project as compared to other projects it has recently acquired.

In my view, good regulatory policy would require a careful review when dealing with affiliate transactions. Indeed, FERC has adopted a standard that requires a bidding process must be "*above suspicion*" when it results in award to an affiliate. For this reason alone, it would be wise to assign no value to highly speculative and subjective benefits, such as the options value.

Q. THE LEASE ALSO CONTAINS PURCHASE OPTIONS. DID THE PURCHASE OPTIONS HAVE ANY VALUE IN 2002?

A. The purchase options were of very little value, even in 2002. The option purchase price is based on the original cost of West Valley ($765/kW) as depreciated in 2005 ($690/kW) and 2008 ($615/kW). This substantially exceeded the cost of a new conventional combustion turbine even in 2002. Based on RAMP– 6 figures, a new CT unit could be installed for around $500/kW. Further, the market for these CTs has declined sharply in the past few years, rendering the purchase option completely worthless at the present time.

Q. WAS THE EARLY TERMINATION OPTION OF THE LEASE OF ANY VALUE?

A. The option only had value because of the high cost of West Valley. If West Valley were an economical resource, an early termination option would have been without any significant value. Given its high cost, had the Company made a good faith effort to take advantage of the early termination option, it could have provided value, but only by undoing the original mistake. However, this value only exists to the extent the Company actually terminates the lease at the end of the third or sixth year and replaces it with a lower cost resource. Unfortunately, the Company never made a prudent effort to take advantage of the third year termination option.

Q. PLEASE EXPLAIN.

A. Section 12.1 (a) of the lease states as follows:

> The Lessee may terminate the Lease Term by giving the Lessor notice in writing of such termination on or before December 1, 2006; provided, however, that (i) if such notice is given on or before June 1, 2004 and not rescinded by notice in writing on or before September 30, 2004, this Lease shall terminate effective May 31, 2005; and (ii) if such notice is given after June 1, 2004 and not rescinded by notice in writing on or before June 30, 2007, this Lease shall terminate effective May 31, 2008 . . . .

The plain language of this section of the lease provided PacifiCorp an opportunity to escape from the lease in June 2005, by giving notice prior to June 1, 2004. Because the original lease was evaluated and negotiated in the aftermath of the Western power crisis, and at a time when CT capacity was very scarce, a prudent utility would have taken a very serious look at terminating the lease and replacing it with a lower cost resource.

Q. HOW WOULD A PRUDENT UTILITY HAVE RESPONDED TO THIS EARLY TERMINATION OPTION?

A. The early termination option would have been useful as a tool to obtain lower prices from other suppliers, or as negotiating leverage with PPM. To take full advantage of the option, PacifiCorp should have given its notice well in advance of June 1, 2004, and evaluated the most economical options available at an earlier time. It would have been sensible to consider a Request for Proposal ("RFP") timed to provide replacement capacity starting on June 1, 2005, because that was the date of the first termination option.

Q. DID PACIFICORP HAVE AN OPPORTUNITY TO ISSUE SUCH AN RFP?

A. Absolutely. PacifiCorp issued RFP 2003-A on June 6, 2003. This RFP was issued in ample time to have provided a permanent replacement for West Valley by June 1, 2005. RFP 2003-A even requested 200 MWs of east-side peaking capacity, an amount identical to the capacity of West Valley. The Company could have easily requested 400 MW of east-side peaking capacity for the summer of 2005. There was simply no reason why PacifiCorp could not have used the RFP 2003-A process to seek out the most economical replacement available for West Valley.

Q. DID THE COMPANY DO SO?

A. No. It appears that the Company never even considered replacement of West Valley in connection with RFP 2003-A. Further, the Company never gave its termination notice regarding the West Valley lease until very late in May 2004. This termination notice was provided only *after* inquiries into the issue were made by ICNU and the OPUC Staff, as well as the Utah Committee of Consumer Services ("CCS") and the Utah Division of Public Utilities ("DPU") staff. Exhibit ICNU/104 is a copy of certain letters discussing this issue. My interpretation of these events is that the Company simply "drug its feet" on the matter until pressure from regulators and customer representatives forced the issue. Again, this is clear evidence of a utility more interested in supporting its affiliate than minimizing costs for its ratepayers.

Q. IS IT REASONABLE TO ASSUME THE COMPANY COULD HAVE OBTAINED A LOWER COST REPLACEMENT FOR WEST VALLEY HAD IT SOUGHT A REPLACEMENT IN RFP 2003-A?

A. Yes. In Utah Docket No. 03-035-29 (Currant Creek), the Company's bid evaluation model demonstrated that traditional peaking units were much less economic than combined cycle generators. Further, given the high cost of West Valley relative to more conventional types of CTs, it is apparent that West Valley would have been a very unattractive option for the Company. One can easily infer that a West Valley "Next Best Alternative" would have never made the short list had it been examined in RFP 2003-A. Clearly the Company failed to avail itself of the best opportunity to obtain resources at a much lower cost than West Valley.

Q. DID REGULATORS MAKE INQUIRIES REGARDING THE EARLY TERMINATION OF THE WEST VALLEY LEASE?

A. Yes. In the hearing in Utah Docket No. 03-035-14 on May 20, 2004, the Commission Chair inquired as to the status of the West Valley lease:

> CHAIRMAN CAMPBELL: Let me ask about – I guess some of that was based on testimony related to West Valley, whether that was in or out or a deferrable resource contract. I guess I'd like to ask the Company, and it's my understanding that you had a major party in Oregon ask you to give notice on June 1st related to that contract. Can you just based on the testimony of that now is on the record related to West Valley, would you please let us know what you intend to do if you've made a decision?
>
> MR. TALLMAN: Well, like most decisions we're – we're looking at it pretty closely. ***One of the things that we're looking at that we're very concerned about is that we make sure we fully understand the option language that's in the agreement as far as how we understand it versus how our counter party understands it. And one of the things -- so we're having a legal analysis done on that right now***. The obvious concern with that is if we don't see it eye to eye, that if we were to go ahead and exercise an option and then change our mind and that somehow affected our ability

> with the next option period, which, of course, is a longer term decision, but the decision now is a three-year decision, it basically affects the 2005 through 2008 timeframe, which is really the summers of 2005, six, and seven. And those review the '05, '06 summers as being pretty important, at least I do, in terms of resource needs. So I'm very -- I want to be very cautious, judicious, prudent before we make the election to issue a termination notice even if we think we might have to unwind that termination notice. So that's where we are at right now. And certainly before June 4th or June 1st we'll get that sorted out.
>
> * * *
>
> CHAIRMAN CAMPBELL: I'm trying to be as subtle as I can to send signals that the Commission is interested in that contract in that the past rate case things were stipulated. And so this is the first case before this Commission we've fully seen numbers and discussion related to that contract. Clearly, we're concerned, but we are interested and ***extra interested in contracts related with affiliate***s. ***And so maybe my expectation of the Division would audit this and other parties would take a serious look at this as far as any future rate case.***

Re PacifiCorp, UPSC Docket No. 03-035-29, Reporters Transcript of Proceedings at 55-60 (May 20, 2004) (emphasis added).

Q. PLEASE COMMENT ON MR. TALLMAN'S ANSWER TO THE UTAH COMMISSION.

A. His answer seems rather strange in light of PacifiCorp's prior testimony in UE 134 (2002) and Washington Docket No. UE-032065 (2003):

> **Q. Does the lease give PacifiCorp an option to purchase the Project or terminate the lease?**
>
> A. Yes. PacifiCorp has two options (vesting in years three and six) to either terminate the lease or purchase the Project. If PacifiCorp elects to exercise either purchase option, the fixed purchase prices ($138 million and $123 million, respectively) are estimated to be near the then-depreciated book cost for the Project at the time of the purchase. These options allow PacifiCorp to hedge against changes in market prices and load forecasts in the coming years and then decide which of three paths—continuation of the

> lease, termination of the lease or outright purchase of the Project—is the best economic choice.

Re PacifiCorp, OPUC Docket No. UE 134 (Supplemental Direct Testimony of Mark Tallman).

> **Q. What specific risks are mitigated through the additional options in the lease structure?**
>
> A. There is higher uncertainty over the value of the spark spread associated with a longer time horizon, therefore, it is prudent and valuable for PacifiCorp to make provisions to cut losses if the spark spread collapsed and to capture additional value if the spread widened. The lease termination and the plant purchase provisions in year 3 and year 6 of the lease serve this risk mitigating purpose.
>
> **Q. How were the values for termination of the lease and plant purchase determined?**
>
> A. Option theory was used to value the special contract provisions. The option to abandon the lease was valued as a put option with the strike equal to the NPV of the remaining lease payments against the underlying asset price (i.e., NPV of free cash flows for the remaining lease period).
>
> The option to purchase the plant is a call option with the strike at the net book value against the underlying asset price (i.e., NPV of free cash flows until the end of the thirty-year assumed book life plus the liquidation of remaining assets). To value this option, the Company explicitly calculated the residual value of the plant based on the best market information available. The cumulative value of the put and call options in year 3 of the lease is in excess of $28,568,000. The value of this premium is included in the annual lease payment; it is not paid up-front, but instead spread across the whole duration of the lease as an annuity discounted at 2.5 percent. Therefore, if PacifiCorp exercises the lease termination option, PPM will not receive full payment for the options it granted. The annualized contract option premium is $2,110,000.

Re PacifiCorp, OPUC Docket No. UE 134 (Supplemental Direct Testimony of Mark Klein).

> **Q. Does the lease give PacifiCorp an option to purchase the West Valley Project or terminate the lease**?
>
> A. ***Yes, the lease is very flexible. PacifiCorp has two options (vesting in years three and six) to either terminate the lease or purchase the West Valley Project.*** If PacifiCorp elects to exercise either purchase option, the fixed purchase price ($138 million or $123 million, respectively) were, at the time, estimated to be near the then-depreciated book cost for the West Valley Project at the time of the purchase. These options allow PacifiCorp to hedge against changes in market prices and load forecasts in the coming years and then decide which of three paths-continuation of the lease, termination of the lease or outright purchase of the West Valley Project-is the best economic choice.

Re PacifiCorp, Washington Utilities and Transportation Commission ("WUTC") Docket No. UE-032065, Direct Testimony of Mark Tallman, (December 2003) (emphasis added).

These passages show that the Company was very quick to point out the lease termination options to the Oregon and Washington Commissions, and even ascribed a substantial dollar value to those options in UE 134. However, when it came time to actually exercise the option, the Company determined that it suddenly needed a "legal analysis" of the lease to verify these same terms and conditions.

Q. IS THIS EVIDENCE OF IMPRUDENCE?

A. Certainly. The Company should have performed a detailed legal analysis of the lease when it was being negotiated, not two years later. They should not have required any further legal analysis in order to confirm what the lease itself plainly states in Section 12.1 and what the Company told the Oregon and Washington Commissions in 2002 and 2003. It appears the Company simply used the alleged need for a legal analysis as an excuse for failing to conduct a fair evaluation of the lease through a reasonable RFP process much earlier. In any case, were a legal analysis needed at all, there is simply no prudent reason why it could not have been performed long before May of 2004.

Q. WAS RFP 2004-X A REASONABLE AND PRUDENT EFFORT TO FIND A LOWER COST REPLACEMENT FOR WEST VALLEY?

A. No. The Company biased its selection process in favor of West Valley by soliciting only bids for resources that had similar contract terms and options as West Valley:

> This solicitation seeks resources that may replace the leased resource, as more fully described below, with a resource capable of delivering electricity to PacifiCorp's network transmission system at a location that can, utilizing firm transmission rights, deliver the electricity to a point electrically North of Camp Williams and South of Ben Lomond substations. The replacement resource must be available as of June I , 2005 for terms of: a) three (3) years, or b) three (3) years with a nine (9) year extension option to be exercised at PacifiCorp's option prior to June 30, 2007, or 3) up to twelve (12) years with a three (3) year minimum.

RFP 2004-X, at 3 (issued July 19, 2004).

By issuing the RFP so late (less than 11 months prior to the date power was needed), and insisting on a minimum three-year term, the Company virtually eliminated any realistic option for the construction of new capacity.

Q. WAS THIS REASONABLE?

A. No. In effect, the Company assigned an infinite value to the early termination option, as it refused to consider options other than those with a minimum three-year term. This is strange considering that, when the Company first evaluated the lease, it believed it had a methodology that could fairly monetize the value of the early termination option. If PacifiCorp still believed in Black-Scholes modeling, it would have ascribed some fraction of the previously determined lease option value to West Valley because there was only one remaining termination option.

Q. DO YOU DISPUTE THAT THERE IS SOME VALUE IN HAVING AN EARLY TERMINATION OPTION?

A. In theory there is, but only due to the high cost of West Valley. Further, PacifiCorp is capacity short and clearly needs long-term resources. There is little reason to expect that it will suddenly become long on capacity and avoid the need for 200 MW of capacity in 2008. Further, for the option to have any real value, it must be evaluated in a manner that is timely, reasonable and prudent. PacifiCorp failed on all three counts. Given that this is a lease with an affiliated Company, there is ample reason to be suspicious of the entire arrangement. Were this case being heard by FERC, I fail to see how it would survive FERC's "*above suspicion*" standard.

Q. REGARDING THE ACTUAL BID EVALUATION IN RFP 2004-X, DO YOU BELIEVE THAT PACIFICORP'S ANALYSIS IS SOUND?

A. I am very skeptical of PacifiCorp's bid evaluation. I have had an opportunity to review the workpapers underlying the RFP 2004-X bid evaluation on November 10, 2004, and later when it was produced in discovery in the recent Utah rate case. While my review was limited in scope, it was apparent that a substantial portion of the advantage assumed for West Valley was due to modeling of its ancillary service benefits (principally spinning reserve and quick start). My discussions with personnel from the PacifiCorp dispatch center (on the same day) and review of West Valley's generator logs calls this assumption into question. Owing to the presence of substantial resources on PacifiCorp's system that are able to provide quick start and operating reserves, West Valley is seldom needed for purposes of carrying reserves and, on average, has only had 10 MW of capacity available for spinning reserve per month in 2004.

Q. HOW DID PACIFICORP DETERMINE THE ANCILLARY SERVICES BENEFITS OF WEST VALLEY?

A. I understand this was based on a GRID run where the ancillary services characteristics of West Valley were "turned off." However, there are many issues surrounding the modeling of CTs in GRID. The model is operating the CTs in a very unrealistic manner, owing to inaccurate assumptions concerning regulation modeling.[6/] Further, PacifiCorp now has reserve capacity also available from the US Magnesium contract. Thus, these ancillary services benefits derived from GRID runs are highly questionable.

Q. HOW DO YOU PROPOSE TO DEAL WITH THE ISSUES SURROUNDING THE EARLY TERMINATION OPTION?

A. Irrespective of the prudence or imprudence of the original West Valley lease decision, the Company failed to avail itself of a reasonable opportunity to obtain the best alternatives to replace West Valley in 2005. Instead, the Company made a late half-hearted effort primarily due to the prodding of regulators and consumers groups.

Consequently, I recommend the Commission adopt a disallowance based on the cost of replacing West Valley in RFP 2003-A. There were many possible alternatives to West Valley (including comparable resources with much lower costs). However, I used the cost of the Currant Creek CT as the proxy cost for a prudent winning replacement for West Valley. This results in a revenue

---

6/ This issue was one of the matters resolved in the Partial Stipulation.

requirement reduction for the West Valley lease in the amount shown on line 1 of Table 1.

Gadsby CT

Q. ARE THERE ANY ISSUES PRUDENCE RELATED TO THE COST OF THE GADSBY COMBUSTION TURBINES?

A. Yes. The installed cost of the Gadsby CTs was exceptionally high (approximately \$667/kW). In the Gadsby Certification case (Utah Docket No. 00-035-37), the Company contended that one of the benefits of the Gadsby project was the fact that General Electric ("GE") had agreed to an early termination of a rental agreement for some temporary CTs at the Gadsby site. This resulted in a \$7.5 million savings for PacifiCorp. This benefit flowed directly through to the Company and was never reflected in rates. Had the Company obtained a simple \$7.5 million price concession on the cost of the peaking units from GE, the Gadsby rate base would be reduced. I am concerned that PacifiCorp had a conflict of interest in negotiating the purchase price of the Gadsby CTs, as it may have had to choose between a lower permanent cost for ratepayers versus a one-time \$7.5 million cost savings for PacifiCorp.

Q, DO YOU WISH TO PRESENT ANY DOCUMENTS THAT SHED LIGHT ON THIS ISSUE?

A. Yes. Confidential Exhibit ICNU/105C is a copy of a portion of a PacifiCorp exhibit (Morrison Exhibit 6) presented by the Company in the Gadsby CCN case, Utah Docket No. 00-035-37. This document is a summary of information provided to the ScottishPower Board concerning the project. There are two interesting items contained in the Board presentation:

[redacted]

[redacted]

[redacted]

Confidential Exhibit ICNU/105C.

I believe this establishes three important points. [redacted]

This is a classic case of a conflict of interest that the Commission should resolve in favor of the ratepayers. I recommend that the Commission decrease the level of the Gadsby CT plant investment by $7.5 million. The impact of this adjustment (based on PacifiCorp's requested rate of return) is shown on Table 1.

Currant Creek

Q. HOW HAS PACIFICORP TREATED CURRANT CREEK IN THIS CASE?

A. The Company has annualized the cost and operation of the Currant Creek SSCT portion of the project for the 2006 test year. It has included Currant Creek at cost in its calculation of overall revenue requirements.

Q. IS THIS TREATMENT CONSISTENT WITH OAR § 860-038-0080(1)(B)?

A. No. It is completely inconsistent. OAR § 860-038-0080(1)(b) provides:

> The Commission will not require an electric company to acquire new generating resources except as provided in ORS 757.663. Major capital improvements to existing generating resources will continue to be subject to least cost planning processes and analyses and the Oregon share of their prudently-incurred costs will be included in an electric company's Oregon revenue requirement, which for a multi-state electric company shall be consistent with Commission decisions pursuant to subsection (3)(a)(G) of this rule. *Electric companies must include new generating resources in revenue requirement at market prices, and not at cost, and such new generating resources will not be added to an electric company's rate base even if owned by the electric company [.]*

OAR § 860-038-0080(1)(b) (emphasis added).

The italicized section of the code is the part most applicable to this proceeding. This language prohibits the cost of new resources from being included in rate base. Instead, new resources must be included in revenue requirements at market prices. This rule implies that new resources should be reflected in revenue requirement at current market prices, rather than actual cost. Because Paragraph XII of the Revised Protocol requires the Company to reflect the cost of new plants in rates consistent with the laws and regulations of Oregon, this proposed treatment is not permitted under the Revised Protocol. I have included Currant Creek in rates based on the net market value of the power produced by the project as derived from the Thermal Revenue output of GRID. This adjustment reduces net power costs by the amount shown on Table 1.

Q. DOES OAR § 860-038-0080(1)(b) APPLY IN THE CASE OF GADSBY AND WEST VALLEY IN THIS CASE?

A. It is ICNU's position that OAR § 860-038-0080(1)(b) applies in the same manner for Currant Creek, Gadsby and West Valley because all three plants came on line after the application of the rule in September 2000. While the Gadsby and West Valley units arguably have been included in prior rate cases at cost not market value, those cases have settled. In addition, there is nothing in the language of OAR § 860-038-0080(1)(b) to imply it would not apply the same for Gadsby and West Valley as for Currant Creek. Further, PacifiCorp has not asked for a waiver of the rule for these units. Consequently, ICNU recommends that the Commission apply OAR § 860-038-0080(1)(b) in the same manner for all new resources: Currant Creek, Gadsby and West Valley.

Q. ASSUME THAT THE COMMISSION AGREES THAT OAR § 860-038-0080(1)(b) ALSO APPLIES TO THE GADSBY AND WEST VALLEY CT UNITS. WHAT WOULD BE THE RESULTING DISALLOWANCES?

A. OAR § 860-038-0080(1)(b) would supersede the prudence adjustments discussed earlier. In that case, I have computed a disallowance of $1,608.343 for the Gadsby CTs and $2,615,709 for West Valley. These adjustments exceed the prudence adjustments I discussed earlier. If the Commission applies the market value rule, these disallowances should be made irrespective of whether the Commission believes these new resources were prudent. In Table 1, I show the incremental amount of these adjustments over and above the prudence adjustments. If the Commission decides to apply OAR § 860-038-0080(1)(b) in the manner recommended by ICNU, it merely needs to add the prudence adjustments shown in Table 1 to the market value adjustments. The total adjustment would then equal the OAR § 860-038-0080(1)(b) (market value) adjustment.

III. NET POWER COST ISSUES

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

A. Net power costs are the variable production costs related to fuel and purchased power expenses net of power sales revenue. Net power costs comprise a substantial portion of overall revenue requirement and therefore are a significant component of PacifiCorp's proposed base rates. In Docket No. UE 147, the Company requested $610.7 million (total Company basis) in net power costs. In the Stipulation in that case, the Company agreed to final net power costs of $598 million.[7/] In this case, the Company is now requesting $785 million based on the Partial Stipulation and its original filing. Based on the Oregon allocators used in each case, the increase in net power costs is responsible for approximately $46 million of total revenue requirements.[8/]

Q. DID ICNU SETTLE ANY NET POWER COST ISSUES IN THE PARTIAL STIPULATION?

A. Yes, for the most part ICNU's net power cost adjustments regarding PacifiCorp's GRID model were settled. The issues that follow were reserved by ICNU in the Partial Stipulation.

7/ Docket No. UE 147, Stipulation Paragraph 5.
8/ 785*.277-598*.286 = 46.4 million.

<u>Georgia-Pacific Camus Contract</u>

Q. HAS THE COMPANY CORRECTLY MODELED THE GEORGIA PACIFIC ("GP") CAMUS CONTRACT?

A. No. The Company has included the unadjusted contract cost of power it received from GP, but has ignored various offsets it receives from the customer. This issue was specifically reserved in the Partial Stipulation.

Q. EXPLAIN THE PAYMENT TERMS OF THE CONTRACT?

A. While the contract is fairly complex, GP supplies steam to a generator (owned by PacifiCorp), and PacifiCorp pays a "Steam Royalty" to GP. The Steam Royalty is equal to a contract price, less certain offsets. In computing the cost of power from GP in this case, PacifiCorp has ignored the offsets.

This is a substantial problem because the contract does not require PacifiCorp to pay for any of power from the facility, unless it exceeds the "revenue requirement" of the project, and other conditions related to GP's average price for power are also met. However, in its filing, PacifiCorp ignored GP-Camas contract offsets. Correcting this oversight reduce net power costs by the amount shown in Table 1.

Q. PACIFICORP HAS ACKNOWLEDGED THIS ERROR IN RESPONSE TO ICNU AND OPUC DATA REQUESTS. HOWEVER, IT CONTENDS THE ERROR IS OFFSET BY A FUEL HANDLING ERROR. PLEASE COMMENT.

A. While the Company makes this claim in ICNU 17.7, in ICNU 17.5 it admits the fuel handling issue had no relationship to the GP Camas error. Exhibit ICNU/109. In ICNU 17.4 the Company indicated it could not provide any workpapers support for the fuel handling error. Exhibit ICNU/109. While the

Company has not amended its filing to reflect the alleged fuel handling error, given this, I suggest the Commission ignore it.

Thermal Deration Factors

Q. EXPLAIN THE SIGNIFICANCE OF THERMAL DERATION FACTORS IN GRID.

A. In GRID, thermal deration factors (also called outage rates) control the amount of generation available from thermal units. The more energy available, the lower net power costs. If a generator has an average outage rate of 5%, GRID assumes a thermal deration factor of 95%. This means that only 95% of the unit's capacity is available to produce energy. The remaining capacity is assumed to be permanently on outage. In its initial filing, the Company used a compilation of outages over the most recent forty-eight month historical period (April 2000 to March 2004) to compute the deration factors for its thermal plants.

Q. IN THE MARCH 15, 2005 GRID UPDATE, THE COMPANY PROPOSED TO USE A MORE RECENT FORTY-EIGHT MONTH PERIOD TO COMPUTE OUTAGE RATES AND HEAT RATES IN GRID. DO YOU AGREE WITH THIS PROPOSAL?

A. No this item is a reserved issue listed in the Partial Stipulation in Paragraph 5(a)(1). This Commission should reject this "last minute" selective update of GRID. There are several reasons for this recommendation. First, outage rates are computed from thousands of individual outage events. It can take substantial discovery and time to determine whether certain outages may have been the result of mismanagement or imprudence. By making this change to the data so late in the proceeding (only two weeks prior to the date settlement positions were required to be filed) it seriously disadvantages parties who wish to challenge the prudence of outages. This is an even more serious problem when the Company updates its GRID study historical period, it changes much of the underlying data used in preparation of its case. There were a large number of ICNU data requests issued that sought this data. Though our requests were continuing, the Company refused to provide updates to these data requests when it changed the GRID inputs without issuance of a new data request. Owing to the time limits in the case, this meant that there would be very little time for analysis of this information after the update was filed.

Second, the proposed data was based on the 48 months ended September 30, 2004. There is no apparent reason why this information could not have been available at the time of the February GRID update. Third, this data is clearly not the only information that could have changed in time for inclusion in the March 15 filing. The Company had the option of using updated information that increased power costs, while not using updated data that decreased power costs, or other components of its overall rate request. Fourth, in prior discussions I had with the Company no mention was ever made regarding an update to these kinds of inputs. Instead it was indicated that the March update would be limited to new contracts for fuel and power. Had I been aware of this proposal, I could have conducted preliminary discovery on these changes, as I did in the case of new contracts.[9/] I am left with a clear feeling that the Company was simply try to place ICNU and other parties at a disadvantage in proposing this data update.

Finally, the presence of multiple updates of the GRID model greatly complicates the efforts of analysts trying to analyze the PacifiCorp rate filing.

[9/] *See* ICNU's Seventh Set of Data Requests to PacifiCorp.

The Commission should make it clear that it will allow only limited updates in specific areas in future cases. For all these reasons, I recommend the Commission disallow this proposed data change. This adjustment is shown on Table 1.

Q. PGE HAS BEEN ALLOWED TO MAKE UPDATES TO OUTAGE RATES IN ITS APRIL 1 RVM FILINGS. WHY SHOULDN'T PACIFICORP BE ALLOWED TO MAKE A COMPARABLE UPDATE IN MARCH?

A. I will discuss RVM in more detail later. However, it is not proven that PGE's approach amounts to the "best practices" a regulatory commission might follow. More significantly, in the RVM cases, parties generally have not had to file testimony until late June to Mid August (3-5.5 months), thus affording substantial time to address such issues. In this case, the Company would only allow parties two weeks before settlement positions were due and about six weeks before testimony was due.

Q. HAVE YOU IDENTIFIED ANY OUTAGES THAT SHOULD BE EXCLUDED FROM THE FOUR-YEAR ROLLING AVERAGE?

A. Yes. Again, this is a reserved issue in Paragraph 5(a) of the Partial Stipulation. I have identified a major problem in PacifiCorp's calculation of outage rates for GRID. This problem concerns the outages that occurred during the UM 995 deferral period, from November 2000 to September 2001. This period includes the Hunter Unit 1 outage from November 2000 to May 2001, which the Company has already reversed from its calculation of outage rates.

Q. WHAT IS THE BASIS FOR REVERSING THE HUNTER OUTAGE?

A. Mr. Widmer does not explain this in his direct testimony. However, the same adjustment was also made in Docket No. UE 147. In that case, Mr. Widmer testified as follows:

> Because the Company is recovering the cost of the catastrophic Hunter unit 1 outage through the treatment adopted in UM 995, the Company has excluded that outage from its 48-month outage calculation.

Re PacifiCorp, OPUC Docket No. UE 147, Direct Testimony of Mark Widmer, at 12.

Similarly, in the most recent Utah rate cases, the Company has reversed the Hunter outage. However, in the states where the Company did not collect for the Hunter outage via a deferral mechanism, the Company included the event in computing thermal outage rates. Mr. Widmer explained this in the 2003 Washington rate case by stating, "*The Company's outage rate modeling is simply a four-year amortization of outage costs*." *See* Re PacifiCorp, Washington UTC Docket No. UE-032065, Rebuttal Testimony of Mark Widmer at 37; *see also* Exhibit ICNU/110 (PacifiCorp response to ICNU DR No. 13.49 in Washington Docket No. UE 032065). Because Mr. Widmer contended that Washington had not already paid for Hunter outage costs, he did not remove it from the computation of outage rates.

Q. WAS THE HUNTER OUTAGE THE ONLY GENERATOR OUTAGE THAT OCCURRED DURING THE 48-MONTH PERIOD?

A. No. There were many other events, no different than the Hunter outages, except for their severity. All outages that occurred during the UM 995 deferral period increased net power costs, just like Hunter, and customers are paying for those costs in exactly the same manner as the Hunter outage.

Q. HAS THE COMPANY MADE ANY ADJUSTMENTS TO REVERSE THE REMAINING DEFERRAL PERIOD OUTAGES?

A. No. While the Company acknowledges that recovery of Hunter outage costs via the deferral and through the use of higher outage rates in GRID would amount to a "double recovery," it has not made any adjustments to remove the other outages that occurred during the UM 995 deferral period. There is simply no possible logical explanation as to why one outage should be removed, while other outages should not, particularly in light of the PacifiCorp testimony in Washington that the purpose of the 48-month rolling average methodology is to amortize the cost of prior outages. Because these costs are already being recovered, their inclusion in the GRID study amounts to a "double count."

Q. WHAT IS YOUR RECOMMENDATION?

A. The Commission should reverse all outages that occurred during the deferral period from the 48-month rolling average. This will eliminate the double recovery of such outage costs.

Q. OWING TO THE SHARING MECHANISM AND DEADBAND BUILT INTO THE UM 995 DEFERRAL, RATEPAYERS HAVE NOT NECESSARILY PAID 100% OF THE COST OF THE EXCESS POWER COSTS. DOES THIS IMPLY THAT LESS THAN 100% OF THESE OUTAGE COSTS SHOULD BE REVERSED IN GRID?

A. No. The Commission made a policy decision that limited recovery of the excess power costs in UM 995. It is important to realize that the deferral in UM 995 was an *extraordinary* allowance by the Commission in the case of very unusual circumstances. The normal status quo is for companies to absorb all excess power costs that occur outside of test years. Under more normal circumstances, the Company would not have recovered *any* excess power costs during that time. The

Commission granted recovery on the basis of many important considerations. It should not now reverse any part of that decision.

Further, the Company is proposing a full reversal of Hunter outage costs, not a partial one. Other outages should not be treated any differently. Finally, during the deferral period, market prices were much higher than assumed in the GRID study. Even though less than 100% of all outage costs may have been recovered in the past, the amount recovered is substantially more than the current level of cost built into GRID.

Q. DO YOU RECOMMEND THE COMMISSION ACCEPT THE THERMAL RAMPING AND STATION SERVICE ADJUSTMENTS IN THE FEBRUARY GRID UPDATE?

A. No. These are also issues reserved in Paragraph 5(a)(3) and (5). These are adjustments proposed by the Company ostensibly to better represent the operation of thermal units. They were motivated by a mistaken assumption on the part of the Company that GRID was producing an excess of coal-fired generation. PPL/604, Widmer/2-3. To address the ramping issue, PacifiCorp creates "phantom outages" inflating its outage rates. To address Station Service during outages, the Company adds a zero revenue sales transaction to the model.

Q. IS MODELING OF STATION SERVICE DURING OUTAGES AND THERMAL RAMPING IN THE MANNER USED BY THE COMPANY STANDARD INDUSTRY PRACTICE?

A. No. Based on my more than twenty-five years experience in working with various production cost models, this approach is extremely unusual, and contrary to standard industry practice. NERC publishes a standard formula for computation of forced outage rates, and the approach proposed by the Company is inconsistent with the NERC formula.

Q. ARE YOU AWARE OF ANY INSTANCE WHERE A UTILITY PROPOSED TO INCLUDE ENERGY LOST DUE TO RAMPING IN THE OUTAGE RATES USED IN A POWER COST MODEL?

A. There is only one case that I am aware of. In Docket No. UE 139, Portland General Electric Company ("PGE") proposed a similar modification to outage rates for the Colstrip plant to solve a similar assumed problem of generation from its model exceeding actual ("lost generation"). In that case, the Commission flatly rejected the PGE proposal:

> ICNU disapproves of PGE's calculations in modeling planned outages for the Colstrip plant. ICNU notes that the North American Electric Reliability Council (NERC) has promulgated a standard equation to estimate the forced outage rate of a particular plant. In estimating the forced outage rate for Colstrip, however, PGE modified NERC's standard equation by substituting the plant's capacity factor (CF) for its equivalent availability factor (EAF) ICNU contends that PGE's deviation from standard industry practice is unjustified and arbitrarily inflates PGE's net variable power cost estimate by $1.5 million.
>
> PGE explains it made the adjustment because it obtains less energy from Colstrip than one should expect from the plant's EAF. PGE highlights that it has normally received 1 to 4 percent less generation—based on the plant's CF—than would be expected—given the plant's EAF. To account for this, PGE assigns the "missing generation" to unplanned outages. PGE has not identified any specific reason why the generation at Colstrip has fallen short of potential levels, but speculates that up or down ramping periods, generation variances including minor forced derations, or transmission pathway deratings may be responsible.
>
> * * *
>
> While it appears that an aberration exists in PGE's system that prevents the company from obtaining expected generation levels from the Colstrip plant, we are not convinced that creating "phantom outages" is the appropriate solution. First, PGE's proposed adjustment violates standard industry practice and is contrary to the company's own forecasting methods that it uses for other plants. Second, PGE's adjustment fails to account for the fact that a plant's CF, by definition, will never exceed its EAF, even those that run continuously.

> We are also troubled by PGE's decision to make this adjustment despite the fact that it is unable to identify the source of the generation shortfall or to quantify its effect. If the loss of energy from Colstrip is due to minor forced derations as PGE speculates, the company should be able to modify Monet to capture these derations.
>
> For these reasons, we disagree with PGE's adjustment to a standard industry equation used to compute forced outage rates when outages have nothing to do with the alleged problem.

Re PGE, OPUC Docket No. UE 139, Order No. 02-772 at 23-24 (Oct. 20, 2002) (internal citation omitted).

Q. ARE YOU AWARE OF ANY CASE WHERE A COMPANY HAS MODELED STATION SERVICE DURING OUTAGES AS A ZERO REVENUE SALES TRANSACTION?

A. I can't recall a single case where this has been done. This approach is clearly far outside of standard industry practice and should also be rejected.

Q. IS THERE ANOTHER REASON WHY THE COMMISSION SHOULD REJECT THE STATION SERVICE AND THERMAL RAMPING ADJUSTMENTS?

A. Yes. The support for these adjustments lies in a misperception that GRID was overstating coal-fired generation. This occurred because GRID presents a naïve comparison of its projected coal-fired generation with the four-year average for the period ended December 31, 2004. However, a more proper comparison would be between the GRID projections and actual generation for the four-year period ended March 31, 2004, and a GRID run using loads consistent with those for the same four-year period. Because the Company did not perform a proper comparison in its February update, Mr. Widmer mistakenly concluded that GRID overstates coal-fired generation. Consequently, there is no sound basis for these adjustments, and they should be rejected.

Q. CAN YOU DEMONSTRATE THIS PROBLEM BASED ON COMPARISON OF GRID RESULTS TO ACTUAL DATA?

A. Yes. A proper comparison would be between the GRID projections and actual generation for the four-year period ended March 31, 2004.

Q. WHY SHOULD GRID COMPARE PROJECTED COAL-FIRED GENERATION WITH THE ACTUAL FOR THE FOUR YEARS ENDED MARCH 31, 2004?

A. The outage data used in the initial filing and the February GRID is based on that four-year period. Comparison to any other period is incorrect because generators would have a different pattern of outages. The period used in GRID understates actual coal-fired generation due to use of the incorrect period.

Q. EXPLAIN THE GRID COMPARISON OF ACTUAL TO PROJECTED COAL-FIRED GENERATION.

A. This is shown on Exhibit ICNU/106. This presents the actual coal-fired generation for the four-year period ended March 31, 2004, taken directly from the hourly generator logs.[10/] An adjustment to restore the generation lost during the Hunter outage is included because GRID also reverses the Hunter outage.

Because test year loads substantially exceed the actual loads used during the four-year historical period, it is necessary to run GRID using load levels consistent with the historical levels. I also use an extremely poor hydro scenario to mimic the poor hydro conditions of the past several years. Because this reduces total net load, it also reduces coal-fired generation. The exhibit shows the results of a GRID run based on loads with energy equal to the four-year average.

10/ These are the same logs used by the Company to develop its thermal ramping and station service adjustments as will be discussed later. The figures in the exhibit already reflect the generation lost due to station service and ramping.

Based on this comparison, the coal units in GRID are actually producing 44.2 and 44.6 million MWh per year for the February and March updates respectively. Over the four-year historical period, the adjusted coal-fired generation was 44.96 million MWh. As a consequence, the modeling assumptions used by the Company actually result in a substantial understatement of coal-fired generation.

Q. ARE YOU DENYING THAT RAMPING AND STATION SERVICE ABSORB SOME OF THE AVAILABLE COAL-FIRED GENERATION?

A. No. I am pointing out that Mr. Widmer's proposed "solution" to this problem is unnecessary, because the problem is a *deficit* of coal-fired generation in GRID, not a *surplus*. Mr. Widmer is solving the wrong problem.

Further, while many production cost models do modeling ramping, they do not do so using adjustments to the outage rates. One of the advantages of an hourly model is that it can model ramping and station service in a realistic manner. However, GRID does not take advantage of these capabilities. Because GRID does not actually model outages in a realistic manner (i.e., it uses deration instead of Monte Carlo or some other probabilistic technique), the Company cannot model ramping in the proper manner. In the end, there is no reason to make the model worse by making unwarranted adjustments to the input data to model phantom outages to account for ramping.

Q. DISCUSS THE DEFERRED MAINTENANCE ADJUSTMENT CONTAINED IN THE FEBRUARY UPDATE STUDY.

A. Again this is a reserved issue in the Partial Stipulation, Paragraph 5(a)(4). NERC defines maintenance outages as those outages that can be deferred to beyond the next weekend, but not longer than until the next planned outage. Under the NERC formula, maintenance outages are not considered part of the forced outage rate. For several years now, the Company has modeled maintenance outages as part of a weekend outage rate. While this is not a "perfect" solution, it captures the likelihood that such outages could be deferred to a more advantageous time (i.e. periods when lower market prices prevail). Mr. Widmer contends that GRID produces too much on-peak coal-fired generation vis-à-vis off-peak coal generation, and that maintenance outages do occur in both on and off-peak periods. PPL/604, Widmer/2.

Q. WHY DO YOU RECOMMEND THE COMMISSION REJECT THIS ADJUSTMENT?

A. This adjustment is conceptually flawed. Because these types of outages are deferrable, potentially until the next scheduled outage, it is unreasonable to include them as part of the weekday forced outage rate. When they are included, they reduce generation during all hours, both peak and off peak. In reality, such outages can be deferred until times when market prices are more favorable. For example, if such a problem requiring a maintenance outage were to occur during a summer heat wave, plant managers could defer the repairs until milder weather (and lower market prices) prevailed.

Q. IS THERE EVIDENCE THAT DEMONSTRATES DEFERRAL OF THIS TYPE OF OUTAGE OCCURS IN ACTUAL PRACTICE?

A. Yes. Based on my review of maintenance outages during the four-year period, I have found that substantially less than average maintenance outage energy losses occur during July and August.[11/] Substantially more than average occurs in

---

[11/] 82% of average.

September.[12/] This clearly demonstrates that operators wait until more favorable load and price conditions prevail before bringing plants down for such repairs. Mr. Widmer's proposed modeling ignores actual practice.

Further, the inclusion of maintenance outages during the weekday outage rate ignores the fact that the great majority of energy lost due to maintenance outages occurs during Low Load Hours ("LLH"). Based on my review of all of the maintenance outages during the four-year period, I have found that 68.5% of all lost energy occurs during LLH. Again, this demonstrates the operators schedule these outages to minimize cost. Mr. Widmer's proposed modeling technique assumes that no such efforts are made. In the end, Mr. Widmer's proposed treatment of maintenance outages is much more problematic than the Company's previous methodology.

Q. DO YOU AGREE WITH THE ADJUSTMENT IN THE MARCH 15, 2005 UPDATE TO USE THE ACTUAL SCHEDULED MAINTENANCE RATHER THAN THE FORTY-EIGHT MONTH AVERAGE?

A. No. This issue was reserved in the Partial Stipulation in Paragraph 5(a)(2). In many respects the reasons I gave above, related to the issue of outage rates, apply here as well. This change comes very late in the game, and no justification of any kind is provided for it. PPL/607, Widmer/2 (the exhibit merely describes the change but does not provide a basis for making it). Further, it has been the Commission's precedent to use a forty-eight month average to develop maintenance schedules for several cases now, and this unsupported adjustment is contrary to that precedent. This clearly appears as an unjustified, opportunistic change to input data. Again, the Company had the opportunity to weigh whether

---

12/ 185% of average.

this adjustment increased or decreased power costs before deciding to make it. This adjustment should be reversed, resulting in the reduction to net power costs in the amount shown on Table 1.

IV. PACIFICORP'S RVM PROPOSAL

Q. EXPLAIN THE RELATIONSHIP BETWEEN DIRECT ACCESS AND THE TRANSITION ADJUSTMENT.

A. Ms. Omohundro describes the Transition Adjustment as the difference between the weighted market value of the energy previously used to serve direct access customers and the cost of service rate under the customers' specific energy-only tariff schedule. The Company proposes to determine the market value of this energy by comparing the output of two GRID model studies. PPL/700, Omohundro/3.

Q. DOES PACIFICORP HAVE ANY DIRECT ACCESS CUSTOMERS?

A. Based on the order in Docket No. UM 1081, there were no direct access customers at the time that order was issued in September 2004. Only a handful of customers have switched since that time.[13/] The Commission opened UM 1081 in order to address its concern that this may be due to the methodology used by the Company to compute the transition adjustment:

> It is a fact that no eligible PacifiCorp customer has elected to receive direct access service from an ESS. Parties dispute the reasons why customers continue to choose electric energy service from PacifiCorp at cost of service rates, and efforts have been ongoing in this docket to discern whether there are barriers that impede the marketability of direct access. As PacifiCorp's transition adjustment methodology has long been suspected to

[13/] The most recent reports show only 5 commercial direct access customers (18 MW). These customers, however, apparently switched in response to a substantial "shopping incentive" ($5/MWH).

> hinder the economic viability of direct access in the Company's service territory, the formal portion of this docket was opened in order to address this issue.

Re an Investigation to Direct Access Issues, OPUC Docket No. UM 1081, Order No. 04-516 at 9 (Sept. 14, 2004).

While the Commission was apparently unable to reach a conclusion regarding this question, it did determine that a "market even" methodology for computation of an interim transition adjustment should be used. Id. Consequently, the Commission directed the interim transition adjustment be computed to reflect the market value of freed up energy *without any additions or subtractions*. In contrast, in UM 1081, PacifiCorp proposed a "market minus" methodology that would compute the market value of freed up energy based on the revenues obtained from additional sales minus transmission charges. ICNU proposed a "market plus" approach based on the assumption that without direct access loads, PacifiCorp would purchase less power and, as a result, avoid transmission expenses required to wheel the power to the system's load centers.

Q. IS PACIFICORP'S PROPOSED METHODOLOGY REALLY A TRUE "MARKET EVEN" APPROACH?

A. No. The original proposal was really a "market minus" method because of its use of the GRID model to compute the transition adjustment. In fact, under PacifiCorp's original proposal, it would likely be impossible for a customer to benefit by switching to direct access.

Q. PLEASE EXPLAIN.

A. PacifiCorp proposed to use the GRID model to determine the transition adjustment by modeling a scenario with a 25 MW Oregon load reduction to simulate customers who have left for direct access. Based on Ms. Omohundro's Table 1, this load reduction results mainly in reduced purchases, though there are some increased sales, and a small reduction to thermal generation. Based on her Table 1, the average cost per MWH of the decreased thermal generation is far below the average market price of purchases and sales.[14/]

Q. WHY DOES GRID ASSUME THAT SOME OF THE REDUCTION IN LOAD RESULTS IN A TURN-DOWN OF THERMAL UNITS?

A. GRID uses a trading curve dispatch methodology. This means that generators will be dispatched (irrespective of load) if their dispatch cost is less than the hourly market price. If thermal generation exceeds native load, then it is assumed that a spot sale of generation takes place. This is known as "balancing energy" in GRID. However, in GRID, market cap inputs place a limit on the amount of energy that can be sold during graveyard shift hours. As a result, during those hours, GRID assumes the Company has no market for the power, and does not allow any sales to take place.

This modeling approach results in a contradictory situation where PacifiCorp reduces output of coal fired plants with very low running costs, at a time when the balancing price built into the model is much higher.

Q. EXPLAIN THE IMPLICATIONS OF THIS SET OF CIRCUMSTANCES.

A. In effect, PacifiCorp is modeling two market prices, one before the market caps are exceeded, and a lower one after. Effectively GRID assigns the lower valued

---

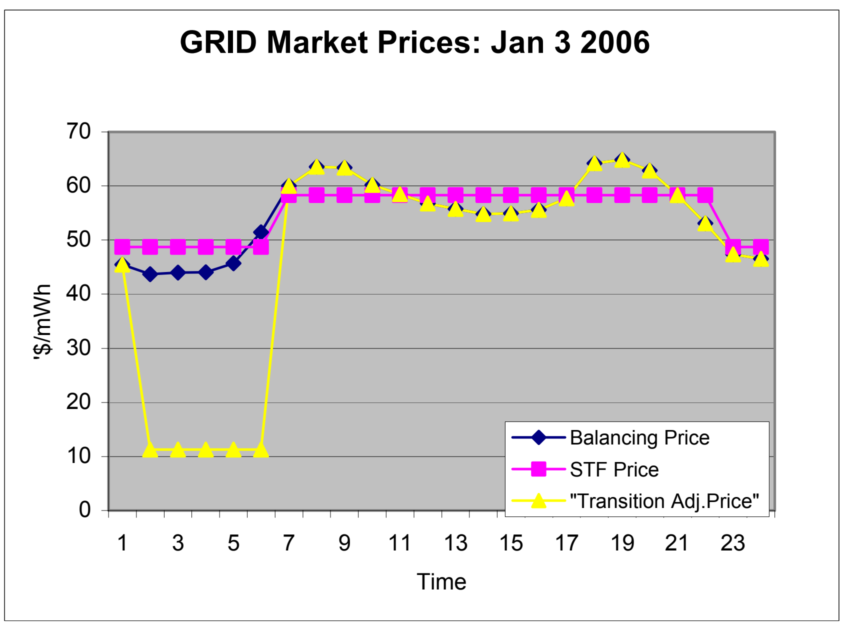
14/ Because the purchases and sales represent both on and off-peak energy, while the reduced thermal generation tends to occur during graveyard shift hours (due to market caps), the prices are not directly comparable. However, the cost of coal-fired energy during the graveyard shift hours is also below the prevailing balancing price assumed in GRID.

generation to direct access customers, resulting in a lower average market value for energy freed up by not serving these customers.

However, any competing ESS would likely have to purchase energy from the market at the price of standard market products. This would be a higher market price than the price GRID assigns to the departing load. Thus, it appears unlikely that any customer would ever benefit by switching to an ESS. In effect, GRID would eliminate the competition for direct access loads before it actually starts.

Q. IS IT POSSIBLE TO ILLUSTRATE THIS PROBLEM VISUALLY?

A. Yes. The figure below shows a comparison of the STF (standard product) price for January 3, 2006, and the hourly balancing price used in GRID.



The chart also shows the "Transition Adjustment" price developed from the GRID simulation based on the 25 MW load decrement. This price is essentially the same as the balancing price for all hours except the graveyard shift. During those hours, market caps force GRID to back down on coal plants rather than reducing market purchases. As a result, the price used in computing the transition adjustment would only be the variable cost of a coal plant during the graveyard shift. This figure is substantially lower than the block purchases price, or the balancing price. In all likelihood, an ESS would have to purchase power at the standard product price, and the balancing price used in GRID will equal the standard product price over all hours in the month. As a result, the transition adjustment price would always be lower than the price paid to serve a direct access customer by an ESS. The "dip" in the transition adjustment price during the graveyard shift hours will serve to make it impossible for an ESS to attract direct access customers. This figure demonstrates that the transition adjustment as computed by the Company will always be a "market minus" approach in that it would always be below the market price for standard products, or even balancing energy.

Q. DOES THE PARTIAL STIPULATION ADDRESS THIS PROBLEM?

A. It provides a partial solution by relaxing market caps in an amount roughly equal to the amount of direct access load assumed in the transition adjustment calculation. Intuitively, I would expect that this will reduce the problem described above. However, it is not intuitively clear whether the Partial Stipulation methodology will completely eliminate this problem. For this reason, ICNU agrees that *if* the Commission adopts the PacifiCorp proposal, this adjustment should be made. However, ICNU believes the PacifiCorp method, even with this adjustment is not satisfactory.

Q. HOW SHOULD THE COMMISSION RESOLVE THIS ISSUE?

A. There are two alternatives for the Commission to consider. In its Order in Docket No. UM 1081, the Commission advocated a "market-even" rather than "market-minus" methodology for the interim adjustment. The original PacifiCorp proposal amounts to a "market-minus" method as it would always produce a result lower than the cost of a standard market product. At a minimum, the Company must demonstrate in its rebuttal testimony, that the solution contained in the Partial Stipulation at least provides a true "market even" result. However, ICNU continues to believe a "market plus" method should be applied.

Q. PLEASE EXPLAIN.

A. There are at least two remaining problems. First, GRID does little to simulate transmission costs. The vast majority of transmission costs in GRID are fixed, and changes in balancing energy have little impact on transmission costs. Thus, GRID does not accurately assess whether reductions in purchases produce lower transmission costs in a scenario where direct access load leaves the system. As shown in Ms. Omohundro's Table 1 reductions in purchases are equal to 2.5 times the increases in sales implying transmission cost savings due to decreased purchases will far outweigh the added costs of increased sales.

The second problem with use of GRID is even more intractable. GRID is an operational simulation model, meaning it will attempt to simulate changes in operations resulting from a change in conditions (whether it be lower loads, plant outages, etc.). However, GRID does not simulate changes in planning that might have a much more important impact on operations. GRID essentially takes the slate of resources, and short-term transactions as fixed. Were 25 MW of load to depart the system, planners would respond. First, the portfolio of short-term firm transactions would be altered. Eventually, the long-term resource mix would change as well.

Because GRID assumes that all resources are "locked-in," the only variables it can change, in response to changes in load, are balancing transactions or the thermal unit dispatch. Thus, GRID really oversimplifies the interplay between planning and operation. This creates a "self-fulfilling prophecy" whereby direct access never leads to a change in resource plans, thus the value of freed up resources is always too low to allow competition to get started. The Commission recognized this dilemma in its order in UM 1081:

> Second, we acknowledge the underlying dilemma at the core of the dispute about valuation of transmission resources. Avoiding the acquisition of power rather than disposing of acquired power by market sale results in a higher transition credit valuation as transmission costs to and from the market are not incurred. Supporters of a market-plus approach, therefore, argue that PacifiCorp should anticipate direct access load departure and not plan for it. PacifiCorp counters, however, [that it] balances its system on a 24-month rolling basis and plans for load departure only upon actual notice. Operationally, therefore, PacifiCorp is likely to always be in load balance when responding to direct access load departure, making the market-plus approach almost always inapplicable: The problem is further compounded by the nature of PacifiCorp's transmission rights and the dispute about whether PacifiCorp uses transmission capacity freed up by direct access load.
>
> Our desire is to develop a long-range transition adjustment that values resources based not only on PacifiCorp's actual operational responses, but actual operational responses that are based on appropriate planning. We approve the market-even transition adjustment methodology as an interim approach based upon PacifiCorp's current resource position. In the near term, through 2006, PacifiCorp is in resource balance and does not need to purchase additional energy resources. On a going forward basis, however, as PacifiCorp plans to cover anticipated resource deficiencies, a valid question is raised whether PacifiCorp should

> anticipate direct access load in order to avoid acquisition for departing load. We therefore direct PacifiCorp together with Staff and parties, to address how GRID model projections change if PacifiCorp's operational assumptions change.

Re an Investigation into Direct Access, Order No. 04-516 at 12.

Unfortunately, as discussed above, GRID does not have the capability to anticipate changes in operational assumptions. Therefore, it is a questionable tool for the Commission's purposes in addressing this problem.

Q. WHAT THEN IS YOUR PREFERRED SOLUTION?

A. A better solution to this problem is to not rely on GRID at all, as it cannot simulate the changes in planning that would occur if the Company were to properly anticipate direct access load. A much less complex solution is to simply recognize that when the system is appropriately planned, departure of direct access load will result in a net reduction in purchases. Thus, the value of freed up resources should simply reflect the cost of a standard market product with additional transmission costs avoided. This assumption is actually supported by GRID in that the model shows reductions in purchases are substantially greater than the increase in sales. The GRID results could be used to compute the changes in standard product transactions in the varying market hubs. Thus, a hub weighted price of standard products would be based on the GRID results.

Q. IS IT REALISTIC TO ASSUME THAT FREED UP LOAD WILL RESULT IN CHANGES TO STANDARD PRODUCT TRANSACTIONS, AS OPPOSED TO CHANGES IN SPOT (OR BALANCING) TRANSACTIONS AS MODELED IN GRID?

A. Yes. Even though PacifiCorp contends that its planning is done in advance, a reduction in load due to direct access would provide the Company the opportunity to liquidate positions before they are delivered to the Company. This would eliminate the need for transmission costs required to take those deliveries into the system. Under the GRID logic, it is assumed that standard product transactions are fixed, and cannot be altered in response to reductions in load. Thus, in the GRID approach, products are wheeled into the system whether needed or not, and may later have to be wheeled out to make a spot sale. This is not a realistic depiction of actual practice.

Q. PLEASE EXPLAIN HOW YOUR SOLUTION WOULD WORK?

A. I would use a weighted average price for standard products reflecting multiple hubs. Based on weights derived from GRID, this would result in a transition adjustment price of $46.38/MWH (September 30, 2004 trading curve) plus a transmission adder of $1.08/MWH. *See* Confidential Exhibit ICNU/107C. This compares to PacifiCorp's original recommended TA of $43.68/MWH based on Ms. Omohundro's Table 1.[15/]

Q. PLEASE CONSIDER THE PACIFICORP PROPOSAL TO DO AN ANNUAL RVM PROCESS SIMILAR TO PGE'S RVM. DO YOU AGREE WITH THIS PROPOSAL?

A. No. The PGE RVM should not be considered as such a successful model that it should be emulated by PacifiCorp. PGE's RVM has also resulted in ratepayers absorbing a substantial portion of PGE's power cost risk. There is no basis for assuming such a proposal will be beneficial to PacifiCorp's ratepayers.

Further, the PGE RVM has been fraught with numerous problems related to the scope of costs to be included, modeling methods, and prudence issues. The

---

15/ It is not yet known what impact the method contained in the Partial Stipulation will have on the transition adjustment.

RVM process amounts to an abbreviated rate case, in terms of the procedural schedule only. In terms of the complexity of issues, and amount of time and discovery required, it differs little from a general rate case. Further, the use of numerous updates has lead to a variety of problems and conflicts. In just one example, PGE introduced new capacity tolling contracts into its RVM study in November 2004. This created a substantial controversy because these resources didn't produce any energy in the Monet model. In the end, there was no avenue for parties to address the issue, and ratepayers are now being charged for the cost of resources that may be imprudent or unreasonable. Exhibit ICNU/108 presents certain documents related to this issue.

However, at the start of RVM, PGE's Monet model was more mature, and better understood than the GRID model is even now. The Partial Stipulation in this case notwithstanding, there are many major modeling issue yet unresolved in GRID. Only a full rate case provides the time and process necessary for a full review of all power cost issues.

Q. IS AN ANNUAL RVM UPDATE NECESSARY TO DEVELOP A TRANSITION ADJUSTMENT?

A. No. The primary argument for having an annual RVM and transition adjustment update is that it would prevent ratepayers from subsidizing customers switching to direct access if market prices decline. However, if net power costs increase, ratepayers assume risks the shareholders would ordinarily bear. Given that there are apparently only a handful of current direct access customers, it seems rather unnecessary to require all customers have the power rates change every year to avoid a hypothetical subsidy to a few customers. In this case, the risks assumed by ratepayers are quite unbalanced if an RVM is adopted. There is a risk of a small subsidy occurring between groups of ratepayers, as compared to a large risk that ratepayers will assume risks more appropriately placed on investors. Further, an annual RVM and update of the transition adjustment by itself will not promote direct access. The number of customers on direct access will likely depend much more on how the Commission sets the transition adjustment (i.e. "market even," "market plus" or "market minus") than how often the adjustment is recomputed. Even if a "market minus" adjustment were recomputed each month, there would still be no incentive for customers to switch to direct access because an ESS could never match the PacifiCorp price.

Since the resolution of UE 116 on September 7, 2001 the transition adjustment has only changed once.[16/] Unless the Commission adopts a fundamentally different approach, there is no basis for assuming substantial loads will switch to direct access in the foreseeable future. Thus, an annual RVM update would really amount to a hypothetical tail, wagging a real dog. This process really amounts to a regulatory complication that the Commission and ratepayers can do without.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes

16/ With the issuance of Order No. 04-516 in September 2004, the UE 116 transition adjustment changed.

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity. In addition, I have been involved in many projects over the past several years concerning the modeling of market prices in various regional power markets.

In January 2000, I founded RFI Consulting, Inc. whose practice is comparable to that of my former firm, J. Kennedy and Associates, Inc.

The testimony that I present is based on widely accepted industry standard techniques and methodologies, and unless otherwise noted relies upon information obtained in discovery or other publicly available information sources of the type frequently cited and relied upon by electric utility industry experts. All of the analyses that I perform are consistent with my education, training and experience in the utility industry. Should the source of any information presented in my testimony be unclear to the reader, it will be provided it upon request by calling me at 770-379-0505.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock - Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Public Utilities Fortnightly - "PoolCo and Market Dominance", December 1995 Issue

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470-EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Phase-in of nuclear unit.
2/85	I-840381	PA	Phila. Area Ind. Energy Users' Group	Philadelphia Electric Co.	Economics of cancellation of nuclear generating units.
3/85	Case No. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling fossil generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study , economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General &	Georgia Power Co.	Cancellation of nuclear

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Georgia Public Service Commission Staff		plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7- Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86	9437/ 613	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524- E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87- 013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/88 gas	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel K	Kentucky Util.	Contract termination clause and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements gas & electric, CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning study.
12/90	U-9346	MI	Association of	Consumers Power	DSM Policy Issues.

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
			Businesses Advocating Tariff Equity (ABATE)		
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public	Texas-New Mexico Utility Counsel	Imprudence disallowance. Power Co.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, Performance incentives.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost savings
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder incentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environmental Costs Of electricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial	Tampa Electric Co.	Polk County Power Plant

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Power Users Group		Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost
8/97	96-360-U	AR	AEEC	Entergy Ark. Inc.	Market Prices and Stranded Costs, Cost Allocation, Rate Design
10/97	6739-U	GA	GPSC Staff	Georgia Power	Planning Prudence of Pumped Storage Power Plant
10/97	R-974008 R-974009	PA	MIEUG PICA	Metropolitan Ed. PENELEC	Market Prices, Stranded Costs
11/97	R-973981	PA	WPII	West Penn Power	Market Prices, Stranded Costs
11/97	R-974104	PA	DII	Duquesne Light Co.	Market Prices, Stranded Costs
2/98	APSC 97451 97452 97454	AR	AEEC	Generic Docket	Regulated vs. Market Rates, Rate Unbundling, Timetable for Competition.
7/98	APSC 87-166	AR	AEEC	Entergy Ark. Inc.	Nuclear decommissioning cost estimates & rate treatment.
9/98	97-035-01	UT	DPS and CCS	PacifiCorp	Net Power Cost Stipulation, Production Cost Model Audit
12/98	19270	TX	OPC	HL&P	Reliability, Load Forecasting
4/99	19512	TX	OPC	SPS	Fuel Reconciliation
4/99	99-02-05	CT	CIEC	CL&P	Stranded Costs, Market Prices
4/99	99-03-04	CT	CIEC	UI	Stranded Costs, Market Prices
6/99	20290	TX	OPC	CP&L	Fuel Reconciliation
7/99	99-03-36	CT	CIEC	CL&P	Interim Nuclear Recovery
7/99	98-0453	WV	WVEUG	AEP & APS	Stranded Costs, Market Prices
12/99	21111	TX	OPC	EGSI	Fuel Reconciliation
2/00	99-035-01	UT	CCS	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
5/00	99-1658	OH	AK Steel	CG&E	Stranded Costs, Market Prices
6/00	UE-111	OR	ICNU	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
9/00	22355	TX	OPC	Reliant Energy	Stranded cost

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service
12/00	99-250-U	AR	Tyson Foods	Ozarks Elec. Coop	Cost of Service
01/01	00-099-U	AR	Tyson Foods	SWEPCO	Rate Unbundling
02/01	99-255-U	AR	Tyson Foods	Ark. Valley Coop	Rate Unbundling
03/01	UE-116	OR	ICNU	PacifiCorp	Net Power Costs
6/01	01-035-01	UT	DPS and CCS	PacifiCorp	Net Power Costs
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT	CCS	PacifiCorp	Certification of Peaking Plant
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UE-032065	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS		PacifiCorp Net power costs
02/05	UE-165	OP	ICNU	Portland General	Hydro Adjustment Clause

Exhibit ICNU/102

Excerpt from the Feb 8, 2000 airing of Nova, on PBS

Derived by economists Myron Scholes, Robert Merton, and the late Fischer Black, the Black-Scholes Formula is a way to determine how much a call option is worth at any given time. The economist Zvi Bodie likens the impact of its discovery, which earned Scholes and Merton the 1997 Nobel Prize in Economics, to that of the discovery of the structure of DNA. Both gave birth to new fields of immense practical importance: genetic engineering on the one hand and, on the other, financial engineering. The latter relies on risk-management strategies, such as the use of the Black-Scholes formula, to reduce our vulnerability to the financial insecurity generated by a rapidly changing global economy.

At the very height of their careers, Merton and Scholes were already multi-millionaires. Five years earlier, John Meriwether, the legendary bond trader at Salomon Brothers, had enticed Scholes and Merton to join him and 13 other partners in a new company he was launching, Long Term Capital Management. In 1994, Business Week introduced the public to the "Dream Team" Meriwether had assembled.

Within months they had raised three billion dollars and were ready to start investing across the globe. They set up not on Wall Street but far away from ordinary traders, in Greenwich, Connecticut. From their headquarters they devised one of the most ambitious investment strategies in history. Its success depended on absolute secrecy. Not even their investors were allowed to know what they were doing. Analyzing historical data, they used probability to bet that key prices would move roughly as they had in the past. To protect themselves against unwanted risk, they relied on an insight of the Black-Scholes formula - dynamic hedging. In effect, offsetting risk by taking bets in the opposite direction. Supremely confident, LTCM placed vast sums of money on the markets.

"It was as though the world was behaving exactly the way it had been writ on the blackboard. Long Term Capital thought that they had discovered the path to Nirvana. Here they are doing their day-to-day activities, playing golf in lush Greenwich or attending hedge fund conferences in Bermuda, or raising funds in Cannes. And then slowly and totally unexpectedly, a change in the market dynamics began to become apparent."

In the summer of 1997, across Thailand, property prices plummeted. This sparked a panic that swept through Asia. As banks went bust from Japan to Indonesia, people took to the streets - events so improbable they had never been included in anyone's models.

"Everyone in the marketplace thought the sky was falling, and there was instant reaction. The market broke, then rallied, then broke, then rallied. We didn't know what to believe."

As prices leapt and plunged as never before, the models traders used began to give them strange results, so they relied instead on their instincts. In a time of crisis, cash is king. Traders stopped borrowing and dropped risky investments.

"Models that they were using, not just Black-Scholes models, but other kinds of models, were based on normal behavior in the markets and when the behavior got wild, no models were able to put up with it."

"Although their models told them that they shouldn't expect to lose more than 50 million or so on any given day, they began to lose 100 million and more, day after day after day till finally there was one day, four days after Russia defaulted, when they dropped half a billion dollars, 500 million in a single day."

In Greenwich, LTCM faced bankruptcy, but if the company went down, it would also take with it the total value of the positions it held across the globe - by some accounts $1.25 trillion, the same amount as the annual budget of the US government. The elite of Wall Street would suffer heavy losses. The Federal Reserve Bank called upon the world's top financial regulators to discuss the crisis.

Peter Fisher, a Federal Reserve Regulator said, "What really was the shock for me when we went up to Long Term Capital and the partners gave us an overview of their positions and the risks and the pressures they were under, was the extraordinary scope of the risks that they had taken on, the breadth of the portfolio, and yet how utterly their effort to diversify the portfolio had failed them, how - that this wide set of positions across all markets had all come in, were all behaving the same way. Everything had come up heads.

Math doesn't drive financial markets, people drive financial markets, and people are not predictable. We do not yet have a universal theory of human behavior or human motivation. Given that that's so, we're not likely to have robust models of financial market behavior that will always work, and I think the hubris of the mathematician is to ignore that fact. [emphasis added]"

Don Furman
Senior Vice President
Regulation & External Affairs
Direct (503)813-5525
Fax (503)813-7277

825 N.E. Multnomah, Suite 2000
Portland, Oregon 97232
(503) 813-5000

PACIFICORP
PACIFIC POWER UTAH POWER

May 28, 2004

Ken Canon, Executive Director
Industrial Customers of Northwest Utilities
825 NE Multnomah, Suite 180
Portland, OR 97232

Re: PacifiCorp West Valley Generation Facilities

Dear Ken:

I appreciate the opportunity to respond to your letter to Judi Johansen of May 12 regarding PacifiCorp's West Valley Project. I received a similar letter from Lee Sparling on May 24. I have enclosed my response to him, which addresses the issues raised in your letter. In summary, PacifiCorp believes that the West Valley lease is an important and cost-effective resource in reliably meeting our load service obligation. One of the additional attractive qualities of the lease is the degree of flexibility it provides PacifiCorp. In this instance, PacifiCorp intends to take advantage of that flexibility by providing written notice of termination prior to June 1, 2004. This step will provide the Company a four-month window to evaluate whether to terminate the lease as of May 31, 2005 or rescind the termination and permit the lease to continue.

As I indicated in my letter to Mr. Sparling, we propose to provide informal updates or briefings to Staff throughout the summer along the Company's path to a decision. We are pleased to include ICNU in these briefings as well.

Please contact Christy Omohundro or me if you have further questions or comments.

Sincerely,

Don Furman
Senior Vice-President

cc: Chairman Lee Beyer
Commissioner Ray Baum
Commissioner John Savage
Lee Sparling
Marc Hellman
Judi Johansen
Christy Omohundro

Don Furman
Senior Vice President
Regulation & External Affairs
Direct (503)813-5525
Fax (503)813-7277

825 N.E. Multnomah
Portland, Oregon 97232
(503) 813-5000

PACIFICORP
PACIFIC POWER UTAH POWER

May 28, 2004

Lee Sparling
Director, Utility Program
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: PacifiCorp West Valley Generation Facilities

Dear Lee:

This responds to your letter of May 24, 2004 regarding the West Valley lease.

Background

The Staff investigated the West Valley lease in UI 196. In the Staff Report, adopted by the Commission in Order 02-361, Staff recommended approval of the Company's request to enter into the West Valley lease with West Valley Leasing Company (a subsidiary of PPM) based upon its conclusions that the lease met the Commission's "lower of cost or market" transfer policy and that PacifiCorp was "paying a fair and reasonable price under the Lease." UI 196, Staff Report at 8 (May 22, 2002).

Consistent with the Staff's findings, the West Valley lease has proven to be an important and economic resource for the Company, providing benefits to the overall system in the form of lower net power costs and increased reliability. In the Stipulations approved by the Commission in Dockets UE 134 and UE 147, the lease was included in PacifiCorp's net power costs (in the latter case, the parties did agree to adjust Oregon allocation factors to address certain Utah-based resources, including the West Valley lease).

PacifiCorp has acquired and planned other resource additions since the Oregon Commission approved the West Valley lease, including a contract with Deseret Generation & Transmission Cooperative and its Currant Creek plant (which will come on line in two phases - 2005 and 2006). Notwithstanding these additions, the Company is facing a system short position, as shown in the most recent IRP Update. Thus, the need for the West Valley lease appears to have increased, rather than decreased, since the Commission originally approved the lease.

Termination Option

The provisions of the West Valley lease allow the Company to terminate the lease in year three or in year six. The Company's first option to terminate the lease is prior to June 1, 2004. Under the lease, the Company may rescind the termination prior to September 30, 2004. If the Company does not rescind such a termination notice then the lease would terminate May 31, 2005, and the Company would forego the 200 MW West Valley resource thereafter (unless the Company exercises its parallel purchase option).

In reviewing the West Valley lease, Staff commented that "these options provide PP&L with a hedge against changes in market prices and loads in the future and to ultimately decide which is the best economic choice (continue leasing, terminate leasing, or purchase the project.)" UI 196, Staff Report at 5 (May 22, 2002). PacifiCorp agrees that the flexibility of the West Valley lease is one of its attractive features.

PacifiCorp's Position on Termination

PacifiCorp has decided to take advantage of the flexibility of the West Valley lease by providing PPM Energy written notice of its termination prior to June 1, 2004. This step will provide the Company a four-month window to evaluate whether to terminate the lease as of May 31, 2005, or rescind the termination and permit the lease to continue. While PacifiCorp believes that the West Valley lease may very well remain its best option for reliably meeting a portion of its resource needs, PacifiCorp intends to conduct a robust review of this issue over the summer, including an evaluation of short-term market opportunities.

PacifiCorp's Position on a Proposed Staff Investigation

It is not clear whether your letter suggested a Staff investigation out of concerns that PacifiCorp would not trigger the termination option by June 1, concerns that PacifiCorp would not evaluate the West Valley lease against other market alternatives, or both. We think that the fact that PacifiCorp is planning to take both of these steps should obviate the need for any kind of formal Staff investigation. This is especially true given the fact that Staff and other parties will have an opportunity to scrutinize whatever decision PacifiCorp makes on the West Valley lease in a subsequent prudency review over the lease expense or the replacement resource expense.

Now that we understand that Staff has an interest in this issue, we are pleased to provide informal updates or briefings throughout the summer along the Company's path to a decision. This kind of informal approach is consistent with past practices in Oregon on resource decisions of this sort. In contrast, a formal investigation on whether a utility should make a certain resource decision is highly unusual in a State that has generally eschewed resource pre-approval.

We hope that PacifiCorp's approach to the West Valley lease termination, along with the Company's willingness to provide informal updates or briefings to Staff during the four-month review window, satisfies the concerns that precipitated your letter. Please contact Christy Omohundro or me if it does not or if we can provide more information.

Sincerely,

Don Furman
Senior Vice-President

cc: Marc Hellman
Ed Busch
Ken Canon, ICNU
Bob Jenks, CUB
Judi Johansen
Christy Omohundro
Paul Wrigley

Davison Van Cleve PC

Attorneys at Law

TEL (503) 241-7242 ● FAX (503) 241-8160 ● mail@dvclaw.com
Suite 400
333 S.W. Taylor
Portland, OR 97204

May 9, 2005

Via Electronic and US Mail

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

Re: In the Matter of PACIFIC POWER & LIGHT Request for a General Rate Increase in the Company's Oregon Annual Revenues
Docket No. UE 170

Dear Filing Center:

Enclosed please find the following items for filing in the above-referenced proceeding on behalf of the Industrial Customers of Northwest Utilities:

- five (5) copies of the Confidential Direct Testimony of Randall Falkenberg, with confidential information in separate envelopes (these copies are unbound to allow for easy integration of the separately provided confidential pages);
- two (2) copies of the Redacted Direct Testimony of Randall Falkenberg;
- five (5) copies of the Direct Testimony of James Selecky; and
- five (5) copies of the Direct Testimony of Kathryn Iverson.

Thank you for your assistance.

Sincerely,

/s/ Christian Griffen
Christian W. Griffen

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Testimonies of Randall Falkenberg, James Selecky and Kathryn Iverson on behalf of the Industrial Customers of Northwest Utilities upon the parties on the service list by causing the same to be mailed, postage-prepaid, through the U.S. Mail. Only those parties who executed the Protective Order are receiving confidential versions of Mr. Falkenberg's testimony.

Dated at Portland, Oregon, this 9th day of May, 2005.

/s/ Christian Griffen
Christian W. Griffen

RATES & REGULATORY AFFAIRS PORTLAND GENERAL ELECTRIC RATES & REGULATORY AFFAIRS 121 SW SALMON STREET, 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com	JIM ABRAHAMSON **-- CONFIDENTIAL** COMMUNITY ACTION DIRECTORS OF OREGON 4035 12TH ST CUTOFF SE STE 110 SALEM OR 97302 jim@cado-oregon.org
EDWARD BARTELL KLAMATH OFF-PROJECT WATER USERS INC 30474 SPRAGUE RIVER ROAD SPRAGUE RIVER OR 97639	KURT J BOEHM **-- CONFIDENTIAL** BOEHM KURTZ & LOWRY 36 E SEVENTH ST - STE 1510 CINCINNATI OH 45202 kboehm@bkllawfirm.com
LISA BROWN WATERWATCH OF OREGON 213 SW ASH ST STE 208 PORTLAND OR 97204 lisa@waterwatch.org	LOWREY R BROWN **-- CONFIDENTIAL** CITIZENS' UTILITY BOARD OF OREGON 610 SW BROADWAY, SUITE 308 PORTLAND OR 97205 lowrey@oregoncub.org
PHIL CARVER OREGON DEPARTMENT OF ENERGY 625 MARION ST NE STE 1 SALEM OR 97301-3742 philip.h.carver@state.or.us	JOAN COTE **-- CONFIDENTIAL** OREGON ENERGY COORDINATORS ASSOCIATION 2585 STATE ST NE SALEM OR 97301 cotej@mwvcaa.org
JASON EISDORFER **-- CONFIDENTIAL** CITIZENS' UTILITY BOARD OF OREGON 610 SW BROADWAY STE 308 PORTLAND OR 97205 jason@oregoncub.org	JOHN DEVOE WATERWATCH OF OREGON 213 SW ASH STREET, SUITE 208 PORTLAND OR 97204 john@waterwatch.org

EDWARD A FINKLEA **-- CONFIDENTIAL** CABLE HUSTON BENEDICT HAAGENSEN & LLOYD LLP 1001 SW 5TH, SUITE 2000 PORTLAND OR 97204 efinklea@chbh.com	DAVID HATTON **-- CONFIDENTIAL** DEPARTMENT OF JUSTICE REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 david.hatton@state.or.us
JUDY JOHNSON **-- CONFIDENTIAL** PUBLIC UTILITY COMMISSION PO BOX 2148 SALEM OR 97308-2148 judy.johnson@state.or.us	JASON W JONES DEPARTMENT OF JUSTICE REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 jason.w.jones@state.or.us
DAN KEPPEN KLAMATH WATER USERS ASSOCIATION 2455 PATTERSON STREET, SUITE 3 KLAMATH FALLS OR 97603	MICHAEL L KURTZ **-- CONFIDENTIAL** BOEHM, KURTZ & LOWRY 36 E 7TH ST STE 1510 CINCINNATI OH 45202-4454 mkurtz@bkllawfirm.com
KATHERINE A MCDOWELL STOEL RIVES LLP 900 SW FIFTH AVE STE 1600 PORTLAND OR 97204-1268 kamcdowell@stoel.com	MATTHEW W PERKINS DAVISON VAN CLEVE PC 333 SW TAYLOR, STE 400 PORTLAND OR 97204 mwp@dvclaw.com
JANET L PREWITT DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM OR 97301-4096 janet.prewitt@doj.state.or.us	GLEN H SPAIN PACIFIC COAST FEDERATION OF FISHERMEN'S ASSOC PO BOX 11170 EUGENE OR 97440-3370 fish1ifr@aol.com
DOUGLAS C TINGEY PORTLAND GENERAL ELECTRIC 121 SW SALMON 1WTC13 PORTLAND OR 97204 doug.tingey@pgn.com	ROBERT VALDEZ PO BOX 2148 SALEM OR 97308-2148 bob.valdez@state.or.us
PAUL M WRIGLEY PACIFIC POWER & LIGHT 825 NE MULTNOMAH STE 800 PORTLAND OR 97232 paul.wrigley@pacificorp.com	

Exhibit ICNU/106
Proper Comparison of GRID to Actual 4 Year Average

February Update	
Unit 4 Year Average Generation Including	
Ramping and Station Service deductions:	44,566,861
Correction for Hunter Outage	396,328
Total 4 Year Average	44,963,189
GRID Generation: 4-Year Historical Loads & Poor Hydro	44,668,305
Less Generation Dedicated to Station Service	-67,177
Net Coal Generation	44,601,128
Difference from Adjusted Actual	-362,061
% Difference	-0.8%
March Update	
GRID Generation: 4-Year Historical Loads & Poor Hydro	44,237,594
Less Generation Dedicated to Station Service	-67,177
Net Coal Generation	44,170,417
Difference from Adjusted Actual	-792,772
% Difference	-1.8%

HARDY MYERS
Attorney General

PETER SHEPHERD
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

November 5, 2004

TRACI KIRKPATRICK
ADMINISTRATIVE LAW JUDGE
OREGON PUBLIC UTILITY COMMISSION
550 CAPITOL STREET, N.E., SUITE 215
P.O. BOX 2148
SALEM, OR 97308-2148

RE: RATEMAKING TREATMENT OF CAPACITY TOLLING AGREEMENTS IN PORTLAND GENERAL ELECTRIC'S 2005 RESOURCE VALUATION MECHANISM (DOCKET UE 161)

Dear Judge Kirkpatrick:

On November 3, 2004, Portland General Electric (PGE) filed a draft MONET run in Docket UE 161. Staff has reviewed the updates made in the November 3rd draft MONET run and has identified the ratemaking treatment of capacity tolling agreements as an issue to bring to your attention. Because of Staff's concerns we request a pre-hearing conference be scheduled next week to further discuss this issue.

As PGE indicated in its cover letter accompanying the November 3rd draft MONET run, the company recently signed two new capacity contracts pursuant to its 2002 Integrated Resource Plan and the associated Request for Proposals. Both of these capacity contracts have delivery periods in 2005 and future years. As a result, PGE has modeled the dispatch of these contracts in the November 3rd draft MONET run.

The cost for each of these contracts is comprised of a capacity charge and an energy charge. PGE pays the capacity charge on a monthly basis whether or not it actually schedules any delivery of energy. For calendar year 2005, PGE estimates that the capacity payments for these two contracts will total $2.174 million. PGE pays the energy charge on a monthly basis for each megawatt-hour (MWh) of delivered energy. Based on its MONET modeling of the dispatch of these contracts, PGE estimates for ratemaking purposes, that it will not dispatch (i.e., not actually use) these contracts in 2005. Therefore, for calendar year 2005 the energy payments for these two contracts are estimated to be zero dollars. Consequently, the total cost of these two contracts that PGE has included in the 2005 RVM is $2.174 million.

The benefit of these contracts is comprised of the company's ability to reduce net variable power costs when market prices of electricity and natural gas make the dispatch of these contracts profitable. Both of these capacity tolling agreements have terms and conditions that suggest that economic dispatch will only occur during periods where the spread between market electricity prices and natural gas prices is extreme. The company, however, models net variable power costs in the MONET model on an expected price basis. Under normal, or expected, price conditions the likelihood that these capacity contracts will be economic to dispatch is low – hence in MONET energy payments modeled to be zero dollars in 2005. The uncertainty surrounding the dispatch of these capacity contracts complicates their treatment in PGE's rates.

Staff believes that the ratemaking treatment implied in PGE's November 3rd draft MONET run creates a significant mismatch between ratepayer costs and benefits. For 2005, PGE is asking its customers to pay $2.174 million in costs. In exchange, because rates are set on an expected price basis, the only benefit that customers could possibly receive is if an extreme price event occurs and the company or an intervening party anticipates the event and files an application for a power cost deferral. Absent that unlikely situation, the benefits of these capacity tolling agreements fall entirely to PGE's shareholders, despite the $2.174 million included in customers' rates.

Permanent remedies to this mismatch of ratepayer costs and benefits include: (1) Abandoning expected price modeling in MONET and implementing expected net variable power cost modeling, or (2) Establishing a permanent power cost adjustment mechanism that appropriately matches costs and benefits on a long-run basis. The first alternative involves an enhancement to MONET. Implementing this alternative in the 2006 RVM would require the consent of PGE, Staff, the Citizens' Utility Board, and the Industrial Customer's of Northwest Utilities (see Order 03-535 adopting stipulations in Docket UE 149) and significant analytical work. The second alternative is being considered in Docket UE 165.

To remedy this mismatch in the 2005 RVM, Staff recommends that the Commission remove the $2.174 million in capacity payments from PGE's net variable power costs. Under this approach, shareholders would bear all of the costs and receive all of the benefits of these contracts during 2005. This has the effect of matching the 2005 costs and benefits. It also reflects the fact PGE has traditionally borne the risk of extreme price events between rate cases. Staff is willing to consider other remedies that PGE or intervenors may propose.

As you know, PGE files its final MONET run on November 10, 2004. We request a pre-hearing conference next week to further discuss this issue.

Sincerely,

David B. Hatton
Assistant Attorney General
Regulated Utility & Business Section

DBH:nal/GENK7978.DOC

cc: UE 161 Service List

CERTIFICATE OF SERVICE

I hereby certify that on the 5th day of November 2004, I served the foregoing LETTER upon the parties, hereto by the method indicated below:

GREG BASS SEMPRA ENERGY SOLUTIONS 101 ASH ST HQ08 SAN DIEGO CA 92101 gbass@semprasolutions.com	______ HAND DELIVER __X___ U.S. MAIL _____ OVERNIGHT MAIL _____ TELECOPY (FAX) __X___ ELECTRONIC MAIL (EMAIL)
JENNIFER CHAMBERLIN STRATEGIC ENERGY LLC 2633 WELLINGTON COURT CLYDE CA 94520 jchamberlin@sel.com	______ HAND DELIVER __X___ U.S. MAIL _____ OVERNIGHT MAIL _____ TELECOPY (FAX) __X___ ELECTRONIC MAIL (EMAIL)
J JEFFREY DUDLEY PORTLAND GENERAL ELECTRIC 121 SW SALMON ST 1WTC1301 PORTLAND OR 97204 jay_dudley@pgn.com	______ HAND DELIVER __X___ U.S. MAIL _____ OVERNIGHT MAIL _____ TELECOPY (FAX) __X___ ELECTRONIC MAIL (EMAIL)
JASON EISDORFER CITIZENS' UTILITY BOARD OF OREGON 610 SW BROADWAY STE 308 PORTLAND OR 97205 jason@oregoncub.org	______ HAND DELIVER __X___ U.S. MAIL _____ OVERNIGHT MAIL _____ TELECOPY (FAX) __X___ ELECTRONIC MAIL (EMAIL)
RANDALL J FALKENBERG RFI CONSULTING PMB 362 8351 ROSWELL RD ATLANTA GA 30350 consultrfi@aol.com	______ HAND DELIVER __X___ U.S. MAIL _____ OVERNIGHT MAIL _____ TELECOPY (FAX) __X___ ELECTRONIC MAIL (EMAIL)
ROCHELLE LESSNER LANE, POWELL, SPEARS, LUBERSKY LLP 601 SW 2ND AVE. STE. 2100 PORTLAND OR 97204 lessnerr@lanepowell.com	______ HAND DELIVER __X___ U.S. MAIL _____ OVERNIGHT MAIL _____ TELECOPY (FAX) __X___ ELECTRONIC MAIL (EMAIL)
KELLY M MORTON SEMPRA ENERGY SOLUTIONS 101 ASH ST HQ08 SAN DIEGO CA 92101 kmorton@sempra.com	______ HAND DELIVER __X___ U.S. MAIL _____ OVERNIGHT MAIL _____ TELECOPY (FAX) __X___ ELECTRONIC MAIL (EMAIL)

S BRADLEY VAN CLEVE DAVISON VAN CLEVE PC 1000 SW BROADWAY STE 2460 PORTLAND OR 97205 mail@dvclaw.com	______ HAND DELIVER __X___ U.S. MAIL _____ OVERNIGHT MAIL _____ TELECOPY (FAX) __X___ ELECTRONIC MAIL (EMAIL)
LORNE WHITTLES EPCOR MERCHANT & CAPITAL (US) INC 1161 W RIVER ST STE 250 BOISE ID 83702 lwhittles@epcor.ca	______ HAND DELIVER __X___ U.S. MAIL _____ OVERNIGHT MAIL _____ TELECOPY (FAX) __X___ ELECTRONIC MAIL (EMAIL)

____
David B. Hatton OSB #75151
Assistant Attorney General
1162 Court Street NE
Salem, Oregon 97301-4096
Telephone: (503) 378-6322
Attorney for the Public Utility Commission

PGE

Portland General Electric Company
Legal Department
121 SW Salmon Street • Portland, Oregon 97204
(503) 464-8926 • facsimile (503) 464-2200

Douglas C. Tingey
Assistant General Counsel

November 9, 2004

Traci Kirkpatrick
Administrative Law Judge
Oregon Public Utility Commission
P.O. Box 2148
Salem OR 97308-2148

Re: Docket No. UE 161 – Portland General Electric's 2005 Resource Valuation Mechanism

Dear Judge Kirkpatrick:

On November 5, 2004, counsel for Oregon Public Utility Commission Staff ("Staff") sent you a letter attempting to raise an issue regarding the ratemaking treatment of two capacity tolling agreements. That letter argued Staff's position on the issue, and this letter is sent to respond to that argument. In sum, as set forth below, Staff's letter is ill-timed and founded on a misunderstanding of capacity agreements and their Commission-approved ratemaking. Portland General Electric Company ("PGE") requests that Staff's request be summarily denied.

Capacity contracts have been included in every RVM proceeding. The Resource Valuation Mechanism ("RVM") was created and adopted by the Commission as part of a PGE general rate case, Docket No. UE 115, in 2001. At that time, as part of the implementation of Senate Bill 1149, the Oregon Public Utility Commission ("Commission") adopted the RVM proceeding to annually value and reset net variable power costs and determine the amount of any credit or charge for those customers opting for direct access. In creating the RVM process, PGE's costs were divided into two groups – net variable power costs that were included in the RVM update process, and fixed costs not included in the RVM process. PGE's power costs included two capacity contracts, one entered into in 1992 with Washington Water Power, and one entered into in 1995 with EWEB. Both of those capacity contracts were included in the RVM net variable power costs for ratemaking. Those capacity contracts were also included in RVM net variable power costs in the 2003 RVM proceeding (UE 139) and the 2004 RVM proceeding (UE 149). They are also included in net variable power costs in this 2005 RVM proceeding, and Staff has stipulated that the costs were proper and should be included in rates. Contrary to Staff's assertion, there is no issue as to the ratemaking treatment of capacity agreements in RVM proceedings.

The capacity contracts were entered into as part of the IRP process. In LC 33, the recently concluded PGE least cost planning docket, PGE's Integrated Resource Plan ("IRP") was subjected to intense scrutiny and numerous revisions over a two-plus year period. The need for capacity was included in that discussion starting with the August 2002 IRP filing. On July 20, 2004, the Commission issued an Order acknowledging PGE's Integrated Resource Final Action Plan. Ten action items were specifically acknowledged, including the following:

> 5. Acquire up to 50 MWa of baseload energy tolling in place of fixed price PPAs if required, *and 400 MW of tolling capability for peak purposes.* (Emphasis added.)

As part of the least cost planning procedure, PGE had issued a Request for Proposals ("RFP") seeking capacity tolling agreements. Staff was involved in and familiar with the results of that RFP. Consistent with the Commission's acknowledgment in LC 33, PGE entered into the two capacity tolling agreements that Staff questions here.

The two contracts are for a total of 400 MW, as called for by the acknowledged IRP. PGE has done exactly what its Commission-acknowledged least cost plan directed. The Commission itself said, in the LC 33 order that: "In ratemaking proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions that are consistent with acknowledged least-cost plans."

PGE acted timely and consistently with the Commission acknowledged Least Cost Plan, acquired these capacity resources in the manner directed by that plan, and included them in RVM net variable power costs like other capacity contracts. Notwithstanding this, Staff has asked the Commission to deny cost recovery for these contracts. Such a result would not be proper, fair, just or reasonable, or promote confidence in the regulatory process.

Capacity contracts are for reliability. Staff misconstrues or misunderstands the function and purpose of capacity agreements. PGE and other utilities enter into capacity agreements so they can reliably provide power to customers. Capacity contracts provide the right for the utility to receive, when needed, energy up to a specified amount. In those hours or days when there may not be sufficient resources in the region to meet all demands, having the ability to draw on capacity contracts helps to keep the lights on for PGE customers, even if there are blackouts elsewhere in the region due to insufficient energy. That is the reason PGE enters into capacity contracts.

Staff's theory that capacity contracts are for shareholder benefit is incorrect. They are for customer benefit in the form of reliable electric service. PGE customers expect, and deserve, reliable service, including during those times when energy resources may be short in the region. Capacity contracts are one necessary component of providing reliable service to customers. The costs of those capacity contracts are properly included in net variable power costs in the RVM, as they have been since the creation of the RVM process.

Staff's proposed remedy is inconsistent with its Stipulation in UE 149. In UE 149, PGE's 2004 RVM proceeding, all parties entered into a Stipulation settling all issues in the docket. That Stipulation was adopted and approved by the Commission in Order No. 03-535, issued August 29, 2003. In that Stipulation the parties agreed that, other than specifically identified enhancements, no party "will propose in the 2005 or 2006 RVM proceeding any enhancements to the Monet model used in the Final RVM Filing, unless the Monet model is modified through a general rate case or by the unanimous agreement of the Parties." In its letter Staff posits that one remedy to its perceived problem would be implementing expected net variable power cost modeling, an enhancement to Monet. Staff recognizes that implementing that change in this docket or in the 2006 RVM proceeding would require the consent of PGE, Staff, the Citizens' Utility Board, and the Industrial Customers of Northwest Utilities. Yet, Staff is attempting to indirectly and partially do what it has agreed not to do directly. Staff's real issue seems to be that they do not like the way capacity contracts are modeled by Monet. Staff's request is a backdoor attempt to undo the Stipulation in UE 149 and that request is inappropriate.

Conclusion. Staff has attempted, in the eleventh hour of this docket, to raise an issue that is well settled – the ratemaking treatment of capacity contracts. Capacity contracts have been included in net variable power costs since the RVM process was created. Staff's request is based on an erroneous view of the nature and purpose of capacity contracts. Staff's request is also inconsistent with its Stipulation in UE 149. These capacity contracts were entered into in conjunction with PGE's Least Cost Plan as acknowledged by the Commission. They are properly included in net variable power costs in this RVM.

The final RVM filing in this docket will be made very soon. From that filing customer rates will be set for next year, and the size of the credit for customers choosing direct access will be determined and posted on PGE's website on November 15, 2004. That process should not be stalled, or made uncertain, because of this last minute filing by Staff. Staff's request should be summarily denied. If, however, the Commission determines that further proceedings are necessary, PGE requests that a hearing be set, with the Commissioners present, the week of November 22, 2004, so that an order can be issued as soon thereafter as possible.

Sincerely,

DCT:am

cc: UE 161 Service List

ISSUED: November 16, 2004

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 161

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Adjustments to Schedule 125 (2005 RVM Filing).	)))))))	PREHEARING CONFERENCE MEMORANDUM

On November 5, 2004, Public Utility Commission of Oregon (Commission) Staff (Staff) requested a prehearing conference to discuss concerns about the ratemaking treatment of capacity tolling agreements raised upon review of Portland General Electric's (PGE) draft MONET run November 3, 2004. As PGE was scheduled to file a final MONET run on November 10, 2004, Staff requested that a prehearing conference be held as soon as possible. PGE filed a letter on November 9, 2004, opposing Staff's request for an investigation of capacity tolling agreement ratemaking.

On November 10, 2004, a prehearing conference was held in Salem, Oregon. Appearances were entered as follows: David B. Hatton, attorney, appeared on behalf of Commission Staff; Doug Tingey, attorney, appeared on behalf of Portland General Electric Company (PGE); Matthew Perkins, attorney, appeared by telephone on behalf of the Industrial Customers of Northwest Utilities (ICNU); Brad Van Cleve, attorney, also appeared by telephone on behalf of ICNU; and Bob Jenks, attorney, appeared by telephone on behalf of Citizens' Utility Board of Oregon (CUB).

After preliminary matters were addressed, conference participants went off the record to discuss how to proceed. Back on the record, Mr. Hatton represented that the conference participants agreed that no further action by the Commission was necessary in this docket and that the final MONET run would be filed as scheduled. Instead, parties agreed to work informally outside of a contested case proceeding to draft language regarding the modeling of capacity tolling agreements, with the intent to present such language in PGE's next general rate case filing. Should efforts be unsuccessful, however, Staff indicated it would consider filing a deferred accounting request with the Commission, prior to the end of this year, to address the capacity tolling agreements at issue for 2005.

Dated this 16th day of November, 2004, at Salem, Oregon.

Traci A. G. Kirkpatrick
Administrative Law Judge

UE-170/PacifiCorp
April 20, 2005
ICNU 17th Set Data Request 17.4

ICNU Data Request 17.4

Regarding PacifiCorp's response to OPUC DR No. 433d, please provide workpapers supporting the attachment provided and all other supporting documentation.

Response to ICNU Data Request 17.4

The Company's response to OPUC 433d contains a summary of account balances from the Company's accounting system; there are no additional workpapers.

UE-170/PacifiCorp
April 20, 2005
ICNU 17th Set Data Request 17.5

ICNU Data Request 17.5

Regarding PacifiCorp's response to OPUC DR No. 433d, please explain how there could be any fuel handling cost related to the GP-Camas contract.

Response to ICNU Data Request 17.5

The fuel handling costs are not related to the GP-Camas contract; they are from the Company's coal plants and should have been included in the filing. The Company identified the absence of the fuel handling costs at the same time it discovered the GP-Camas revenue error. These two adjustments nearly offset one another, which explains how both were overlooked in the process of preparing the Company's revenue requirement.

UE-170/PacifiCorp
April 20, 2005
ICNU 17th Set Data Request 17.7

ICNU Data Request 17.7

Regarding PacifiCorp's response to OPUC DR No. 433d, when did PacifiCorp discover the GP-Camas error?

Response to ICNU Data Request 17.7

The Company discovered the GP-Camas error while in the process of responding to OPUC Staff data request 433. The Company's net power cost reconciliation worksheet, Attachment OPUC 433d, was inadvertently not used when the filing was prepared. After completion of this reconciliation, the Company discovered an offsetting error, the absence of the fuel handling charges. Because the two errors were offsetting, they were overlooked during the preparation of the Company's revenue requirement. The Company intends to make these corrections as part of its rebuttal position along with any other errors discovered in the filing.

UE-032065/PacifiCorp
August 11, 2004
ICNU 13th Set Data Request 13.49

ICNU Data Request 13.49

Regarding the Rebuttal Testimony of M. Widmer:

Is it PacifiCorp's position that the modeling of the Hunter outage is intended to in some manner recover the costs of the outage that were previously not recovered, or is it to produce a reasonable projection of normalized power costs?

Response to ICNU Data Request 13.49

As described in Mr. Widmer's rebuttal testimony, the method allows for a four-year amortization (normalization) of outages while reducing variations in net power costs from year-to-year to smooth the customer impact.

Responder: Mark T. Widmer
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 170

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

DIRECT TESTIMONY OF

JAMES SELECKY

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

MAY 9, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. James T. Selecky, 1215 Fern Ridge Parkway, Suite 208, St. Louis, MO 63141-2000.

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. These are set forth in Exhibit ICNU/201.

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

A. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). The ICNU membership consists of industrial entities with facilities served by PacifiCorp (or the "Company").

Q. WHAT IS THE SUBJECT OF YOUR TESTIMONY?

A. My testimony will address the appropriate level of health care, pension and other retirement costs that should be included in the test year revenue requirement. In addition, I will be addressing the treatment of the Regional Transmission Organization ("RTO") expenses and the level of state and federal income taxes that should be included in PacifiCorp's revenue requirement. My testimony and that of the other ICNU witnesses address many, but not all, of the issues raised by the Company's filing. The fact that ICNU's witnesses have not addressed an issue should not be construed as an endorsement of PacifiCorp's position. In addition, ICNU may support or adopt issues and adjustments proposed by other parties.

The following table includes the adjustments sponsored by ICNU's witnesses Randall Falkenberg, Michael Gorman and myself:

TABLE 1

ICNU Proposed Adjustments on an Oregon Jurisdictional Basis
(000)

MSP QF Contracts	$7,669
MSP New Resources	$5,487
GRID Net Power Costs	$18,068
Return on Equity	$33,900
Health Care	$2,723
General Pension Expense	$3,446
IBEW 57 Pension Expense	$345
Post Retirement Benefit, Other Than Pension	$1,998
Consolidated Tax Adjustment	$27,580
RTO Expense	$900
Total ICNU Proposed Adjustments	**$102,116**

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My adjustments reduce PacifiCorp's total Company revenue requirement by approximately $136 million and the Oregon jurisdictional revenue requirements by approximately $37 million. My recommendations are as follows:

1. PacifiCorp's test year medical, dental and vision insurance costs are overstated. For purposes of this testimony, I will refer to the medical, dental and vision insurance costs as health care costs.

2. The Oregon Public Utility Commission ("OPUC" or the "Commission") should reject PacifiCorp's proposal to escalate medical costs at 12% and should escalate those costs at 8%, which represents current projections.

3. PacifiCorp's health care costs should be adjusted to reflect a larger contribution from employees. PacifiCorp indicates that in 2004, employee contributions were 9%, while industry data indicates that employee contributions are approximately 20%.

4. Escalating PacifiCorp's 2004 medical, dental and vision costs at rates of 8%, 5% and 5%, respectively, and reducing these costs for a greater employee contribution lowers the total Company expense by $11.85 million, and the Oregon jurisdictional expense by $2.605 million.

5. PacifiCorp has included in its test year revenue requirement an electric pension expense of $42.2 million on a total Company basis. This is significantly higher than its calendar year pension expenses in 2002 and 2003, which were $0.5 million and $14.8 million, respectively.

6. The Commission should establish PacifiCorp's pension expense utilizing its calendar year 2004 pension expense, which was $31.5 million, adjusted for a more reasonable discount rate.

7. Increasing PacifiCorp's pension expense discount rate from 6.25% to 6.75% produces a total Company electric pension expense of $27.2 million and a jurisdictional Oregon expense of $8.01 million.

8. PacifiCorp has included in its revenue requirement for IBEW 57 employees a pension expense contribution of $3 million. Since PacifiCorp has not made a contribution in 2005 and $3 million was the estimated contribution for 2005, the Commission should reduce PacifiCorp's IBEW 57 pension contribution expense for 2006 from $3 million to $1.5 million. This produces an Oregon jurisdictional expense of $442,000.

9. PacifiCorp's expense for post retirement benefits other than pension should be based on the 2004 level for this expense, and adjusted to reflect a higher discount rate.

10. Utilizing the 2004 post retirement benefit other than pension expense and adjusting that rate to reflect a 6.75% discount rate reduces the test year post retirement benefit and other pension expense from $26.8 million to $18.1 million.

11. PacifiCorp's rates in federal and state taxes that are included in its revenue requirement are overstated.

12. The Commission should recognize in PacifiCorp's ratemaking formula the income tax benefits associated with its parent company, PacifiCorp Holdings, Inc. ("PHI"). PHI filed a consolidated tax return, which allows it to utilize this debt to reduce its federal and state income tax obligations. Since approximately 95% of the assets of PHI are related to PacifiCorp, the benefit of the PHI debt should be passed on to PacifiCorp's ratepayers.

13. Reflecting this debt in the calculation of federal and state income taxes reduces PacifiCorp's Oregon jurisdictional revenue requirement by approximately $27.6 million.

14. PacifiCorp has included in its test year revenue requirement RTO costs of $3.057 million on a total Company basis. Since the RTO does not currently provide any benefits to Oregon ratepayers, these costs should be excluded from PacifiCorp's test year revenue requirement.

15. Excluding the RTO costs reduces the Oregon expense level by $900,410.

Q. WHAT IS THE IMPACT ON PACIFICORP'S OREGON REVENUE REQUIREMENT OF THE ADJUSTMENTS THAT YOU ARE PROPOSING?

A. Table 2 below summarizes the impact of my proposed adjustments on PacifiCorp's Oregon revenue requirement. I have provided the impact of my adjustments on a total Company and Oregon jurisdictional basis.

TABLE 2

Summary of Revenue Requirement Adjustments
(000)

Description	Total Company	Oregon Jurisdiction *
Health Care	$11,853	$2,723
Electric Pension Expense	$15,000	$3,446
IBEW 57	$1,500	$345
Post Retirement Benefit, Other Than Pension	$8,700	$1,998
Consolidated Tax Adjustment	$95,489	$27,580
RTO Expense	$3,057	$900
Total	$135,599	$36,991

* The Oregon jurisdictional revenue requirement reflects impacts on expense and capitalized costs.

I. HEALTH CARE COSTS

Q. WHAT LEVEL OF MEDICAL, DENTAL AND VISION BENEFITS ARE INCLUDED IN PACIFICORP'S REVENUE REQUIREMENT IN THIS CASE?

A. On a total Company basis, PacifiCorp has included the following medical, dental and vision insurance costs in its forecasted 2006 test year:

TABLE 3

Proposed Level of Health Care Benefits (Total Company)

Benefits	Amount ($Million)
Medical	$52.107
Dental	$4.026
Vision	$0.665
Total	$56.798

Q. HOW DOES THE 2006 PROPOSED LEVEL OF HEALTH CARE COSTS COMPARE WITH ACTUAL 2004 COSTS?

A. PacifiCorp is projecting a substantial increase in annual health care costs from actual 2004 costs to projected 2006 costs. In 2004, PacifiCorp's health care costs were $44.0 million. ICNU/202, Selecky/3. The forecasted 2006 health care costs are approximately 30% greater. The increase is, in part, attributable to an annual 12% increase in medical insurance costs and a 5% increase in dental and vision insurance costs.

Q. ARE PACIFICORP'S PROJECTED INCREASES IN HEALTH CARE COSTS REASONABLE?

A. No. PacifiCorp has stated in its testimony that the medical cost portion of its health care costs is expected to increase by 12% per year from 2004 to 2006. As shown in Table 3 above, the medical cost makes up approximately 92% of the health care costs. The assumed medical cost escalator of 12% exceeds the expected level of increase.

Q. WHAT IS THE BASIS FOR YOUR STATEMENT THAT 12% EXCEEDS THE EXPECTED LEVEL OF INCREASE?

A. Towers Perrin, a nationally recognized consulting firm that provides services in the area of employee benefits, stated in its November/December 2004 Monitor that employer health care costs are expected to rise by 8% in 2005. That publication states the following:

> According to the 2005 Towers Perrin Health Care Cost Survey, employers can expect, on average, an 8% increase in health care costs next year. That's a first significant break in the 5-year string of double digit increases that hammered employer-sponsored plans starting in 2000. Average increases reported during the period from 2000 to 2004 ranged from 12% to 16%.

Therefore, 12% annual increases projected by PacifiCorp are inconsistent with industry data and result in overstating health care costs.

Q. HAVE PACIFICORP'S HEALTH CARE COSTS HISTORICALLY EXCEEDED NATIONAL LEVELS?

A. No. A review of industry data indicates that average increases in health care costs from 2000 to 2004 have averaged 12% to 16% per year. However, a review of PacifiCorp's data indicates that during that period, PacifiCorp's medical care costs have increased by approximately 8.8% per year and the total health care costs have increased by approximately 8.3% per year. Since PacifiCorp's health care costs have escalated at a rate below the national average over the last couple of years, it is unreasonable to expect their health care costs should increase at a rate in excess of the forecasted rate. Therefore, the Commission should not utilize a 12% escalation rate to establish PacifiCorp's test year medical costs.

Q. ARE THERE FACTORS THAT SHOULD BE CONSIDERED IN ESTABLISHING THE APPROPRIATE LEVEL OF HEALTH CARE COSTS FOR PACIFICORP?

A. Yes. In the testimony of PacifiCorp witness Daniel J. Rosborough, he states that during 2004 the Company paid 91% of the total medical program costs and employees paid 9%. PPL/1100, Rosborough/10. Mr. Rosborough indicated that for 2005, the employees would be paying 10% of the costs of the plan. PPL/1100, Rosborough/10-11. These percentages of employee contribution are significantly below industry average.

Q. WHAT PERCENTAGE OF HEALTH CARE COSTS IN GENERAL ARE EMPLOYEES REQUIRED TO PAY?

A. Based on surveys conducted by Hewitt & Associates LLC and Towers Perrin, employees are picking up approximately 20% of health care costs. Towers Perrin Monitor states the following regarding the shifting of costs to employees:

> Not surprisingly, plan sponsors continue to shift more of the rising healthcare cost burden to employees. This year's survey shows the average employee share of premium costs will increase 14% in 2005, while the employer's share will increase by 7% in 2005. In addition, this year's survey respondents reported an average reduction in benefits of 2%.
>
> Despite the cost shifting, employers will pick up most of this year's cost increase and, overall, continue to shoulder the lion's share of the total. According to the survey, employees will contribute 19% of the premium costs for employee-only coverage, and 25% for the dependent coverage. Overall, they're picking up 21% leaving the remaining 79% to be paid by the employer.

Likewise, a survey performed by Hewitt & Associates LLC indicated that for 2003, the average employee would contribute 21% of the costs, and was projecting it would increase to 23% for 2004.

Q. WHAT IS YOUR PROPOSAL IN THIS CASE REGARDING THE APPROPRIATE LEVEL OF HEALTH CARE COSTS THAT SHOULD BE INCLUDED IN THE COMPANY'S REVENUE REQUIREMENT?

A. I have used PacifiCorp's actual 2004 health care costs as the starting point. This represents PacifiCorp's most recent known and measurable level of these costs. I then increased the health care costs using an annual rate of inflation of 8% for medical costs and 5% for dental and vision costs. I then adjusted the medical costs to reflect employee's contributions of 20% and not the 9% that is reflected in the 2004 actual data.

These adjustments reduce PacifiCorp's 2006 health care costs on a total Company basis from $56.8 million to $44.9 million. The details supporting this adjustment are shown in Exhibit ICNU/203.

Q. WHAT IS THE IMPACT ON PACIFICORP'S TEST YEAR EXPENSES OF YOUR PROPOSED ADJUSTMENT TO HEALTH CARE COSTS?

A. As Exhibit ICNU/203 shows, I have reduced the level of health care costs on a total Company basis by $11.853 million in 2006. Utilizing the Oregon System Overhead allocation factor of 29.446% and an expense allocation factor of 74.63%, PacifiCorp's Oregon health care expense included in its test year revenue requirement is reduced by $2.605 million.

Q. HAVE YOU MADE ANY ADJUSTMENT TO PACIFICORP'S HEALTH CARE COSTS TO REFLECT AN INCREASE IN EMPLOYEE LEVELS?

A. No. My adjustment is based on PacifiCorp's most recent known and measurable expense level escalated for inflationary pressures. As I indicated earlier, PacifiCorp has been able to keep its health care costs below national levels. My adjustment in this case is conservative because it reflects industry averages.

II. PENSION EXPENSES

Q. WHAT LEVEL OF PENSION EXPENSE HAS PACIFICORP INCLUDED IN ITS FORECASTED REVENUE REQUIREMENT FOR TEST YEAR 2006?

A. PacifiCorp projected a total Company electric pension expense of $42.2 million in calendar year 2006. As indicated in the testimony of PacifiCorp witness Rosborough, the 2006 projection is based on actual calendar year 2004 expense of $31.5 million, which is the result of an actuarial calculation conducted by the Company's actuary Hewitt & Associates. PPL/1100, Rosborough/4. It should be noted that for calendar years 2002 and 2003, PacifiCorp's pension expense was $0.5 million and $14.8 million, respectively. This data not only shows that the 2004 and the projected 2006 amounts represent a dramatic increase in pension expense, but also highlights the volatility of pension expense accrual.

Q. WHAT ARE THE REASONS THAT PACIFICORP GIVES FOR THIS DRAMATIC INCREASE IN ITS PENSION EXPENSE?

A. PacifiCorp provides the following reasons for its estimated pension expense for calendar year 2006:

1. From 2000 through 2002, the pension fund experienced $450 million of asset losses, which increased the level of its projected 2006 pension expense.

2. PacifiCorp claimed an investment return of 4% and 8% in 2004 and 2005, respectively.

3. The discount rate was lowered in 2004. This produced part of the increase from 2003 to 2004.

4. The Company is projecting an increase in the number of employees that will participate in its pension plan in fiscal year 2006 compared to fiscal year 2004.

These factors contributed to PacifiCorp's substantial increase in pension expense.

Q. WHAT ARE THE TWO KEY FACTORS THAT CAN INFLUENCE THE PROJECTED LEVEL OF PENSION EXPENSE?

A. Two key assumptions that can influence the level of pension expense are the discount rate utilized to present value the benefits and the expected return on pension fund assets.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE LEVEL OF PENSION EXPENSE THAT SHOULD BE INCLUDED IN PACIFICORP'S RATES?

A. My recommendation in this case is to utilize as a starting point PacifiCorp's calendar year 2004 pension expense of $31.5 million and adjust that for an appropriate discount rate.

As indicated in Exhibit ICNU/204, which is PacifiCorp's response to OPUC Staff DR No. 299, PacifiCorp's calendar year 2004 pension expense, which utilizes a measurement period from January 1, 2004 through December 31, 2004, is based on a discount rate of 6.25%. It is my recommendation that the amount of pension expense should be adjusted to reflect a higher discount rate. The pension expense is developed from an expected return on assets of 8.75%. This is the minimum rate that should be utilized.

Q. WOULD YOU DISCUSS WHY YOU BELIEVE IT IS APPROPRIATE TO ADJUST THE DISCOUNT RATE?

A. Yes. The discount rate that was utilized to calculate the calendar year 2004 pension expense is 6.25%. PacifiCorp indicated in its testimony that it was assuming that for 2006 the discount rate would be 6.75%, or 50 basis points higher. Increasing the discount rate reduces the pension expense accrual.

Also, PacifiCorp's witness Dr. Hadaway projects significant increases in the interest rates. Dr. Hadaway states in his testimony that ten-year Treasury notes and long-term Treasury bonds are expected to increase by 100 basis points or 1% from the September 2004 level through the fourth quarter of 2005. PPL/200, Hadaway/19. Dr. Hadaway also indicates that corporate bonds are projected to increase by 80 basis points or 0.8% over the same period of time. PPL/200, Hadaway/19. Since the discount rate represents an interest rate, increasing the discount rate by only 50 basis points is justifiable.

Q. COULD YOU PLEASE BRIEFLY DESCRIBE HOW YOU DETERMINE THE IMPACT ON PACIFICORP'S PENSION EXPENSE OF INCREASING THE DISCOUNT RATE FROM 6.25% TO 6.75%?

A. In response to OPUC Staff DR No. 22, PacifiCorp indicated that an increase in the discount rate from 6.25% to 6.75% reduced the 2006 pension expense from $48.9 million to $42.2 million, or approximately 13.7%. ICNU/205. Therefore, I adjusted the 2004 pension expense of $31.5 million by 13.7% to reflect the utilization of a higher discount rate. This reduced the total Company electric pension expense by $4.3 million and $1.27 million on an Oregon jurisdictional basis.

Q. WHAT LEVEL OF RETURN ON EXPECTED ASSETS SHOULD BE UTILIZED TO DETERMINE PACIFICORP'S TEST YEAR PENSION EXPENSE?

A. An expected return on assets of 8.75% should be utilized to determine PacifiCorp's pension expense. As previously indicated, the 2004 pension expense uses an 8.75% return on expected assets.

Table 4 below shows the type of investment and the return that PacifiCorp expects to receive from those investments. As shown, its expected return is approximately 8.75%.

TABLE 4

Expected Return on Pension Assets

Type of Investment	Weighting	Expected Return	Weighted Cost
Domestic Stocks	55%	9%	5.06%
Bonds	35%	7%	2.28%
Private Holdings	10%	14%	1.40%
Total Return			8.74%

Q. ARE THERE ANY OTHER FACTORS THAT SHOULD BE CONSIDERED THAT SUPPORT USING AN EXPECTED RETURN ON ASSETS OF 8.75%?

A. Yes. In response to ICNU DR No. 15.2, PacifiCorp provided its most recent audit of PacifiCorp's Retirement Plan. ICNU/206. The audit addressed 2002 and 2003. A review of that audit indicates that PacifiCorp has made considerable investments in limited partnership units that are more risky. These investments have incurred significant losses from their cost basis. The losses from the cost basis are approximately $40 million. ICNU/206, Selecky/33. These more risky investments make up approximately 11% of the total current value investments as reported in the audit. Since these investments are more risky, a higher return is warranted and a higher return should be required from these investments. Therefore, it is appropriate to reflect a higher return rate in the development of PacifiCorp's pension expense. This is captured in the return associated with "Private Holdings."

Q. WHY ARE YOU ADDRESSING THE EXPECTED RATE OF RETURN THAT WAS UTILIZED TO CALCULATE THE 2004 PENSION COSTS?

A. A review of the testimony of PacifiCorp witness Rosborough indicates that the projected asset returns utilized to calculate PacifiCorp's test year pension expense are less than 8.75%. Mr. Rosborough's testimony states that an assumed investment return of 4% and 8% were utilized in 2004 and 2005, respectively. PPL/1100, Rosborough/5. Therefore, PacifiCorp's 2006 projection does not reflect the 8.75% return on assets. It should also be noted that for 2004 the actual return on pension assets was 10.5%.

Q. WHAT IS THE TOTAL ADJUSTMENT YOU ARE PROPOSING TO PACIFICORP'S PENSION EXPENSE?

A. I am proposing that PacifiCorp's total Company electric pension expense be reduced from the projected $42.2 million contained in the rate case to $27.2 million. As previously discussed, this level of pension expense reflects PacifiCorp's 2004 pension expense and reflects adjustments for a higher discount rate.

III. IBEW PENSION EXPENSES

Q. DOES YOUR PENSION EXPENSE ADJUSTMENT REFLECT THE PENSION EXPENSE FOR ALL PACIFICORP EMPLOYEES?

A. No. PacifiCorp has an agreement with IBEW 57 that requires PacifiCorp to make annual contributions to IBEW 57's pension fund. For purposes of this rate case, PacifiCorp forecasted that it would make contributions to IBEW's pension fund of $3 million in both 2005 and 2006.

Q. DID PACIFICORP MAKE A $3 MILLION CONTRIBUTION TO THE IBEW PENSION FUND IN 2005?

A. No. In response to ICNU DR No. 19.4, the Company indicated that it did not make a contribution to the IBEW 57 pension expense in 2005. ICNU/207. This was a result of negotiations with representatives of IBEW 57.

Q. SHOULD THE COMMISSION MAKE ANY ADJUSTMENT TO THE IBEW 57 PENSION EXPENSE THAT IS INCLUDED IN ITS TEST YEAR?

A. Yes. PacifiCorp has included in its revenue requirement a $3 million contribution to IBEW pension expense in its 2006 test year. Since there was no contribution in 2005, I recommend that the Commission reduce the test year pension expense by 50%. That is, for ratemaking purposes, the Commission should recognize only $1.5 million of IBEW 57 pension expense.

Q. WHAT IS THE IMPACT ON PACIFICORP'S REVENUE REQUIREMENT EXCLUDING $1.5 MILLION OF IBEW 57 PENSION EXPENSE?

A. Excluding $1.5 million of IBEW's 57 pension expense from PacifiCorp's test year revenue requirement reduces its Oregon expenses by $330,000.

Q. WHAT IS THE TOTAL IBEW 57 ADJUSTMENT YOU ARE PROPOSING TO PACIFICORP'S PENSION EXPENSE?

A. I am proposing to reduce the pension expense associated with PacifiCorp's contribution to IBEW 57. This adjustment reduces the total pension expense by $1.5 million. As a result of these adjustments, PacifiCorp's total Company pension expense is reduced by $16.5 million and $3.625 million on an Oregon jurisdictional basis.

IV. POST RETIREMENT BENEFITS OTHER THAN PENSION

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE LEVEL OF FAS 106 COSTS (POST RETIREMENT BENEFITS OTHER THAN PENSION)?

A. Yes. The adjustment I made to FAS 106 expense is similar to the adjustment I made to pension expense. That is, as a starting point I utilized the actual calendar year 2004 FAS 106 expense as provided in PacifiCorp's response to OPUC DR No. 299. ICNU/204. I then adjusted this expense to reflect a discount rate of 6.75%. PacifiCorp indicated that the 2004 FAS 106 was calculated using a discount rate of 6.25%. The reasons for adjusting the discount rate for FAS 106 are the same reasons that I outlined above in my testimony regarding pensions.

Q. WHAT IS THE IMPACT OF YOUR PROPOSED FAS 106 ADJUSTMENTS?

A. The impact of my FAS 106 adjustments is to reduce PacifiCorp's proposed expense of $26.8 million to $18.1 million. On a jurisdictional basis, this adjustment reduces PacifiCorp's FAS 106 expense by $1.912 million. The pension and other post-retirement cost adjustments are shown on Exhibit ICNU/208.

V. CONSOLIDATED TAX ADJUSTMENT

Q. WOULD YOU PLEASE DESCRIBE THE INCOME TAX ISSUE?

A. PacifiCorp is a wholly owned subsidiary of PacifiCorp Holdings Inc. ("PHI") which is a non-operating, direct, wholly owned subsidiary of the U.K. utility holding company ScottishPower. The PHI corporate structure was designed by ScottishPower, to minimize income taxes on the taxable income of PacifiCorp and other PHI affiliates. PHI was capitalized by ScottishPower by an intercompany acquisition related loan between ScottishPower and PHI. PHI then used this loan to acquire ScottishPower shares of PacifiCorp. PHI pays interest on the acquisition loan, and deducts the interest on its income tax filings. The deduction of the interest on the acquisition loan results in a significant income tax deduction that allows PHI to avoid or significantly reduce the amount of state and federal income taxes paid on the profits generated from PacifiCorp regulated utility operations.

Q. DOES PACIFICORP RECOGNIZE THE PHI DEBT AND THE PHI INTEREST DEDUCTION WHEN CALCULATING ITS INCOME TAXES TO INCLUDE IN ITS OREGON REVENUE REQUIREMENT?

A. No. It calculates state and federal income taxes for PacifiCorp without regard to the tax deductibility of the PHI acquisition debt interest. This acquisition debt interest reduces PHI actual tax obligations and enhances PHI after tax earnings. As a result, PacifiCorp has included tax expense in its revenue requirement that will not be paid to the taxing authority. In other words, rates have been increased to cover income taxes that will never be paid.

Q. HOW LARGE OF A TAX BENEFIT IS PRODUCED BY THE PHI DEBT?

A. A Standard & Poor's research report on PacifiCorp, which was provided in PacifiCorp's response to OPUC Staff DR No. 80, states that at March 31, 2004, PHI's balance sheet contained acquisition-related debt of $2.375 billion bearing an interest rate of 6.75%. ICNU/402, Gorman/12. Assuming a composite state and federal tax rate of 37.95% produces tax benefit of approximately $61 million per year. Assuming that the loan supported only regulated activities would reduce PacifiCorp's revenue requirement by approximately $98 million.

Q. SHOULD THE PHI ACQUISITION-RELATED DEBT BE CONSIDERED IN DETERMINING PACIFICORP'S RETAIL REVENUE REQUIREMENT?

A. Yes. By not recognizing the interest deductibility of the PHI loan, this Commission would be asking Oregon ratepayers to pay taxes that neither PacifiCorp nor ScottishPower are required to pay. The income taxes as contained in this filing ignore the existence of this tax benefit. It should be remembered that PacifiCorp's regulated ratepayers are largely supporting this loan.

Q. HAVE YOU ESTIMATED THE IMPACT THAT THIS BENEFIT HAS ON PACIFICORP'S OREGON OPERATION?

A. Yes. As noted above, PHI's loan is $2.375 billion and bears an interest rate of 6.75%. This produces annual tax deductible interest expense of $160.31 million.

In response to ICNU Data Request No. 16.19, PacifiCorp provided the amount of buildings and other depreciable assets, land and other accumulated depreciation as of March 31, 2004, as listed on its consolidated PHI tax return. ICNU/209. Based on that summary, regulated utility operations are entitled to 94.72% of the tax benefit. The Oregon jurisdictional rate base for 2006 is 28.88% of the total Company rate base. Therefore, jurisdictional Oregon customers should be allocated 28.88% of the interest expense for tax purposes. This produces approximately $43.86 million of additional tax deductions which should be reflected in Oregon's jurisdictional revenue requirement.

Q. WHAT IS THE IMPACT ON THE OREGON REVENUE REQUIREMENT OF RECOGNIZING THE DEDUCTIBILITY OF $43.7 MILLION OF ADDITIONAL INTEREST EXPENSE?

A. Utilizing an Oregon composite tax rate of 37.95%, recognizing an additional $43.7 million of interest expense reduces Oregon's tax by $16.64 million and its revenue requirement by $27.58 million.

Q. BY PROPOSING THIS ADJUSTMENT ARE YOU RECOGNIZING ANY TAX LOSSES ASSOCIATED WITH ANY OF PHI'S NON-REGULATED SUBSIDIARIES?

A. No. My recommendation is based on PHI tax minimization structure, which is created by the financing structure that PHI currently has in place for financing its regulated operations. The adjustment does not take into account the profits or losses or credits that result from its operations of its unregulated subsidiaries. This adjustment should not be confused with reflecting the profitability of non-regulated assets in the regulated ratemaking formula.

VI. RTO DEVELOPMENT COSTS

Q. HAS PACIFICORP INCLUDED ANY RTO DEVELOPMENT COSTS IN ITS TEST YEAR REVENUE REQUIREMENT?

A. Yes. On a total Company basis, PacifiCorp has included $3.057 million of RTO costs in its test year revenue requirement. This number was provided in response to ICNU DR No. 19.3. ICNU/210. Although this cost is identified as a fiscal year 2006 cost, I have assumed it is the cost included in the test year revenue requirement.

Q. DO THE RTO EXPENSES PROVIDE BENEFITS TO THE RATEPAYERS?

A. No. Currently the RTO is not operating and is not expected to be operating during the test year. As a result, the expenses associated with the development of the RTO are neither used nor useful during the test year. As a result, these costs should not be passed on to ratepayers on a current basis.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE TREATMENT OF THE RTO EXPENSES?

A. Because this expense is not providing a current benefit to ratepayers, recovery of these costs should not occur until the RTO is operating. Therefore, the $3.057 million of RTO expenses on a total Company basis should be excluded from PacifiCorp's test year revenue requirement.

Q. WHAT IS THE IMPACT ON PACIFICORP'S OREGON EXPENSES AS A RESULT OF EXCLUDING THE RTO EXPENSES?

A. Excluding the RTO expenses reduces PacifiCorp's revenue requirement by $900,410. It is my recommendation that these costs should be deferred and subject to a prudency review once the RTO is operating and providing benefits to PacifiCorp's Oregon ratepayers.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Qualifications of James T. Selecky

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. James T. Selecky. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141.

Q. PLEASE STATE YOUR OCCUPATION.

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

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A. I graduated from Oakland University in 1969 with a Bachelor of Science degree with a major in Engineering. In 1978, I received the degree of Master of Business Administration with a major in Finance from Wayne State University.

I was employed by The Detroit Edison Company ("DECo") in April of 1969 in its Professional Development Program. My initial assignments were in the engineering and operations divisions where my responsibilities included evaluation of equipment for use on the distribution and transmission system; equipment performance testing under field and laboratory conditions; and troubleshooting and equipment testing at various power plants throughout the DECo system. I also worked on system design and planning for system expansion.

In May of 1975, I transferred to the Rate and Revenue Requirement area of DECo. From that time, and until my departure from DECo in June 1984, I held various positions which included economic analyst, senior financial analyst, supervisor of the Rate Research Division, supervisor of the Cost-of-Service Division and director of the

Revenue Requirement Department. In these positions, I was responsible for overseeing and performing economic and financial studies and book depreciation studies; developing fixed charge rates and parameters and procedures used in economic studies; providing a financial analysis consulting service to all areas of DEC; developing and designing rate structure for electrical and steam service; analyzing profitability of various classes of service and recommending changes therein; determining fuel and purchased power adjustments; and all aspects of determining revenue requirements for ratemaking purposes.

In June of 1984, I joined the firm of Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995 the firm of BAI was formed. It includes most of the former DBA principals and staff. At DBA and BAI I have testified in electric, gas and water proceedings involving almost all aspects of regulation. I have also performed economic analyses for clients related to energy cost issues.

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

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?

A. Yes. I have testified on behalf of DECo in its steam heating and main electric cases. In these cases I have testified to rate base, income statement adjustments, changes in book depreciation rates, rate design, and interim and final revenue deficiencies.

In addition, I have testified before the regulatory commissions of the States of Colorado, Connecticut, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Maryland, Massachusetts, Missouri, New Hampshire, New Jersey, North Carolina, Ohio, Oklahoma, Tennessee, Texas, Utah, Washington, Wisconsin, and Wyoming, and the Provinces of

Alberta and Saskatchewan. I also have testified before the Federal Energy Regulatory Commission. In addition, I have filed testimony in proceedings before the regulatory commissions in the States of Florida, Montana, New York, and Pennsylvania and the Province of British Columbia. My testimony has addressed revenue requirement issues, cost of service, rate design, financial integrity, accounting-related issues, merger-related issues, and performance standards. The revenue requirement testimony has addressed book depreciation rates, decommissioning expense, O&M expense levels, and rate base adjustments for items such as plant held for future use, working capital, and post test year adjustments. In addition, I have testified on deregulation issues such as stranded cost estimates and rate design.

Q. ARE YOU A REGISTERED PROFESSIONAL ENGINEER?

A. Yes, I am a registered professional engineer in the State of Michigan.

PACIFICORP – OREGON

Health Care Adjustment
(000)

Line	Description	Medical	Dental	Vision	Total
1	Inflation Projection	8%	5%	5%	
2	2004	$40,854	$2,655	$495	$44,005
3	2005	$44,123	$2,788	$520	$47,431
4	2006	$47,652	$2,927	$546	$51,126
5	Adj. for Emp. Contribution	$41,892	$2,573	$480	$44,946
6	2006 PacifiCorp Forecast	$52,107	$4,026	$665	$56,799
7	Total Company Adjustment	$10,215	$1,453	$185	$11,853
8	Oregon Allocation	29.446%	29.446%	29.446%	29.446%
9	Oregon Adjustment	$3,008	$428	$54	$3,490
10	Expense Factor				74.63%
11	Expense Adjustment				$2,605

PACIFICORP – OREGON

Pension and Other Post Retirement Expense

Line	Description	Amount (000)	Amount (000)
1	2004 Pension Expense	$31,200	
2	Discount Rate Adjustment	$4,300	
3	Test Year Pension Expense		$27,200
4	IBEW Pension Contribution		$1,500
5	2004 OPEB Expense	$21,000	
6	Discount Rate Adjustment	$2,900	
7	Test Year OPEB Expense		$18,100
8	Total		$46,800
9	PacifiCorp's Test Year Pension Expense	$42,200	
10	IBEW Pension Contribution	$3,000	
11	OPEB Expense	$26,800	
12	Total		$72,000
13	Reduction from Company		$25,200
14	Oregon System Overhead Allocation (Line 13 X 29.446%)		$7,420
15	Expense Reduction (Line 14 X 74.63%)		$5,538

UE-170/PacifiCorp
January 12, 2005
OPUC Data Request 188

OPUC Data Request 188

For the Benefits listed on page 27 of Section 4.18 of PPL Exhibit 801, please provide the actual calendar years 2002, 2003 and 2004 costs.

Response to OPUC Data Request 188

The requested information is provided as Attachment OPUC 188.

OREGON

2004 GENERAL RATE CASE

UE-170

PACIFICORP

OPUC STAFF DATA REQUEST

ATTACHMENT OPUC 188

CE	CE Name	CY 2002	CY 2003	CY 2004
501125	Medical	34,524,812	37,798,363	40,854,270
501175	Dental	2,819,623	3,409,592	2,655,000
501200	Vision	176,378	373,291	495,466
501225	Life	(1,054,184)	765,693	293,475
501250	Stock/401(k)/ESOP	16,144,495	17,293,145	17,221,858
501251	401(k) Admin	379,250	1,022,363	1,201,184
501275	AD&Disab	56,881	159,572	17,982
501300	L-Term Disab	1,921,553	1,681,004	1,964,129
501325	Physical Exams	473	1,372	925
501650	Worker's Comp	3,118,136	449,096	428,318
501670	Black Lung Benefit	144	109	11,965
502300	Education Assist	370,022	380,992	396,413
502900	Oth Salary Overhd	1,249,551	1,743,673	413,882
	Total	**59,707,134**	**65,078,265**	**65,954,866**

PACIFICORP – OREGON

Health Care Adjustment
(000)

Line	Description	Medical	Dental	Vision	Total
1	Inflation Projection	8%	5%	5%	
2	2004	$40,854	$2,655	$495	$44,005
3	2005	$44,123	$2,788	$520	$47,431
4	2006	$47,652	$2,927	$546	$51,126
5	Adj. for Emp. Contribution	$41,892	$2,573	$480	$44,946
6	2006 PacifiCorp Forecast	$52,107	$4,026	$665	$56,799
7	Total Company Adjustment	$10,215	$1,453	$185	$11,853
8	Oregon Allocation	29.446%	29.446%	29.446%	29.446%
9	Oregon Adjustment	$3,008	$428	$54	$3,490
10	Expense Factor				74.63%
11	Expense Adjustment				$2,605

UE-170/PacifiCorp
February 3, 2005
OPUC Data Request 299

OPUC Data Request 299

Per PacifiCorp's response to Staff Data Request 235 and in the format provided in PacifiCorp's SEC Forms (i.e. 10-K, 10-Q), please provide the Net periodic benefit cost (income) from the time period of January 1, 2004 through December 31, 2004. The response should include:

a. Service Cost (please footnote any contributions to the PacifiCorp/IBEW Local 57 Retirement Trust Fund)
b. Interest Cost
c. Expected return on plan assets
d. Amortization of unrecognized net obligation
e. Amortization of unrecognized prior service cost
f. Amortization of unrecognized gain

Response to OPUC Data Request 299

The requested information is provided in Attachment OPUC 299. In addition, a cash contribution was made to the PacifiCorp/IBEW Local 57 Retirement Trust Fund in February 2004 in the amount of $5,644,291.

OREGON

2004 GENERAL RATE CASE

UE-170

PACIFICORP

OPUC STAFF DATA REQUEST

ATTACHMENT OPUC 299

Hewitt

Hewitt Associates LLC
100 Bayview Circle
Newport Beach, CA 92660-2935
P.O. Box 6300
Newport Beach, CA 92658-6300
Tel (949) 725-4500
Fax (949) 725-0668
www.hewitt.com

January 31, 2005

Mr. Daniel J. Rosborough
PacifiCorp
825 NE Multnomah Suite 1800 LH
Portland, OR 97232

Dear Dan:

Subject: FY 2005 FAS 87 and FAS 106 Expense for Electric Operations

The final FY 2005 (measurement period January 1, 2004 through December 31, 2004) expense for Electric Operations under the PacifiCorp Retirement Plan and the postretirement benefit plans of PacifiCorp are as follows:

	PacifiCorp Retirement Plan	Postretirement Benefit Plans
Service cost	$21.6	$6.7
Interest cost	68.0	25.4
Expected return on assets	(74.9)	(21.6)
Amortizations:		
Unrecognized net obligation	8.4	10.0
Unrecognized prior service costs	0.8	0.0
Unrecognized net loss	7.6	0.5
Net periodic benefit cost	$31.5	$21.0

The amounts above are based on a discount rate of 6.25%, a selected by PacifiCorp as of December 31, 2003.

Sincerely,

Hewitt Associates LLC

Daniel S. Watts

DSW:hs

UE-170/PacifiCorp
December 15, 2004
OPUC Data Request 22

OPUC Data Request 22

Per PPL/1102, Rosborough/1, please provide revised calculations for calendar year 2005 and 2006 pension expenses for a:

- 1 percent change (both directions) in the rate of return on market value of assets during 2004 and 2005; and
- .5 percent change in the discount rate (both directions).

Response to OPUC Data Request 22

The requested information is provided as Attachment OPUC Data Request 22.

OREGON

2004 GENERAL RATE CASE

UE-170

PACIFICORP

OPUC STAFF DATA REQUEST

ATTACHMENT OPUC 22

Attachment OPUC Data Request 22

PacifiCorp Electric Operations
Impact of Different Assumptions on Projected Pension Expense ($ million)

Expected Return on Assets (ERA)

ERA	CY 2005	CY 2006
7.75%	49.7	50.0
8.75%	41.6	42.2
9.75%	33.5	34.4

Discount Rate

CY 2005		CY 2006	
Discount Rate	Expense	Discount Rate	Expense
6.00%	48.5 *	6.25%	48.9
6.50%	41.6	6.75%	42.2
7.00%	N/A **	7.25%	34.7

* It is expected that the final discount rate for CY 2005 will be 6.00%

** Calculation not performed because current interest rates would not support a 7.00% discount rate

UE-170/PacifiCorp
April 14, 2005
ICNU 15th Set Data Request 15.2

ICNU Data Request 15.2

Please provide a copy of the audit of the most recent pension actuarial study.

Response to ICNU Data Request 15.2

Please see Attachment ICNU 15.2 on the enclosed CD.

OREGON

2004 GENERAL RATE CASE

UE-170

PACIFICORP

ICNU 15th SET DATA REQUESTS

ATTACHMENT ICNU 15.2

ON THE ENCLOSED CD

PRICEWATERHOUSECOOPERS

PacifiCorp Retirement Plan
Financial Statements
December 31, 2003 and 2002

PacifiCorp Retirement Plan
Index
December 31, 2003 and 2002

Page(s)

Note: Other schedules required by 29 CFR 2520.103-10 of the Department of Labor's Rules and Regulations for Reporting and Disclosure under the Employee Retirement Income Security Act ("ERISA") of 1974 have been omitted because they are not applicable.

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
1300 SW Fifth Avenue
Suite 3100
Portland OR 97201
Telephone (971) 544 4000
Facsimile (971) 544 4100

Report of Independent Auditors

To the Participants and Administrator of the
PacifiCorp Retirement Plan

We were engaged to audit the financial statements and supplemental schedules of the PacifiCorp Retirement Plan (the "Plan") at December 31, 2003 and 2002 and for the years then ended, as listed in the accompanying index. These financial statements and schedules are the responsibility of the Plan's management.

As permitted by 29 CFR 2520.103-8 of the Department of Labor's Rules and Regulations for Reporting and Disclosure under the Employee Retirement Income Security Act of 1974, the plan administrator instructed us not to perform, and we did not perform, any auditing procedures with respect to the information summarized in Note 5, which was certified by State Street Bank & Trust Company and Deutsche Bank Trust Company Americas, the trustees of the Plan, except for comparing such information with the related information included in the financial statements and supplemental schedules. We have been informed by the plan administrator that the trustees hold the Plan's investment assets and execute investment transactions. The plan administrator has obtained certifications from the trustees as of December 31, 2003 and 2002 and for the years then ended, that the information provided to the plan administrator by the trustees is complete and accurate.

Because of the significance of the information that we did not audit, we are unable to, and do not, express an opinion on the accompanying financial statements and supplemental schedules taken as a whole. The form and content of the information included in the financial statements and schedules, other than that derived from the information certified by the trustees, have been audited by us in accordance with auditing standards generally accepted in the United States of America and, in our opinion, are presented in compliance with the Department of Labor's Rules and Regulations for Reporting and Disclosure under the Employee Retirement Income Security Act of 1974.

As described in Note 14, the Plan's financial statements as of and for the year ended December 31, 2002 have been restated.

PricewaterhouseCoopers LLP

Portland, Oregon
January 14, 2005

PacifiCorp Retirement Plan
Statements of Net Assets Available for Pension Benefits
December 31, 2003 and 2002

	2003	2002 (Restated)
Assets		
Investments, at fair value (Notes 2 and 6):		
Short-term investments	$ 16,988,351	$ 10,247,703
U.S. government securities (includes securities loaned of $19,603,399 and $21,871,865)	115,382,186	94,706,110
Corporate bonds (includes securities loaned of $2,821,740 and $3,097,219)	50,360,030	57,754,878
Common stock (includes securities loaned of $9,709,171 and $19,734,794)	275,889,623	221,155,513
Mutual funds	197,920,102	208,064,682
Investment of securities lending collateral, at cost and market value (Note 7)	33,067,927	44,250,385
Limited partnership units	81,736,302	81,755,409
Other investments	-	734,027
Total investments	771,344,521	718,668,707
Net assets held in 401(h) account (Note 3)	59,571,733	49,236,183
Receivables:		
Employer contribution receivable	61,555,151	33,448,581
Interest and dividends	2,527,590	2,714,269
Due from brokers for securities sold	2,982,485	2,733,187
Total receivables	67,065,226	38,896,037
Unrealized appreciation on forward foreign currency exchange contracts (Note 8)	1,376,822	-
Total assets	899,358,302	806,800,927
Liabilities		
Payables:		
Payables due to brokers for securities purchased	4,543,347	2,021,757
Payable for securities lending collateral (Note 7)	33,067,927	44,250,385
Amounts related to obligation of 401(h) account	59,571,733	49,236,183
Total payables	97,183,007	95,508,325
Unrealized depreciation on forward foreign currency exchange contracts (Note 8)	1,529,337	-
Total liabilities	98,712,344	95,508,325
Net assets available for pension benefits	$ 800,645,958	$ 711,292,602

The accompanying notes are an integral part of the financial statements.

PacifiCorp Retirement Plan
Statements of Changes in Net Assets Available for Pension Benefits
Years Ended December 31, 2003 and 2002

	2003	2002 (Restated)
Investment income (loss):		
Net appreciation (depreciation) in fair value of investments (Note 6)	$ 127,244,022	$ (69,386,463)
Interest	7,145,879	11,856,591
Dividends	6,331,082	6,101,218
Income on pooled funds	508,888	1,032,834
Securities lending income (Note 7)	76,067	85,148
Foreign currency transactions	(337,547)	(2,432,089)
	140,968,391	(52,742,761)
Less investment expenses	2,168,823	2,879,067
	138,799,568	(55,621,828)
Employer contributions	61,555,151	33,448,581
Total additions (reductions)	200,354,719	(22,173,247)
Benefits paid	107,794,803	111,383,354
Transfer to WSCC Retirement Trust (Note 11)	-	2,047,400
Administrative expenses	1,490,442	1,444,963
PBGC premiums paid	1,716,118	1,416,962
Total deductions	111,001,363	116,292,679
Net increase (decrease)	89,353,356	(138,465,926)
Net assets available for pension benefits:		
Beginning of year	711,292,602	849,758,528
End of year	$ 800,645,958	$ 711,292,602

The accompanying notes are an integral part of the financial statements.

PacifiCorp Retirement Plan
Statement of Accumulated Plan Benefits
January 1, 2003

Actuarial present value of accumulated Plan benefits	
Vested benefits	
Participants currently receiving payments	$ 594,872,666
Other participants	276,993,045
Total vested benefits	871,865,711
Nonvested benefits	15,722,028
Total actuarial present value of accumulated Plan benefits	$ 887,587,739

The accompanying notes are an integral part of the financial statements.

PacifiCorp Retirement Plan
Statement of Changes in Accumulated Plan Benefits
Year Ended January 1, 2003

Actuarial present value of accumulated Plan benefits at beginning of year	$ 893,189,773
Increase (decrease) applicable to	
Plan experience, including population changes	(66,874)
Additional benefit accrual	17,646,371
Interest	68,263,260
Benefits paid	(111,383,354)
Change in Plan provisions (Note 11)	19,938,563
Net decrease	(5,602,034)
Actuarial present value of accumulated Plan benefits at end of year	$ 887,587,739

The accompanying notes are an integral part of the financial statements.

1. Description of Plan

The following description of the PacifiCorp Retirement Plan (the "Plan") is provided for general information purposes only. Participants should refer to the Plan document for more complete information.

General

The Plan is a noncontributory, defined benefit pension plan and includes a medical benefits component (Note 3) in addition to normal retirement benefits (see below). The Plan covers substantially all employees of PacifiCorp and certain subsidiaries (the "Company"), except those employees who are covered by collective bargaining agreements, which do not provide for their participation in the Plan, employees who have not completed one year of service, and employees who have not attained the age of 21. The Plan is subject to the provisions of the Employee Retirement Income Security Act of 1974 ("ERISA").

Pension Benefits

The Plan provides for normal retirement upon reaching age 65 and for early retirement at ages 55 through 64 with five years of service, or if the participants age plus years of service total at least 75. Benefits are 100% vested after five years of service, as defined by the Plan. The basic benefit on normal retirement is an annual pension payable for the life of the participant equal to 1.3% times the participant's final average pay, plus 0.65% times the final average pay in excess of the Social Security covered compensation, multiplied by years of credited service (up to 30 years), plus 0.25% of final average pay for each year of credited service in excess of 30 years. Other minimum benefits may apply.

Death and Disability Benefits

A benefit shall be payable to a surviving spouse upon the death of a participant based on provisions contained in the Plan document. A participant who becomes disabled while employed by a participating company shall continue to accrue service under the Plan depending on the extent of the disability, years of service and other provisions contained in the Plan document.

Deferred Compensation Benefits

The Plan was amended in 1992 to incorporate the liabilities previously accrued in the Utah Power & Light Company Deferred Compensation Plan ("DCP"). The DCP entitled participants, or their surviving spouse, to defined monthly benefits, or alternative forms of settlements as permitted by the DCP, based upon their highest attained rate of pay while a participant. The DCP participants can elect early retirement between the ages of 55 and 65 at reduced levels of benefits.

2. Summary of Accounting Policies

Basis of Accounting

The accompanying financial statements are prepared using the accrual method of accounting.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect reported amounts of assets, liabilities and changes therein, and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of income, deposits and withdrawals during the reporting period. Actual results could differ from those estimates.

Investment Valuation and Income Recognition

The Plan's investments are stated at fair value. If available, quoted market prices are used to value investments. Short-term investments consist primarily of cash and cash equivalents, which are valued at cost, using the end-of-period exchange rates for foreign currencies. U.S. government securities, corporate bonds and common stocks are valued at the last reported sales price on the last business day of the year. Shares of mutual funds are valued at the net asset value of shares held by the Plan at year end. Foreign bonds, equities and currencies are translated into U.S. dollars at end-of-period exchange rates.

The amounts shown in Note 6 for investments in limited partnership units represent estimated market value, which is based on the Plan's equity in the limited partnerships reported in the December 31 audited financial statements of the limited partnerships.

Purchases and sales of securities are recorded on a trade-date basis. Interest income is recorded on the accrual basis. Dividends are recorded on the ex-dividend date.

Actuarial Present Value of Accumulated Plan Benefits

Accumulated Plan benefits are those future periodic payments that are attributable under the Plan's provisions to the service employees have rendered. Accumulated Plan benefits include benefits expected to be paid to: (a) retired or terminated employees or their beneficiaries; (b) beneficiaries of employees who have died; and (c) present employees or their beneficiaries. Accumulated Plan benefits for active employees are based on benefit calculations using credited service, average qualifying salary, and average qualifying employment on the date as of which the benefit information is presented (the valuation date). Benefits payable under all circumstances (retirement, death and termination of employment) is included to the extent they are deemed attributable to employee service rendered to the valuation date.

The actuarial present value of accumulated Plan benefits is determined by the Plan's actuary and is the amount that results from applying actuarial assumptions to adjust the accumulated plan benefits to reflect the time value of money (through discounts for interest) and the probability of payment (by means of decrements such as for death, disability, withdrawal or retirement) between the valuation date and the expected date of payment.

Plan costs developed by the actuary are estimates of the amounts necessary to provide benefits to Plan participants assuming continued funding of the Plan in a systematic manner. These estimates are based on the actuarial methods selected to allocate the total cost of the Plan to various years and on actuarial assumptions regarding the return on investments, salary rates, withdrawal rates, mortality rates and other factors.

The significant actuarial assumptions used in the valuations as of January 1, 2003 (the latest valuation date) were:

Investment return	8.00%
Mortality	1983 Group Annuity Mortality Table

Additional assumptions used in the January 1, 2003 actuarial valuation were: (a) rates of retirement age by age group; (b) withdrawal rate assumptions by age group; and (c) disability assumptions by age group.

The foregoing actuarial assumptions are based on the presumption that the Plan will continue. Were the Plan to terminate, different actuarial assumptions and other factors might be applicable in determining the actuarial present value of accumulated Plan benefits.

Derivatives
The derivatives most commonly used by the investment managers are highly liquid over-the-counter forward foreign exchange contracts (Note 8). Forward foreign exchange contracts are marked-to-market based upon year-end exchange rates, and the difference between contract value and market value is recorded as an asset (liability) in the Plan's net assets available for pension benefits. The change in value of these forward exchange contracts is included as unrealized gains (losses) in the changes in net assets available for pension benefits. When the forward exchange contract is closed, the Plan transfers the unrealized appreciation (depreciation) to a realized gain (loss) equal to the change in the value of the forward exchange contract when it was opened and the value at the time it was closed or offset.

Administrative Expenses
Either the Plan or the Company, as provided in the Plan document, pays plan expenses.

Payment of Benefits
Benefit payments to participants are recorded upon distribution.

3. Funding Policy

The funding policy defines the employer contribution to be the cost of benefits accruing during the period plus a five-year amortization of the difference between the Plan's liabilities and the actuarial value of the Plan's assets (unfunded actuarial liability). In subsequent years, the difference between the actual unfunded actuarial liability and the expected unfunded actuarial liability will be amortized over five years. In addition, increases or decreases as a result of changes in Plan benefits, population coverages, assumptions or actuarial methods will be amortized over five years. The funding policy contribution will be no less than the minimum required contribution nor greater than the maximum deductible contribution. The Company's contributions for 2003 and 2002 exceeded the minimum funding requirement of ERISA.

Medical Benefits Funding
As permitted by Section 401(h) of the Internal Revenue Code ("IRC"), the Plan was amended January 1, 1989 to provide for the potential funding of retired employees' medical benefits that are not paid from other sources. A separate account (the "401(h) account") has been established and maintained in the Plan for such benefits. The related obligations are not a component of the PacifiCorp Retirement Plan's obligations in the statement of accumulated plan benefits but are reflected as obligations in the financial statements of the health and welfare benefit plan. Effective in 2002, a portion of the premiums paid by participants in the health and welfare benefit plan were included in the 401(h) account.

Assets in the separate 401(h) account cannot be used to fund pension benefits of the Plan. Likewise, the Plan's assets cannot be used to fund the post-retirement medical costs.

Retirees who have retired and qualify for post-retirement medical benefits under the PacifiCorp Welfare Benefits Plan No. 534 are eligible for funding of medical benefits pursuant to this amendment. However, the provisions of the medical plan can further limit retiree benefits by specifying additional eligibility requirements.

The aggregate amount of contributions to fund medical benefits is not allowed to exceed 25 percent of total actual contributions to the Plan, exclusive of any contributions to fund past service cost. Such limitation is measured from January 1, 1989.

4. Plan Termination

Although it has not expressed any intention to do so, the Company has the right under the Plan to discontinue its contributions at any time and to terminate the Plan subject to the provisions set forth in ERISA.

In the event of Plan termination, the assets shall be allocated and distributed as prescribed by ERISA and its related regulations, generally to provide the following benefits in the order indicated:

a. Benefits that have been in pay status for three years or more or could have been in pay status for three years if the participant had then retired and received the normal form of benefit. The allocation is based on the lowest benefit provided by Plan provisions in effect within the last five years.
b. Other benefits guaranteed under ERISA disregarding Section 4022(b)(5) and (6), including benefits not covered by (a) because of the exclusion of benefit increases within five years.
c. All other vested accrued benefits, including benefits not covered by (b) above.
d. All other accrued benefits.

Amounts in the medical benefits account shall be used to pay medical benefits only. Following satisfaction of the obligations, any amounts remaining shall be returned to the Company as provided in the Plan document.

The Pension Benefit Guaranty Corporation ("PBGC") insures certain benefits under the Plan if the Plan terminates. Generally, the PBGC guarantees most vested normal age retirement benefits, early retirement benefits, and certain disability and survivor's pensions. However, the PBGC does not guarantee all types of benefits under the Plan, and the amount of benefit protection is subject to certain limitations. Vested benefits under the Plan are guaranteed at the level in effect on the date of the Plan's termination. However, there is a statutory ceiling on the amount of an individual's monthly benefit that the PBGC guarantees. Whether all participants receive their benefits should the Plan terminate at some time will depend on the sufficiency at that time of the Plan's net assets to provide those benefits and may also depend on the level of benefits guaranteed by the PBGC.

5. Information Certified by the Trustees

Deutsche Bank Trust Company Americas ("Deutsche Bank") was the trustee of the Plan through April 30, 2003. Effective May 1, 2003, State Street Bank & Trust Company ("State Street") became the trustee of the Plan, as State Street acquired Deutsche Bank during 2003.

The trustees hold all investments and execute all transactions on behalf of the Plan, which includes investments and investment activity of net assets held for 401(h) account. Information regarding fair value of short-term investments, U.S. government securities, corporate bonds, common stock, mutual funds, other investments, interest and dividends receivable, due from brokers for securities sold, payables due to brokers for securities purchased, investment income (loss), and investments and investment activity included in net assets held for 401(h) account has been certified by the trustees as being complete and accurate and therefore has not been audited by the independent auditors.

6. Investments

The following table presents the fair values of investments. Investments that represent 5 percent or more of the Plan's net assets are separately identified.

	2003	2002
Investments at fair value as determined by quoted market prices		
Short-term investments	$ 16,988,351	$ 10,247,703
U.S. government securities	115,382,186	94,706,110
Corporate bonds	50,360,030	57,754,878
Common stock	275,889,623	221,155,513
The Boston Company International ACWI Fund	59,095,446	42,373,564
SSGA Passive Bond Market Index	73,949,885	70,732,898
NTGI QM Collective Daily - S&P 500 Index Fund	49,127,054	-
Pyramid Equity Index Fund	-	78,270,413
Mutual funds	15,747,717	16,687,807
Investment of securities lending collateral, at cost and market value	33,067,927	44,250,385
Other investments	-	734,027
	689,608,219	636,913,298
Investments at estimated fair value		
Limited partnership units	81,736,302	81,755,409
Total investments	$ 771,344,521	$ 718,668,707

During 2003 and 2002, the Plan's investments (including gains and losses on investments bought and sold, as well as held during the year) appreciated (depreciated) in value by $127,244,022 and $(69,386,463), respectively, as follows:

Net appreciation (depreciation) in fair value	**2003**	**2002**
Investments at fair value as determined by quoted market prices		
Short-term investments	$ 416,149	$ 2,738,378
U.S. government securities	6,519,915	13,481,815
Corporate bonds	799,654	(82,186)
Common stock	71,753,863	(64,972,718)
Mutual funds	39,159,759	203,633
Other investments	(133,287)	(7,491,085)
	118,516,053	(56,122,163)
Investments at estimated fair value		
Limited partnership units	8,727,969	(13,264,300)
	$ 127,244,022	$ (69,386,463)

7. Securities Lending

The Plan participates in a securities lending program with State Street. This program allows State Street to loan securities, which are assets of the Plan, to approved brokers. State Street requires borrowers, pursuant to a security loan agreement, to deliver collateral to secure each loan. In the event of default by the borrower, State Street shall indemnify the Plan by purchasing replacement securities equal to the number of unreturned loaned securities or, if replacement securities are not able to be purchased, State Street shall credit the Plan for the market value of the unreturned securities. In each case, State Street would apply the proceeds from the collateral for such loan to make the Plan whole.

The market value of the securities on loan to approved brokers at December 31, 2003 and 2002 was $32,134,310 and $44,703,878, respectively. Cash collateral received for securities on loan was invested in State Street Navigator Securities Lending Prime Portfolio at December 31, 2003, and in Institutional Daily Assets Fund at December 31, 2002. Noncash collateral of $0 and $2,510,180 received for securities on loan at December 31, 2003 and 2002, respectively, consisted of U.S. Treasury notes and bonds and letters of credit held by State Street on behalf of the Plan.

8. Forward Foreign Currency Exchange Contracts

In connection with portfolio purchases and sales of securities denominated in a foreign currency, the Plan may enter into foreign currency exchange contracts ("contracts") for hedging purposes. Additionally, the Plan enters into forward contracts to hedge certain other foreign currency denominated assets. Contracts are valued at the prevailing forward exchange rate of the underlying currencies. The Fund could be exposed to risks if counterparties to the contracts are unable to meet the terms of their contract or if the value of the foreign currency changes unfavorably. Realized losses arising from such transactions amounted to $261,521 and are included in investment loss from foreign currency transactions.

PacifiCorp Retirement Plan
Notes to Financial Statements
December 31, 2003 and 2002

As of December 31, 2003, the Plan had entered into the following forward contracts:

Currency to be Delivered		Currency to be Received		Settlement Date	Unrealized Appreciation (Depreciation) US$
622,347	Australian Dollars	371,550	Euros	1/8/04	$ 3,400
4,709,577	British Pound	6,726,298	Euros	1/5 -3/5/04	76,831
2,670,922	Canadian Dollars	1,719,957	Euros	1/29/04	103,578
525,394	Danish Krone	70,580	Euros	1/8/04	903
18,891	Euros	31,614	Australian Dollars	1/6/04	163
460,747	Euros	758,099	Canadian Dollars	1/29/04	5,180
5,911	Euros	9,215	Swiss Franc	1/5/04	75
26,185,051	Japanese Yen	320,385	Canadian Dollars	1/20/04	3,218
1,203,405,271	Japanese Yen	9,225,057	Euros	1/5 - 1/29/04	391,747
1,400,133	New Zealand Dollars	741,694	Euros	1/5 - 3/8/04	22,345
35,153,237	Swedish Krona	3,907,487	Euros	1/8 - 1/29/04	46,890
141,373	US Dollars	197,448	Australian Dollars	1/29/04	6,883
1,252,400	US Dollars	1,655,672	Canadian Dollars	1/23/04	27,492
10,556,322	US Dollars	8,700,308	Euros	1/5 - 2/23/04	408,061
6,891,350	US Dollars	749,464,508	Japanese Yen	1/29/04	108,173
1,799,375	US Dollars	14,016,772	Swedish Krona	1/22/04	146,511
188,556	US Dollars	264,383	Swiss Franc	1/30/04	25,372
					1,376,822
913,630	Australian Dollars	654,159	US Dollars	1/29/04	(31,852)
2,176,155	British Pound	3,679,878	US Dollars	1/29/04	(207,206)
913,744	Canadian Dollars	699,785	US Dollars	1/29/04	(6,378)
370,870	Euros	622,347	Australian Dollars	1/29/04	(124)
11,416,895	Euros	8,056,467	British Pound	1/29 - 3/5/04	(14,262)
70,580	Euros	525,394	Danish Krone	1/29/04	(27)
4,813,688	Euros	628,779,241	Japanese Yen	1/20 - 1/23/04	(197,462)
566,835	Euros	2,643,432	Polish Zloty	2/2/04	(10,792)
103,733	Euros	940,723	Swedish Krona	1/29/04	(189)
15,718,301	Euros	18,800,196	US Dollars	1/29 - 2/23/04	(1,003,020)
37,522,845	Japanese Yen	336,675	US Dollars	1/29 - 3/4/04	(13,935)
11,370,255	Mexican Peso	1,006,574	US Dollars	1/20/04	(2,424)
3,753,485	Polish Zloty	792,661	Euros	2/2/04	(56)
373,401	Swiss Franc	166,245	British Pound	5/12/04	(8,392)
586,147	Swiss Franc	49,048,781	Japanese Yen	5/26/04	(15,773)
264,383	Swiss Franc	196,611	US Dollars	1/30/04	(17,317)
3,803,297	US Dollars	407,333,051	Japanese Yen	1/20/04	(128)
					(1,529,337)
					$ (152,515)

9. Risks and Uncertainties

The Plan investments consist primarily of financial instruments including short-term investments, U.S. government securities, corporate bonds, common stock and limited partnership venture capital. These financial instruments may subject the Plan to concentrations of risk on occasion in which cash balances exceed amounts insured by the Federal Deposit Insurance Corporation, market values of securities are dependent on the ability of the issuer to honor its contractual commitments, and investments in common stock are subject to changes in market values of the stock. Due to the level of risks associated with certain investment securities, it is at least reasonably possible that changes in the values of investment securities will occur in the near term and that such changes could materially affect the amounts reported in the financial statements.

Plan contributions are made and the actuarial present value of accumulated plan benefits are reported based on certain assumptions pertaining to interest rates, inflation rates and employee demographics, all of which are subject to change. Due to uncertainties inherent in the estimations and assumptions process, it is at least reasonably possible that changes in these estimates and assumptions in the near term would be material to the financial statements.

10. Party-in-Interest

The Plan's investment assets represent funds invested in, or maintained by, State Street and Deutsche Bank. State Street and Deutsche Bank are the trustees, as defined by the Plan and, therefore, these transactions qualify as party-in-interest. The Company pays for some of the Plan's expenses, as provided in the Plan document.

11. Plan Amendments

Effective January 1, 2002, participants who were employees of the Western Systems Coordinating Council ("WSCC") ceased to accrue benefits under the Plan. An asset balance of $2,047,400 was transferred to the WSCC Retirement Trust Fund.

12. Tax Status

The Internal Revenue Service has determined and informed the Company by letter dated May 6, 2002, that the Plan and related trust are designed in accordance with applicable sections of the Internal Revenue Code ("IRC"). The Plan has been amended since receiving the determination letter. However, the Plan administrator and the Plan's tax counsel believe that the Plan remains in compliance with the applicable provisions of the IRC.

13. Reconciliation of Financial Statements to Form 5500

The following is a reconciliation of net assets available for Plan benefits at December 31 per the financial statements to Form 5500:

	2003	**2002**
Net assets available for benefits per financial statements	$ 800,645,958	$711,292,602
Net assets held in 401(h) account included as assets in Form 5500	59,571,733	49,236,183
Net assets available for benefits per Form 5500	$ 860,217,691	$760,528,785

The net assets of the 401(h) account included in Form 5500 are not available to pay pension benefits but can be used only to pay retiree health benefits.

PacifiCorp Retirement Plan
Notes to Financial Statements
December 31, 2003 and 2002

The following is a reconciliation of the changes in net assets for the years ended December 31 per the financial statements to Form 5500:

	Amounts per Financial Statements	401(h) Account	Amounts per Form 5500
2003			
Net appreciation in fair value of investments	$ 127,244,022	$ 9,474,095	$ 136,718,117
Interest	7,145,879	532,054	7,677,933
Dividends	6,331,082	471,388	6,802,470
Income on pooled funds	508,888	37,890	546,778
Securities lending income	76,067	5,664	81,731
Foreign currency transactions	(337,547)	(25,135)	(362,682)
Investment expenses, administrative expenses and PBGC premiums paid	5,375,383	264,262	5,639,645
Employer contributions	61,555,151	13,000,000	74,555,151
Participant contributions	-	2,480,929	2,480,929
Benefits paid	107,794,803	14,092,731	121,887,534
Insurance premiums paid	-	1,284,342	1,284,342

	Amounts per Financial Statements	401(h) Account	Amounts per Form 5500
2002			
Net depreciation in fair value of investments	$ (69,386,463)	$ (378,141)	$ (69,764,604)
Interest	11,856,591	70,056	11,926,647
Dividends	6,101,218	33,250	6,134,468
Income on pooled funds	1,032,834	5,629	1,038,463
Securities lending income	85,148	464	85,612
Foreign currency transactions	(2,432,089)	(13,254)	(2,445,343)
Investment expenses	2,879,067	15,690	2,894,757
Employer contributions	33,448,581	16,083,538	49,532,119
Participant contributions	-	1,025,528	1,025,528
Benefits paid	111,383,354	12,104,950	123,488,304
Administrative expenses	1,444,963	151,036	1,595,999
Insurance premiums paid	-	1,409,582	1,409,582

14. Restatement

The 2002 financial statements have been restated for the following: a) to include the Plan's investments by type in the Statement of Net Assets Available for Pension Benefits; b) to record the effect of securities lending transactions (Note 7) in accordance with Statement of Financial Accounting Standards No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities*; and (c) to present the net assets held in a 401(h) account related to health and welfare plan obligations for retirees in accordance with AICPA Statement of Position No. 99-2, *Accounting for and Reporting of Postretirement Medical Benefit (401(h)) Features of Defined Benefit Pension Plans*. The effect of this restatement is as follows:

	As Previously Reported	As Restated
Statement of Net Assets Available for Pension Benefits		
Investments, at fair value:		
Plan interest in PacifiCorp Master Retirement Trust	$ 677,844,021	$ -
Short-term investments	-	10,247,703
U.S. government securities	-	94,706,110
Corporate bonds	-	57,754,878
Common stock	-	221,155,513
Mutual funds	-	208,064,682
Investment of securities lending collateral, at cost and market value	-	44,250,385
Limited partnership units	-	81,755,409
Other investments	-	734,027
Receivables:		
Interest and dividends	-	2,714,269
Due from brokers for securities sold	-	2,733,187
Payables:		
Payables due to brokers for securities purchased	-	2,021,757
Payable for securities lending collateral	-	44,250,385
Statement of Changes in Net Assets Available for Pension Benefits		
Plan interest in PacifiCorp Master Retirement Trust investment loss	(55,731,474)	-
Net depreciation in fair value of investments	-	(69,386,463)
Interest	-	11,856,591
Dividends	-	6,101,218
Income on pooled funds	-	1,032,834
Securities lending income	-	85,148
Foreign currency transactions	-	(2,432,089)
Investment expenses	-	2,879,067
Other receipts	109,646	-

Supplemental Schedules

PacifiCorp Retirement Plan
Schedule H, Line 4i – Schedule of Assets (Held at End of Year)
December 31, 2003

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment Including Maturity Date, Rate of Interest, Collateral, Par or Maturity Value			(d) Cost	(e) Current Value
	Short-term investments					
	CASH				$ 3,255,348.48	$ 3,359,984.34
	PACIFICORP SPIFF				5,282,648.84	5,282,648.84
*	STATE STREET BANK + TRUST CO				9,416,191.54	9,416,191.54
	Total short-term investments				**17,954,188.86**	**18,058,824.72**
	U.S. government securities					
	AUSTRALIA (CMNWLTH)	August 20, 2015	4.000%	$ 470,000.00	447,199.30	482,869.48
	AUSTRALIA(CMNWLTH)	November 15, 2006	6.750%	750,000.00	571,773.72	585,555.01
	BANK ONE CAP III	September 1, 2030	8.750%	500,000.00	654,085.00	635,378.35
	BELGIUM (KINGDOM OF)	March 28, 2028	5.500%	830,000.00	888,640.37	1,127,010.44
	BELGIUM (KINGDOM)	September 28, 2013	4.250%	380,000.00	411,737.80	476,245.62
	CANADA GOVT	September 1, 2007	4.500%	1,954,000.00	1,425,360.21	1,556,395.59
	CANADA GOVT	June 1, 2012	5.250%	2,332,000.00	1,872,813.28	1,887,977.09
	CANADA GOVT	December 1, 2031	4.000%	1,536,525.90	1,234,771.73	1,466,670.30
	DENMARK KINGDOM OF	November 15, 2013	5.000%	11,170,000.00	1,557,085.41	1,967,898.49
	DEV BK OF JAPAN	September 20, 2022	1.700%	34,000,000.00	270,847.25	307,894.00
	FED HM LN PC POOL E01137	March 1, 2017	6.000%	44,618.99	46,213.76	46,973.69
	FED HM LN PC POOL E01140	May 1, 2017	6.000%	1,564,977.20	1,617,061.59	1,647,566.37
	FED HM LN PC POOL G10413	November 1, 2010	6.500%	2,575,126.43	2,711,527.66	2,731,746.39
	FED HM LN PC POOL G10471	February 1, 2011	6.500%	2,737,161.08	2,882,145.08	2,903,636.04
	FED HM LN PC POOL G11122	May 1, 2016	6.500%	1,669,137.40	1,756,767.11	1,770,654.84
	FED HM LN PC POOL G11210	December 1, 2016	5.500%	1,714,261.41	1,756,582.23	1,790,170.96
	FED HM LN PC POOL G11431	February 1, 2018	6.000%	2,172,182.27	2,246,172.23	2,286,815.71
	FED HM LN PC POOL G11433	September 1, 2017	6.000%	2,291,821.72	2,385,643.17	2,410,763.60
	FED NATL MTG ASSN GTD REMIC	June 25, 2030	7.500%	2,650,593.64	2,906,541.59	2,873,419.77
	FEDERAL HOME LN BKS	October 15, 2004	3.625%	275,000.00	282,294.90	279,893.21
	FEDERAL NATL MTG ASSN	May 15, 2011	6.000%	590,000.00	592,354.24	653,590.08
	FNMA POOL 190308	September 1, 2030	7.500%	40,999.59	42,857.39	43,994.48
	FNMA POOL 535862	May 1, 2011	6.113%	656,955.79	725,268.92	721,809.35
	FNMA POOL 545179	September 1, 2011	6.258%	273,904.72	296,758.65	303,318.85
	FNMA POOL 545210	October 1, 2011	6.118%	1,466,202.00	1,614,555.73	1,595,048.02
	FNMA POOL 545811	June 1, 2017	7.000%	3,456,782.24	3,676,611.98	3,705,103.30
	FNMA POOL 555803	January 1, 2022	1.000%	1,221,350.53	1,278,792.18	1,290,567.03
	FNMA POOL 606557	October 1, 2016	6.500%	834,412.43	847,841.26	886,726.17
	FNMA POOL 725038	December 1, 2018	5.500%	2,445,000.00	2,516,248.83	2,531,339.06
	GERMANY (FED REP)	November 26, 2004	4.250%	1,000,000.00	1,186,648.85	1,284,054.89
	GERMANY (FED REP OF)	January 4, 2030	6.250%	510,000.00	778,584.91	766,218.07
	GERMANY (FEDERAL REPUBLIC OF)	January 4, 2031	5.500%	777,000.00	797,954.88	1,062,438.35
	GERMANY (FEDERAL REPUBLIC)	April 11, 2008	3.000%	2,540,000.00	2,894,398.33	3,153,850.71
	GERMANY FED REP	January 4, 2009	3.750%	4,020,000.00	4,758,506.08	5,118,039.71
	GERMANY FED REP	January 4, 2009	3.750%	250,000.00	307,392.32	318,286.05
	GERMANY(FED REP)	February 18, 2005	4.250%	3,060,000.00	3,882,825.48	3,943,874.94
	GERMANY(FED REP)	March 18, 2005	2.500%	1,679,000.00	2,108,331.89	2,122,996.25
	GERMANY(FED REP)	January 4, 2013	4.500%	3,220,000.00	4,003,776.73	4,146,435.23
	GERMANY(FED REP)	January 4, 2028	5.625%	100,000.00	92,882.56	138,294.48
	GERMANY(FEDERAL REPUBLIC OF	February 17, 2006	5.000%	750,000.00	972,636.25	990,191.74
	GERMANY(FEDERAL REPUBLIC OF	February 17, 2006	5.000%	20,000.00	24,074.24	26,405.11
	GREECE(REP OF)	May 20, 2013	4.600%	100,000.00	105,627.63	127,882.03
	ICELAND (REP OF)	January 1, 2020	1.000%	220,000,000.00	2,585,641.41	3,076,958.88
	ITALY REPUBLIC OF	July 1, 2005	4.750%	850,000.00	748,944.87	1,108,062.81
	ITALY REPUBLIC OF BTP	July 15, 2005	4.000%	40,000.00	44,219.81	51,619.51
	JAPAN (GOVERNMENT)	June 20, 2013	1.000%	132,000,000.00	1,086,486.82	1,198,062.89
	JAPAN (GOVERTMENT OF)	November 20, 2005	0.100%	500,000,000.00	4,612,971.68	4,666,371.19
	JAPAN (GOVT OF)	June 20, 2006	0.400%	232,700,000.00	1,763,190.33	2,182,694.30
	JAPAN (GOVT OF)	September 20, 2006	0.500%	410,000,000.00	3,342,995.95	3,857,339.83
	JAPAN (GOVT OF)	September 20, 2013	1.600%	198,000,000.00	1,818,965.02	1,891,207.61
	JAPAN GOVT OF	December 20, 2007	2.000%	130,000,000.00	1,269,604.04	1,289,252.59
	JAPAN GOVT OF	December 21, 2020	2.500%	20,650,000.00	161,749.93	215,527.08
	JAPAN(GOVT OF)	June 20, 2008	1.800%	407,000,000.00	3,637,749.42	4,017,306.85

PacifiCorp Retirement Plan
Schedule H, Line 4i – Schedule of Assets (Held at End of Year)
December 31, 2003

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment Including Maturity Date, Rate of Interest, Collateral, Par or Maturity Value			(d) Cost	(e) Current Value
	JAPAN(GOVT OF)	June 20, 2012	1.400%	133,000,000.00	1,161,003.30	1,261,653.36
	JAPAN(GOVT)	December 20, 2010	1.900%	11,000,000.00	98,700.34	109,078.39
	NETHERLANDS KINGDOM OF	July 15, 2012	5.000%	100,000.00	117,933.88	133,286.92
	NEW ZEALAND (GOVERNMENT OF)	April 15, 2015	6.000%	1,400,000.00	878,459.01	919,170.15
	POLAND GOVT OF	May 12, 2007	8.500%	700,000.00	196,738.80	198,616.05
	POLAND GOVT OF	November 24, 2010	6.000%	3,500,000.00	998,523.89	902,375.16
	POLAND(GOVT OF)	August 12, 2005	0.000%	1,850,000.00	436,502.33	451,514.87
	SPAIN (KINGDOM OF)	July 30, 2032	5.750%	530,000.00	686,253.61	748,514.42
	SWEDEN (KINGDOM OF)	August 15, 2007	8.000%	5,900,000.00	642,654.44	934,252.08
	SWEDEN (KINGDOM)	December 1, 2008	4.000%	21,000,000.00	2,987,423.21	3,569,016.44
	SWEDEN KINGDOM OF	March 15, 2011	5.250%	13,200,000.00	1,250,739.07	1,920,790.52
	SWEDEN(KINGDOM OF)	October 8, 2012	5.500%	4,100,000.00	533,034.25	603,036.70
	SWEDEN(KINGDOM OF)	October 8, 2012	5.500%	12,400,000.00	1,400,985.55	1,823,818.33
	SWEDEN(KINGDOM OF)	May 5, 2014	6.750%	600,000.00	84,970.01	96,579.71
	UNITED STATES TREAS BDS	February 15, 2031	5.375%	540,000.00	551,221.88	563,287.50
	UNITED STATES TREAS NTS	May 31, 2004	3.250%	3,400,000.00	3,455,781.25	3,431,343.92
	UNITED STATES TREAS NTS	November 15, 2004	5.875%	6,500,000.00	6,853,750.00	6,761,015.30
	UNITED STATES TREAS NTS	May 15, 2006	6.875%	1,900,000.00	2,125,921.88	2,112,265.72
	UNITED STATES TREAS NTS	November 15, 2006	3.500%	2,190,000.00	2,253,646.88	2,263,912.50
	UNITED STATES TREAS NTS	January 15, 2007	3.375%	394,202.80	472,951.31	426,970.91
	UNITED STATES TREAS NTS	May 15, 2007	4.375%	1,400,000.00	1,475,031.25	1,482,906.32
	UNITED STATES TREAS NTS	February 15, 2008	3.000%	2,400,000.00	2,405,675.61	2,411,250.00
	UNITED STATES TREAS NTS	July 15, 2012	3.000%	740,696.25	779,111.45	806,433.04
	UNITED STATES TREAS NTS	November 15, 2012	4.000%	500,000.00	487,773.43	495,390.60
	UNITED STATES TREAS NTS	August 15, 2013	4.250%	505,000.00	503,027.34	505,789.06
	Total U.S. governement securities				**115,340,525.97**	**122,652,670.36**
Corporate bonds						
	AETNA INC NEW	March 1, 2006	7.375%	300,000.00	299,052.00	327,280.14
	ALTRIA GROUP INC	November 4, 2013	7.000%	264,000.00	265,311.18	279,589.07
	AMERADA HESS CORP	October 1, 2029	7.875%	150,000.00	164,433.00	164,486.89
	AMERADA HESS CORP	August 15, 2011	6.650%	250,000.00	268,992.00	269,187.92
	ANGLO AMERICAN PLC	June 5, 2008	3.625%	250,000.00	285,694.42	312,814.94
	ASIAN DEV BANK	June 29, 2005	3.125%	55,000,000.00	498,458.96	536,913.32
	AT + T CORP	November 15, 2011	7.300%	850,000.00	936,086.50	968,538.28
	AT+T CORP	November 15, 2031	1.000%	1,250,000.00	1,351,218.20	1,432,800.12
	AUST + NZ BANK GRP	February 5, 2015	4.450%	300,000.00	344,447.28	381,602.70
	BANK OF AMERICA	February 15, 2010	7.800%	400,000.00	467,600.64	477,122.44
	BANK OF AMERICA CORPORATION	October 21, 2010	4.425%	120,000.00	138,989.03	150,907.98
	BANK OF SCOT	April 22, 2015	4.875%	200,000.00	248,204.88	254,048.62
	BANK OF SCOTLAND	December 5, 2013	5.125%	160,000.00	142,371.38	211,957.35
	BANK ONE CORP	June 30, 2008	2.625%	375,000.00	352,839.04	361,425.04
	BARCLAYS BANK PLC	March 31, 2013	4.875%	112,000.00	136,970.18	144,181.45
	BAT INTL FINANCE	February 25, 2009	4.875%	250,000.00	296,063.31	320,319.98
	BOSTON PPTYS LTD PARTNERSHIP	January 15, 2013	6.250%	325,000.00	339,465.75	351,356.30
	BOSTON PPTYS LTD PARTNERSHIP	April 15, 2015	5.625%	500,000.00	488,153.00	512,128.90
	BP CAP MKTS P L C	May 27, 2005	4.625%	200,000.00	199,156.00	207,614.06
	CASINO GUICHARD PERRACHON	March 6, 2008	6.000%	250,000.00	307,165.84	337,978.89
	CIGNA CORP	May 15, 2027	7.875%	425,000.00	453,431.50	464,475.78
	CIGNA CORP	October 15, 2011	6.375%	650,000.00	677,469.00	676,783.05
	CINGULAR WIRELESS LLC	December 15, 2011	6.500%	150,000.00	149,379.00	165,515.08
	CIT GROUP INC NEW	September 25, 2007	5.750%	400,000.00	426,036.00	431,835.96
	CITIGROUP INC	December 1, 2005	6.750%	450,000.00	493,892.68	489,501.27
	COMCAST CORP NEW	January 15, 2014	5.300%	850,000.00	826,195.00	847,474.31
	COMCAST CORP NEW	January 15, 2014	5.300%	450,000.00	449,244.00	448,662.87
	CONTINENTAL AG	December 5, 2008	6.875%	210,000.00	260,911.86	296,470.99
	CORE INVT GRADE BD TR I	November 30, 2007	4.727%	610,000.00	610,000.00	632,661.50
	CREDIT LYONNAIS	November 15, 2012	1.000%	450,000.00	486,530.07	593,547.43
	CREDIT SUISSE GP	December 23, 2005	6.000%	53,000.00	35,461.13	58,324.64
	CRH AMER INC	March 15, 2012	6.950%	350,000.00	349,657.00	392,500.22
	DEERE + CO	May 15, 2010	7.850%	380,000.00	383,659.40	453,252.33
	DEUTSCHE BK CAP FD	September 29, 2049	1.000%	250,000.00	295,153.08	320,164.20

PacifiCorp Retirement Plan
Schedule H, Line 4i – Schedule of Assets (Held at End of Year)
December 31, 2003

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment Including Maturity Date, Rate of Interest, Collateral, Par or Maturity Value			(d) Cost	(e) Current Value
	DEUTSCHE TELEKOM INTL FIN	July 6, 2005	1.000%	200,000.00	202,454.23	266,144.97
	DEUTSCHE TELEKOM INTL FIN BV	May 29, 2012	8.125%	220,000.00	312,004.21	340,683.22
	DILLARD DEPT STORES INC	August 1, 2011	9.125%	800,000.00	800,000.00	886,000.00
	ENI	April 30, 2013	4.625%	540,000.00	644,575.76	686,374.01
	EOP OPERATIONS LP	February 15, 2012	6.750%	550,000.00	593,978.00	612,124.42
	FONTERRA CO OP GROUP	May 21, 2007	5.250%	50,000.00	49,856.85	66,542.55
	FORD MTR CR CO	October 28, 2009	7.375%	1,050,000.00	1,078,400.62	1,153,470.88
	FORD MTR CR CO	October 25, 2011	7.250%	750,000.00	784,620.00	814,796.02
	FORD MTR CR CO	October 1, 2013	7.000%	100,000.00	101,691.00	105,471.47
	FRANCE TELECOM	January 28, 2033	8.125%	100,000.00	143,023.25	162,077.24
	FRANCE TELECOM	January 28, 2013	7.250%	130,000.00	153,245.03	190,982.35
	GALLAHER GROUP PLC	October 2, 2006	5.750%	475,000.00	523,236.76	632,633.54
	GEN MOTORS ACC CP	July 3, 2013	7.250%	100,000.00	126,938.86	140,199.12
	GENERAL ELEC CO	February 1, 2013	5.000%	900,000.00	886,394.61	914,527.44
	GENERAL MTRS ACCEP CORP	September 15, 2011	6.875%	1,250,000.00	1,270,597.50	1,353,968.12
	GENERAL MTRS ACCEP CORP	July 15, 2006	4.500%	425,000.00	422,173.79	437,878.90
	GMAC SWIFT TRUST 1	January 18, 2005	5.000%	300,000.00	300,234.31	388,111.27
	GOLDMAN SACHS GROUP INC	August 4, 2010	4.250%	170,000.00	191,592.52	213,443.22
	GREEN TREE FINL CORP	February 15, 2027	6.880%	.03	0.03	0.03
	HARRAHS OPER INC	June 1, 2007	7.125%	125,000.00	131,278.75	138,650.81
	HCA HEALTHCARE CO	September 1, 2010	8.750%	450,000.00	492,804.00	530,437.50
	HCA HEALTHCARE CO	February 1, 2011	7.875%	500,000.00	527,540.00	570,000.00
	HCA INC	July 15, 2013	6.750%	450,000.00	464,206.50	472,500.00
	HEALTH NET INC	April 15, 2011	8.375%	275,000.00	331,353.00	321,945.69
	HERTZ CORP	October 2, 2006	4.700%	210,000.00	209,964.30	210,426.49
	HEWLETT PACKARD CO	July 1, 2007	5.500%	600,000.00	640,734.00	647,671.08
	HSBC BANK	March 18, 2016	4.250%	140,000.00	163,397.49	174,408.21
	HSBC HLDGS PLC	December 12, 2012	5.250%	300,000.00	299,217.00	307,218.00
	IMC HOME EQUITY LN TR	August 20, 2028	7.520%	.01	0.01	0.01
	INTERNATIONAL PAPER CO	September 1, 2011	6.750%	290,000.00	294,142.11	320,159.97
	INTERNATIONAL PAPER CO	April 1, 2015	5.300%	200,000.00	199,590.00	195,780.62
	INVESTOR AB	September 10, 2010	4.750%	200,000.00	229,083.98	253,014.31
	LIBERTY MEDIA CORP NEW	May 15, 2013	5.700%	60,000.00	59,776.80	61,189.10
	LOCKHEED MARTIN CORP	December 1, 2029	8.500%	375,000.00	472,253.95	488,767.91
	MAY DEPT STORES CO	March 1, 2030	7.875%	1,125,000.00	1,253,385.25	1,336,526.21
	MMO2	January 25, 2007	6.375%	250,000.00	317,719.50	340,091.65
	NEWS AMER HLDGS INC	February 1, 2013	9.250%	200,000.00	256,186.00	261,100.04
	PEMEX PROJ FDG MASTER TR	August 5, 2013	6.250%	230,000.00	257,406.91	287,499.64
	PHILLIPS PETE CO	May 25, 2005	8.500%	250,000.00	275,610.00	272,916.47
	RAYCHEM CORP	October 15, 2008	8.200%	550,000.00	601,562.50	621,500.00
	RAYTHEON CO	December 15, 2018	6.400%	600,000.00	599,928.00	628,990.62
	RAYTHEON CO	August 15, 2027	7.200%	250,000.00	283,865.00	272,033.85
	RENTOKIL INITIAL	May 21, 2007	5.750%	260,000.00	264,169.68	348,907.23
	REPSOL INTERNATIONAL	July 22, 2013	5.000%	80,000.00	97,157.98	100,908.05
	RESIDENTIAL FDG MTG SECS I INC	May 25, 2018	5.000%	.01	0.01	0.01
	SAFECO CORP	September 1, 2012	7.250%	350,000.00	396,291.00	406,650.37
	SANTANDER CENTRAL HISPANO ISS	April 10, 2012	1.000%	200,000.00	248,935.45	268,970.40
	SCHERING PLOUGH CORP	December 1, 2013	5.300%	250,000.00	249,077.50	251,489.75
	SLM CORPORATION	July 25, 2008	3.250%	140,000.00	145,849.10	171,291.41
	SLM STUDENT LN TR	October 25, 2010	1.000%	.01	0.01	0.01
	SMALL BUSINESS ADMIN	August 1, 2023	5.240%	750,000.00	750,000.00	764,062.50
	SMALL BUSINESS ADMIN	September 1, 2023	1.000%	800,000.00	800,000.00	809,504.00
	SMALL BUSINESS ADMIN	November 1, 2023	4.980%	850,000.00	850,000.00	851,062.50
	SMFG FINANCE	July 11, 2005	2.250%	15,000,000.00	109,955.97	262,083.61
	SMFG FINANCE (KY)	July 11, 2005	2.250%	3,000,000.00	39,424.28	52,626.67
	SOGERIM	April 20, 2006	6.125%	120,000.00	150,214.83	160,950.86
	SOGERIM SA	April 20, 2011	7.000%	240,000.00	318,813.39	343,198.36
	ST PAUL COS INC MTN BK ENT	December 15, 2008	6.380%	300,000.00	323,922.00	328,106.40
	TELEFONICA EUROPE BV	February 14, 2013	5.125%	180,000.00	195,712.30	233,797.64
	TELEKOM FINANZMANAGEMENT GMBH	July 22, 2013	5.000%	250,000.00	293,098.25	316,898.57
	TIMCO AVIATION SVCS INC	January 2, 2007	8.000%	998.00	-	49.90

PacifiCorp Retirement Plan
Schedule H, Line 4i – Schedule of Assets (Held at End of Year)
December 31, 2003

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment Including Maturity Date, Rate of Interest, Collateral, Par or Maturity Value			(d) Cost	(e) Current Value
	TIME WARNER ENTMT CO L P	July 15, 2033	8.375%	675,000.00	790,121.25	853,530.55
	TIME WARNER INC	April 15, 2031	7.625%	1,350,000.00	1,446,448.00	1,557,091.62
	TOYOTA MOTOR CREDIT CORP	October 11, 2005	7.000%	500,000.00	555,485.00	541,750.00
	U S DEPT VETERAN AFFAIRS REMIC	July 15, 2030	1.000%	1,602,762.12	1,725,724.02	1,723,248.80
	U S DEPT VETERAN AFFAIRS REMIC	July 15, 2012	7.250%	3,000,000.00	3,154,687.50	3,094,709.70
	UNION PAC CORP	February 15, 2009	3.875%	250,000.00	244,795.27	249,224.02
	UNION PACIFIC RAILROAD	January 10, 2021	8.000%	299,600.45	356,251.90	365,334.35
	UNITED MEXICAN STATES	December 24, 2009	9.000%	110,000.00	1,016,324.81	1,010,798.91
	UNUMPROVIDENT CORP	March 1, 2011	7.625%	375,000.00	392,812.50	403,806.00
	UNUMPROVIDENT CORP	June 15, 2032	7.375%	400,000.00	384,218.75	399,682.44
	VEOLIA ENVIRONNEMENT	May 28, 2013	4.875%	250,000.00	283,266.02	312,058.13
	VERIZON WIRELESS CAP LLC	December 15, 2006	5.375%	350,000.00	348,337.50	373,451.61
	VIACOM INC	May 15, 2033	5.500%	100,000.00	99,201.00	93,843.30
	WAL MART STORES INC	June 15, 2005	4.150%	200,000.00	199,600.00	206,572.08
	WELLS FARGO +CO NEW	August 24, 2005	7.250%	600,000.00	660,627.84	651,357.84
	WPP GROUP PLC	June 18, 2008	6.000%	250,000.00	300,707.60	339,129.87
	WYETH	March 15, 2011	6.700%	500,000.00	562,370.00	561,475.95
	WYETH	March 15, 2006	6.250%	315,000.00	344,261.26	341,277.96
	WYETH	February 1, 2014	5.500%	500,000.00	499,020.00	502,243.50
	XEROX CORP	June 15, 2010	7.125%	1,800,000.00	1,806,125.00	1,930,500.00
	Total corporate bonds				**50,776,721.66**	**53,533,325.84**
Common stock						
	3M CO			21,000.00	1,471,031.80	1,785,630.00
	ABITIBI CONSOLIDATED INC			18,700.00	143,151.05	150,063.07
	ABN AMRO HLDGS NV			32,272.00	575,913.07	755,101.97
	ACCENTURE LTD BERMUDA			26,500.00	628,593.41	697,480.00
	ACCOR			3,800.00	151,698.82	172,073.45
	ACCREDO HEALTH INC			33,648.00	33,108.44	1,063,613.28
	ADAPTEC INC			29,300.00	355,040.45	258,719.00
	ADC TELECOMMUNICATIONS INC			155,400.00	198,705.20	461,538.00
	ADTRAN INC			2,600.00	92,395.30	80,600.00
	ADVANTEST			1,100.00	178,856.62	87,244.56
	AEGON NV			45,602.00	1,228,954.61	674,710.88
	AEON CO LTD			14,000.00	267,589.46	468,974.53
	AFLAC INC			15,000.00	476,927.52	542,700.00
	AIFUL CORP			1,230.00	94,976.79	89,980.40
	AIR LIQUIDE(L)			1,300.00	160,410.83	229,565.81
	AIR PRODS + CHEMS INC			13,600.00	633,200.93	718,488.00
	ALBERTSONS INC			29,400.00	887,301.16	665,910.00
	ALCAN INC			2,100.00	72,821.66	98,430.64
	ALEXANDER + BALDWIN INC			5,000.00	119,011.15	168,450.00
	ALLIANCE DATA SYSTEMS CORP			37,497.00	1,063,098.57	1,037,916.96
	ALLIANZ AG			2,300.00	351,913.89	290,342.72
	ALLIED CAP CORP NEW			38,900.00	981,043.83	1,084,532.00
	ALLSTATE CORP			25,800.00	1,013,444.20	1,109,916.00
	ALTRIA GROUP INC			45,400.00	1,571,178.01	2,470,668.00
	ALUMINA LIMITED			24,000.00	50,543.87	118,804.00
	AMDOCS LTD			37,211.00	785,301.77	836,503.28
	AMERADA HESS CORP			13,700.00	802,589.02	728,429.00
	AMERICAN AXLE + MFG HLDGS INC			11,000.00	261,586.00	444,620.00
	AMERICAN ELEC PWR INC			63,960.00	2,636,802.13	1,951,419.60
	AMERICAN INTL GROUP INC			5,700.00	63,859.29	377,796.00
	AMERICAN NATL INS CO			2,541.00	132,322.58	214,384.17
	AMGEN INC			23,700.00	467,611.41	1,464,660.00
	AMSOUTH BANCORPORATION			29,700.00	636,273.90	727,650.00
	ANADARKO PETE CORP			12,700.00	613,465.88	647,827.00
	ANDREW CORP			19,700.00	240,111.97	226,747.00
	ANHEUSER BUSCH COS INC			13,700.00	544,455.34	721,716.00
	APPLIED FILMS CORP			3,900.00	94,275.89	128,778.00
	ARKANSAS BEST CORP			11,000.00	266,808.35	345,290.00
	ARM HLDGS			31,900.00	91,989.20	73,380.99

PacifiCorp Retirement Plan
Schedule H, Line 4i – Schedule of Assets (Held at End of Year)
December 31, 2003

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment Including Maturity Date, Rate of Interest, Collateral, Par or Maturity Value	(d) Cost	(e) Current Value
	ARROW INTERNATIONAL INC	8,000.00	177,729.43	199,840.00
	ARVINMERITOR INC	12,900.00	257,690.40	311,148.00
	ASML HOLDING NV	5,300.00	179,671.01	105,090.68
	ASPEN INSURANCE HOLDINGS LTD	1,600.00	36,000.00	39,696.00
	ASSA ABLOY	17,200.00	239,752.57	204,383.42
	ASTORIA FINL CORP	38,500.00	1,037,705.19	1,432,200.00
	ASTRAZENECA	32,000.00	1,371,194.53	1,535,233.76
	AT RD INC	7,700.00	98,370.36	102,410.00
	AUST + NZ BANK GRP	14,454.00	146,028.84	192,541.69
	AUTOLIV	25,900.00	498,514.62	975,135.00
	AUTOMATIC DATA PROCESSING INC	12,000.00	627,104.82	475,320.00
	AVENTIS	5,900.00	259,371.67	390,934.00
	AVIALL INC	12,100.00	97,024.60	187,671.00
	AVNET INC	28,182.00	560,176.84	610,422.12
	AXCAN PHARMA INC	13,200.00	177,831.70	206,580.00
	AZTAR CORP	16,100.00	221,479.99	362,250.00
	BAE SYSTEMS	40,736.00	116,574.68	122,693.96
	BAKER HUGHES INC	17,500.00	628,415.43	562,800.00
	BANK AMER CORP	57,400.00	3,449,722.10	4,616,682.00
	BARCLAYS	18,400.00	145,697.96	164,117.49
	BARNES + NOBLE INC	19,500.00	464,322.03	640,575.00
	BAUSCH + LOMB INC	18,000.00	890,689.91	934,200.00
	BAYERISCHE MOTOREN WERKE AG	3,000.00	110,333.20	139,063.90
	BBVA (BILB VIZ ARG)	39,900.00	500,961.51	551,090.37
	BCE INC	6,100.00	94,781.73	136,420.97
	BEAR STEARNS COS INC	15,700.00	687,529.10	1,255,215.00
	BELLSOUTH CORP	39,200.00	1,382,384.74	1,109,360.00
	BEVERLY ENTERPRISES INC	15,600.00	61,831.87	134,004.00
	BG GROUP	81,400.00	333,063.16	417,847.27
	BHP BILLITON LTD	25,979.00	110,220.91	238,605.58
	BHP BILLITON PLC	31,675.00	161,952.66	276,710.85
	BJ SVCS CO	11,650.00	416,836.36	418,235.00
	BJS WHSL CLUB INC	17,000.00	350,569.04	390,320.00
	BLACK BOX CORP	1,900.00	88,107.75	87,533.00
	BLOCKBUSTER INC	20,800.00	500,615.24	373,360.00
	BNP PARIBAS	11,700.00	480,094.78	736,709.46
	BOEING CO	12,600.00	452,543.40	530,964.00
	BOMBARDIER INC	68,800.00	160,799.88	291,225.38
	BORG WARNER INC	4,100.00	216,511.41	348,787.00
	BOSTON SCIENTIFIC CORP	29,800.00	889,834.17	1,095,448.00
	BOUYGUES	15,200.00	748,809.00	531,462.50
	BOWNE + CO INC	20,300.00	265,028.12	275,268.00
	BP PLC	12,400.00	592,611.42	611,940.00
	BRAMBLES INDUSTRIE	23,000.00	180,366.68	83,788.03
	BRIGGS + STRATTON CORP	4,800.00	236,730.32	323,520.00
	BRISTOL MYERS SQUIBB CO	13,200.00	368,201.34	377,520.00
	BROCADE COMMUNICATIONS SYS INC	27,100.00	191,717.57	156,638.00
	BRUNSWICK CORP	38,700.00	762,677.34	1,231,821.00
	BURLINGTON NORTHN SANTA FE	36,400.00	942,048.77	1,177,540.00
	C H ROBINSON WORLDWIDE	6,000.00	188,316.18	227,460.00
	C+D TECHNOLOGIES	7,300.00	102,319.73	139,941.00
	CACI INTL INC	2,500.00	127,219.79	121,550.00
	CAESARS ENTMT INC	38,800.00	298,923.74	420,204.00
	CALIPER TECHNOLOGIES CORP	14,200.00	78,090.74	93,436.00
	CALLAWAY GOLF CO	32,300.00	363,943.97	544,255.00
	CANON INC	4,000.00	167,421.66	186,246.15
	CARDINAL HEALTH INC	3,250.00	212,366.13	198,770.00
	CARREFOUR	1,600.00	80,578.76	87,830.36
	CENTERPOINT ENERGY INC	5,700.00	196,938.47	55,233.00
	CENTEX CORP	8,500.00	283,040.56	915,025.00

PacifiCorp Retirement Plan
Schedule H, Line 4i – Schedule of Assets (Held at End of Year)
December 31, 2003

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment Including Maturity Date, Rate of Interest, Collateral, Par or Maturity Value	(d) Cost	(e) Current Value
	CENTRICA	34,700.00	122,887.60	131,069.51
	CHEUNG KONG(HLDGS)	16,000.00	190,088.64	127,258.09
	CHEVRONTEXACO CORP	20,600.00	1,464,016.08	1,779,634.00
	CHICAGO BRDG + IRON CO N V	5,500.00	120,439.94	158,950.00
	CHICOS FAS INC	5,800.00	196,878.97	214,310.00
	CHUBB CORP	26,900.00	1,587,250.35	1,831,890.00
	CIGNA CORP	8,900.00	874,949.82	511,750.00
	CISCO SYS INC	108,500.00	2,046,979.02	2,635,465.00
	CITIGROUP INC	77,300.00	3,098,106.47	3,752,142.00
	COCA COLA CO	22,200.00	969,738.80	1,126,650.00
	COLGATE PALMOLIVE CO	13,900.00	617,853.75	695,695.00
	COMCAST CORP NEW	32,600.00	925,322.64	1,019,728.00
	COMERICA INC	5,000.00	290,484.79	280,300.00
	COMMERCIAL FED CORP	4,500.00	93,645.00	120,195.00
	COMMERCIAL METALS CO	25,000.00	341,878.30	760,000.00
	COMMUNITY BK SYS INC	2,700.00	121,313.36	132,300.00
	COMPASS GROUP	14,100.00	82,575.78	95,916.31
	COMPUTER SCIENCES CORP	13,900.00	423,071.88	614,797.00
	CONMED CORP	22,200.00	429,077.84	528,360.00
	CONOCOPHILLIPS	37,500.00	2,004,330.08	2,458,875.00
	CONVERGYS CORP	20,900.00	329,902.32	364,914.00
	COOPER COS INC	2,900.00	108,687.92	136,677.00
	COOPER INDUSTRIES LTD	14,700.00	620,045.14	851,571.00
	COOPER TIRE + RUBR CO	62,700.00	1,221,415.22	1,340,526.00
	COORS ADOLPH CO	6,900.00	459,082.31	387,090.00
	CORN PRODUCTS INTL INC	9,600.00	327,633.23	330,720.00
	CORNING INC	67,200.00	107,520.00	700,896.00
	CORPORATE EXECUTIVE BRD CO	4,100.00	142,297.97	191,347.00
	CORRECTIONS CORP AMER NEW	222.00	-	6,400.26
	COSTAR GROUP INC	1,600.00	61,999.17	66,688.00
	COUNTRYWIDE FINL CORP	22,400.00	643,250.34	1,699,040.00
	CRAY INC	15,999.00	138,662.99	158,870.07
	CREDIT SUISSE GRP	2,344.00	68,824.04	85,761.88
	CRH	5,044.00	97,701.19	103,386.60
	CROMPTON CORP	50,200.00	442,185.51	359,934.00
	CROWN HLDGS INC	25,900.00	746,595.51	234,654.00
	CSX CORP	19,000.00	743,048.93	682,860.00
	CTS CORP	23,300.00	373,988.72	267,950.00
	CUMMINS INC	13,100.00	488,670.42	641,114.00
	DAIMLERCHRYSLER AG	7,200.00	321,359.04	336,023.79
	DAIWA SECURITIES GROUP INC	12,000.00	104,065.51	81,627.32
	DANAHER CORP	8,200.00	596,254.84	752,350.00
	DANONE	1,760.00	188,549.29	287,265.03
	DARDEN RESTAURANTS INC	18,600.00	451,623.56	391,344.00
	DBS GROUP HLDGS	9,000.00	124,786.03	77,901.43
	DBS GROUP HLDGS LTD	13,000.00	68,191.50	112,528.00
	DELL INC	43,900.00	1,217,294.31	1,490,844.00
	DELPHI CORP	9,262.00	187,714.38	94,565.02
	DELUXE CORP	17,000.00	670,789.54	702,610.00
	DEUTSCHE BANK AG	3,800.00	232,527.52	314,908.79
	DIAGEO	11,200.00	129,807.06	147,365.26
	DIGITAS INC	14,500.00	54,988.20	135,140.00
	DIME BANCORP INC NEW	36,900.00	90,511.14	6,273.00
	DNB NOR ASA	14,500.00	70,364.55	96,771.28
	DOLLAR THRIFTY AUTOMOTIVE GRP	14,000.00	213,261.50	363,160.00
	DONNELLEY R R + SONS CO	13,600.00	338,844.00	410,040.00
	DSP GROUP INC	4,600.00	112,590.03	114,586.00
	DUN AND BRADSTREET CORP DEL	5,100.00	187,784.97	258,621.00
	DUPONT PHOTOMASKS INC	4,000.00	95,601.20	96,560.00
	DYCOM INDS INC	6,500.00	87,618.92	174,330.00
	EASTMAN CHEM CO	6,200.00	299,007.40	245,086.00

PacifiCorp Retirement Plan
Schedule H, Line 4i – Schedule of Assets (Held at End of Year)
December 31, 2003

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment Including Maturity Date, Rate of Interest, Collateral, Par or Maturity Value	(d) Cost	(e) Current Value
	EASTMAN KODAK CO	19,900.00	1,058,669.83	510,833.00
	EBAY INC	2,900.00	159,020.05	187,311.00
	EDISON INTL	50,700.00	966,073.89	1,111,851.00
	EDUCATION MGMT CORP	3,400.00	68,092.01	105,536.00
	ELECTRONIC ARTS INC	18,100.00	593,961.33	864,818.00
	ELECTRONIC DATA SYS CORP NEW	37,700.00	685,317.11	925,158.00
	EMBARCADERO TECH INC	10,100.00	156,682.61	161,095.00
	ENERGIZER HLDGS INC	14,500.00	466,329.90	544,620.00
	ENI	10,950.00	129,447.85	206,624.36
	ENTERGY CORP	14,000.00	542,560.20	799,820.00
	EQUITY INNS INC	10,900.00	94,595.52	98,645.00
	ESSILOR INTL	3,000.00	112,829.79	155,146.12
	ESTERLINE TECHNOLOGIES CORP	11,780.00	186,546.79	314,172.60
	EXELON CORP	8,000.00	383,817.76	530,880.00
	EXXON MOBIL CORP	31,200.00	1,114,642.21	1,279,200.00
	FANUC	2,800.00	162,276.37	167,733.51
	FEDERAL HOME LN MTG CORP	24,400.00	1,328,145.84	1,423,008.00
	FEDERAL NATL MTG ASSN	24,300.00	1,800,066.24	1,823,958.00
	FEDERATED DEPT STORES INC DEL	32,800.00	1,380,188.54	1,545,864.00
	FELCOR LODGING TR INC	20,800.00	343,872.48	230,464.00
	FINANZ E BREDA	74,000.00	26,093.80	-
	FINLAY ENTERPRISES INC	200.00	3,218.67	2,826.00
	FIRST ALBANY COS INC	9,700.00	113,624.02	136,188.00
	FLEETBOSTON FINL CORP	17,700.00	663,990.72	772,605.00
	FLEXTRONICS INTERNATIONAL LTD	56,300.00	826,495.54	835,492.00
	FLIR SYS INC	12,300.00	305,875.54	448,950.00
	FLOWSERVE CORP	11,500.00	159,532.23	240,120.00
	FMC CORP	22,700.00	829,008.51	774,751.00
	FOOT LOCKER INC	20,000.00	214,095.12	469,000.00
	FORENINGSSPARBK	17,300.00	263,923.39	340,215.14
	FOREST LABS INC	5,675.00	341,992.53	350,715.00
	FOSTERS GROUP	53,486.00	153,219.43	181,345.63
	FOUNDRY NETWORKS INC	13,500.00	141,674.65	369,360.00
	FRANCE TELECOM	8,500.00	196,238.62	242,948.73
	FRANKLIN RES INC	10,700.00	441,773.14	557,042.00
	FREDS INC	4,000.00	142,507.88	123,920.00
	FREEMARKETS INC	16,000.00	92,702.07	107,040.00
	FRIEDMAN BILLINGS RAMSEY GROUP	4,800.00	85,060.62	110,784.00
	FRONTIER OIL CORP	17,000.00	250,163.01	292,740.00
	FUJI PHOTO FILM CO	2,000.00	60,793.73	64,570.31
	GARDNER DENVER INC	13,000.00	222,226.08	310,310.00
	GARMIN LTD	3,600.00	98,749.29	196,128.00
	GENENTECH INC	8,100.00	325,255.50	757,917.00
	GENERAL COMMUNICATION INC	13,500.00	94,742.27	117,450.00
	GENERAL ELEC CO	135,300.00	2,810,955.40	4,191,594.00
	GENERAL MTRS CORP	17,600.00	1,210,549.29	939,840.00
	GENLYTE GROUP INC	1,900.00	84,450.00	110,922.00
	GENUINE PARTS CO	10,300.00	311,631.55	341,960.00
	GEORGIA PAC CORP	16,900.00	383,661.01	518,323.00
	GILEAD SCIENCES INC	9,350.00	531,516.76	543,609.00
	GLENBOROUGH RLTY TR INC	7,700.00	167,547.45	153,615.00
	GOLDEN WEST FINL CORP DEL	3,750.00	338,235.16	386,962.50
	GOLDMAN SACHS GROUP INC	5,600.00	493,265.03	552,888.00
	GOODRICH CORP	41,600.00	998,298.62	1,235,104.00
	GRAFTECH INTL LTD	26,500.00	413,918.56	357,750.00
	GREAT WEST LIFECO INC	1,800.00	58,429.00	63,377.83
	GREENPOINT FINL CORP	34,950.00	820,547.64	1,234,434.00
	GROUP 1 AUTOMOTIVE INC	13,600.00	510,532.04	492,184.00
	GTECH HLDGS CORP	19,700.00	209,706.50	974,953.00
	GUIDANT CORP	8,100.00	414,728.43	487,620.00
	HANG LUNG PROP	84,000.00	85,048.44	107,654.16

PacifiCorp Retirement Plan
Schedule H, Line 4i – Schedule of Assets (Held at End of Year)
December 31, 2003

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment Including Maturity Date, Rate of Interest, Collateral, Par or Maturity Value	(d) Cost	(e) Current Value
	HANG SENG BANK	6,200.00	70,092.29	81,455.48
	HARLEY DAVIDSON INC	7,000.00	303,703.43	332,710.00
	HARLEYSVILLE GROUP INC	10,000.00	159,924.64	198,900.00
	HARSCO CORP	17,500.00	591,768.87	766,850.00
	HBOS	22,600.00	248,837.70	292,709.43
	HEARTLAND EXPRESS INC	13,434.00	294,167.68	324,968.46
	HEINEKEN HOLDING	6,250.00	186,594.47	213,877.76
	HEINEKEN NV	11,150.00	437,209.35	424,593.94
	HELEN OF TROY LTD	5,800.00	133,321.80	134,270.00
	HEWLETT PACKARD CO	173,400.00	3,538,763.40	3,982,998.00
	HEXCEL CORP NEW	34,500.00	605,479.02	255,645.00
	HIBBETT SPORTING GOODS INC	5,550.00	116,791.96	165,390.00
	HIROSE ELECTRIC	2,500.00	454,841.32	286,927.31
	HOLCIM	9,090.00	462,709.29	423,354.76
	HOLOGIC INC	7,500.00	108,131.80	129,975.00
	HONG KONG LAND HLD	54,000.00	103,512.46	91,800.00
	HOT TOPIC INC	5,000.00	138,166.18	147,300.00
	HOYA CORP	2,300.00	161,469.80	211,178.50
	HSBC HLDGS	30,000.00	327,313.41	471,525.85
	HUGHES SUPPLY INC	12,500.00	312,965.03	620,250.00
	HUMAN GENOME SCIENCES INC	8,800.00	116,017.88	116,600.00
	HUTCHINSON TECHNOLOGY INC	5,800.00	134,650.11	178,292.00
	HUTCHISON WHAMPOA	9,400.00	110,123.96	69,315.73
	IMMUCOR CORP	3,600.00	46,435.75	73,404.00
	INCO LTD	3,100.00	72,423.35	123,904.04
	INDITEX	14,000.00	227,770.36	284,308.42
	INET TECHNOLOGIES INC	9,300.00	101,448.79	111,600.00
	INFINEON TECHNOLOGIES AG	7,400.00	110,729.50	102,860.62
	ING GROEP NV	17,242.00	356,868.11	402,124.34
	INGERSOLL RAND COMPANY LIMITED	4,300.00	288,671.87	291,884.00
	INGRAM MICRO INC	34,200.00	430,232.14	543,780.00
	INTEL CORP	100,700.00	3,291,082.18	3,242,540.00
	INTRAWEST CORP	6,100.00	95,490.20	112,789.00
	IOMEGA CORP	24,220.00	472,858.85	144,835.60
	J P MORGAN CHASE + CO	54,700.00	1,538,834.66	2,009,131.00
	JEFFERSON PILOT CORP	16,700.00	789,362.01	845,855.00
	JEFFRIES GROUP INC NEW	7,300.00	155,564.10	241,046.00
	JLG INDS INC	20,200.00	165,407.48	307,646.00
	JOHN HANCOCK FINANCIAL SRVCS	28,000.00	775,885.60	1,050,000.00
	JOHNSON + JOHNSON	31,275.00	1,606,766.69	1,615,666.50
	JOHNSON CTLS INC	4,700.00	411,185.49	545,764.00
	JOHNSON ELEC HLDGS	136,000.00	222,048.28	173,421.35
	KANSAI ELEC POWER	9,600.00	154,906.33	168,226.18
	KELLWOOD CO	9,937.00	186,123.59	407,417.00
	KEMET CORP	9,200.00	129,061.72	125,948.00
	KEYCORP NEW	21,100.00	524,812.12	618,652.00
	KEYENCE CORP	400.00	85,836.92	84,314.64
	KIRKLANDS INC	8,100.00	134,738.68	143,046.00
	KOGER EQUITY INC	20,000.00	365,138.55	418,600.00
	KON KPN NV	56,100.00	326,676.77	433,062.02
	LEGG MASON INC	1,700.00	91,421.53	131,206.00
	LEHMAN BROTHERS HLDGS INC	13,800.00	953,624.16	1,065,636.00
	LI + FUNG	120,000.00	208,961.98	205,570.76
	LILLY ELI + CO	11,675.00	782,634.13	821,102.75
	LINCOLN ELEC HLDGS INC	11,500.00	214,251.39	284,510.00
	LINCOLN NATL CORP IN	18,200.00	903,534.64	734,734.00
	LOEWS CORP	16,700.00	816,597.14	825,815.00
	LOREAL	2,000.00	131,024.63	163,975.58
	LOWES COS INC	18,350.00	871,744.48	1,016,406.50
	LUBRIZOL CORP	11,800.00	412,219.11	383,736.00
	MAGNA INTL INC	8,000.00	618,167.93	640,400.00

PacifiCorp Retirement Plan
Schedule H, Line 4i – Schedule of Assets (Held at End of Year)
December 31, 2003

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment Including Maturity Date, Rate of Interest, Collateral, Par or Maturity Value	(d) Cost	(e) Current Value
	MANTECH INTL CORP	4,400.00	93,325.37	109,780.00
	MANUFACTURED HOME CMNTYS INC	1,100.00	35,685.48	41,415.00
	MARATHON OIL CORP	39,700.00	994,282.94	1,313,673.00
	MARINEMAX INC	11,400.00	143,770.53	221,502.00
	MAXIM INTEGRATED PRODS INC	15,600.00	819,881.71	776,880.00
	MAXTOR CORP	32,100.00	212,603.03	356,310.00
	MAY DEPT STORES CO	16,000.00	522,539.11	465,120.00
	MCDONALDS CORP	25,700.00	643,316.79	638,131.00
	MEADWESTVACO CORP	26,800.00	597,361.41	797,300.00
	MEDIMMUNE INC	6,700.00	185,346.00	170,180.00
	MEDTRONIC INC	21,925.00	996,753.72	1,065,774.25
	MENTOR CORP MINN	9,500.00	168,196.60	228,570.00
	MERCK + CO INC	19,100.00	1,405,694.01	882,420.00
	MERRILL LYNCH + CO INC	14,700.00	707,366.08	862,155.00
	METLIFE INC	52,300.00	1,474,637.36	1,760,941.00
	METTLER TOLEDO INTL INC	4,600.00	220,414.83	194,166.00
	MICROCHIP TECHNOLOGY INC	15,650.00	435,117.20	522,084.00
	MICROSOFT CORP	104,800.00	2,144,287.93	2,886,192.00
	MICROSTRATEGY INC	1,211.00	261.55	63,553.28
	MICROSTRATEGY INC	823.00	-	205.75
	MILLEA HOLDINGS INC	14.00	172,796.99	182,887.00
	MITSUBISHI CORP	18,000.00	157,516.72	190,799.66
	MITSUBISHI ESTATE	24,000.00	253,467.52	227,526.36
	MITSUBISHI HVY IND	31,000.00	114,822.84	86,199.50
	MITSUBISHI MOTOR	62,000.00	231,900.26	126,695.90
	MITSUBISHI TOKYO FIN	11.00	64,068.27	85,807.60
	MITSUI FUDOSAN CO	15,000.00	173,802.21	135,485.68
	MITSUI SUMITOMO INSURANCE CO	29,000.00	188,514.12	238,126.34
	MKS INSTRS INC	5,800.00	137,359.93	168,200.00
	MODINE MFG CO	12,800.00	310,114.48	345,344.00
	MONRO MUFFLER BRAKE INC	6,450.00	92,308.64	129,064.50
	MONSANTO CO NEW	32,100.00	761,830.21	923,838.00
	MOOG INC	5,900.00	136,184.36	291,460.00
	MSC INDL DIRECT INC	4,000.00	74,011.52	110,000.00
	MUENCHENER RUCKVERS AG	2,057.00	275,627.81	249,392.77
	MURATA MFG CO	2,200.00	363,274.64	118,857.89
	NATIONAL CITY CORP	70,300.00	1,567,222.93	2,385,982.00
	NATIONAL GRID TRANSCO PLC	31,200.00	242,986.21	223,550.51
	NATL AUSTRALIA BK	4,400.00	79,134.44	99,289.65
	NCR CORP NEW	29,700.00	1,279,652.77	1,152,360.00
	NEC CORP	73,000.00	680,649.39	537,435.85
	NESTLE SA	2,309.00	459,027.85	576,899.94
	NETFLIX COM INC	2,700.00	56,918.89	147,663.00
	NEW CENTY FINL CORP	7,400.00	197,265.06	293,558.00
	NEWS CORPORATION	10,310.00	91,351.57	93,139.16
	NEXTEL PARTNERS INC	10,400.00	118,815.50	139,880.00
	NIDEC CORPORATION	400.00	35,007.49	38,182.33
	NIKE INC	15,300.00	897,483.22	1,047,438.00
	NIKKO CORDIAL CORP	15,000.00	83,638.03	83,558.83
	NIKON CORP	10,000.00	238,011.72	150,788.47
	NINTENDO CO	1,200.00	101,404.96	111,971.63
	NIPPON STEEL CORP	50,000.00	80,895.13	107,306.15
	NISSAN MOTOR CO	33,000.00	161,719.97	376,896.52
	NITTO DENKO CORP	5,100.00	165,495.69	271,251.28
	NOBLE CORPORATION	9,900.00	337,046.13	354,222.00
	NOKIA (AB) OY	19,800.00	660,437.45	342,403.71
	NOKIA CORP	58,500.00	724,694.49	994,500.00
	NOMURA HOLDINGS	11,000.00	192,186.88	187,319.21
	NORFOLK SOUTHN CORP	101,100.00	2,180,512.69	2,391,015.00
	NORSK HYDRO AS	5,100.00	220,477.62	314,687.05
	NORTEL NETWORKS CORP	210,300.00	276,374.98	889,569.00

PacifiCorp Retirement Plan
Schedule H, Line 4i – Schedule of Assets (Held at End of Year)
December 31, 2003

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment Including Maturity Date, Rate of Interest, Collateral, Par or Maturity Value	(d) Cost	(e) Current Value
	NORTHEAST UTILS	44,600.00	761,241.84	899,582.00
	NOVARTIS AG	17,104.00	641,215.41	776,543.04
	NOVELL INC	36,500.00	330,650.89	383,980.00
	NOVO NORDISK AS	3,200.00	111,910.64	130,371.07
	NU SKIN ENTERPRISES INC	3,800.00	43,888.10	64,942.00
	NUMICO (KON) NV	3,300.00	76,841.35	91,199.43
	OCCIDENTAL PETE CORP	77,800.00	1,673,677.56	3,286,272.00
	OGE ENERGY CORP	22,700.00	663,806.30	549,113.00
	OLD REP INTL CORP	32,100.00	705,539.48	814,056.00
	ORACLE CORP	126,000.00	2,757,777.24	1,663,200.00
	ORBITAL SCIENCES CORP	31,400.00	302,061.14	377,428.00
	ORIX CORP	3,600.00	355,840.38	297,620.60
	ORTHOFIX INTERNATIONAL NV	4,900.00	174,175.30	240,002.00
	OWENS ILL INC	51,600.00	959,216.93	613,524.00
	PACIFICARE HEALTH SYSTEMS	17,475.00	569,821.13	1,181,310.00
	PALM HBR HOMES INC	5,900.00	139,789.00	105,433.00
	PARTNERRE LTD	10,800.00	565,307.52	626,940.00
	PEABODY ENERGY CORP	8,100.00	219,090.25	337,851.00
	PEARSON	34,800.00	491,696.93	387,488.99
	PEDIATRIX MED GROUP	12,850.00	151,199.36	707,906.50
	PENN ENGR + MFG CORP	13,862.00	181,749.29	263,793.86
	PEPSICO INC	47,200.00	2,129,379.15	2,200,464.00
	PEREGRINE INVMTNT	262,000.00	415,553.41	-
	PFF BANCORP INC	10,500.00	246,942.77	380,940.00
	PFIZER INC	125,500.00	2,944,486.57	4,433,915.00
	PHILIPS ELEC(KON)	3,700.00	123,504.85	108,040.98
	PHILLIPS VAN HEUSEN CORP	14,200.00	221,589.50	251,908.00
	PHOTON DYNAMICS INC	3,900.00	121,624.82	156,936.00
	PHOTRONICS INC	5,200.00	92,061.64	103,584.00
	PLANTRONICS INC NEW	6,800.00	143,757.16	222,020.00
	PMI GROUP INC	35,000.00	777,620.34	1,303,050.00
	PNM RES INC	16,100.00	316,485.75	452,410.00
	POLARIS INDS INC	1,950.00	135,148.94	172,731.00
	POST PPTYS INC	11,500.00	415,470.55	321,080.00
	PPL CORP	25,000.00	824,421.35	1,093,750.00
	PRENTISS PPTYS TR	4,200.00	118,420.68	138,558.00
	PRIME HOSPITALITY CORP	39,400.00	478,729.38	401,880.00
	PROCTER + GAMBLE CO	13,200.00	1,212,142.50	1,318,416.00
	PROTEIN DESIGN LABS INC	6,900.00	64,890.09	123,510.00
	PROVIDIAN FINL CORP	33,600.00	335,157.38	391,104.00
	PRUDENTIAL PLC	9,900.00	128,026.74	83,694.50
	PULTE HOMES INC	16,400.00	389,082.10	1,535,368.00
	QUANEX CORP	4,100.00	117,535.52	189,010.00
	QUIKSILVER INC	11,200.00	197,932.54	198,576.00
	QWEST COMMUNICATIONS INTL INC	239,600.00	2,442,163.15	1,035,072.00
	READERS DIGEST ASSN INC	22,000.00	403,131.95	322,520.00
	RECKITT BENCKISER PLC	2,500.00	40,691.03	56,568.78
	RED HAT INC	18,800.00	155,085.54	352,876.00
	REED ELSEVIER NV	3,100.00	37,363.38	38,515.34
	REED ELSEVIER PLC	9,900.00	84,475.95	82,808.37
	REGAL BELOIT CORP	15,500.00	302,289.53	341,000.00
	REGENCY CTRS CORP	4,500.00	137,745.44	179,325.00
	RELIANCE STL + ALUM CO	12,606.00	288,528.64	418,645.26
	RENAULT (REGIE NATIONALE)	6,300.00	290,735.63	434,674.02
	RENT A CTR INC NEW	4,300.00	134,791.49	128,484.00
	REPSOL YPF SA)	4,500.00	65,046.94	87,752.16
	REYNOLDS R J TOB HLDGS INC	3,600.00	117,788.94	209,340.00
	RICHEMONT (CIE FIN)	18,142.00	397,048.95	435,672.04
	RICOH CO	5,000.00	88,186.20	98,675.00
	ROCHE HOLDINGS AG	2,725.00	285,394.55	274,868.61
	ROCK TENN CO	20,300.00	343,767.28	350,378.00

PacifiCorp Retirement Plan
Schedule H, Line 4i – Schedule of Assets (Held at End of Year)
December 31, 2003

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment Including Maturity Date, Rate of Interest, Collateral, Par or Maturity Value	(d) Cost	(e) Current Value
	ROCKWELL COLLINS INC	21,100.00	547,353.14	633,633.00
	ROHM CO	2,600.00	635,256.59	304,712.14
	ROYAL BK SCOT GRP	18,000.00	396,165.21	530,386.03
	ROYAL DUTCH PETE CO	2,200.00	102,752.22	115,258.00
	ROYAL DUTCH PETROL	20,200.00	959,410.78	1,065,033.97
	RTI INTL METALS INC	32,800.00	393,476.82	553,336.00
	RUSS BERRIE + CO INC	5,842.00	74,915.52	198,043.80
	SAFEWAY INC	13,900.00	281,540.33	304,549.00
	SANKYO CO	11,000.00	233,338.86	206,820.94
	SANOFI SYNTHELABO	18,100.00	946,220.70	1,362,977.59
	SAP AG	1,700.00	190,802.97	285,513.01
	SAP AKTIENGESELLSCHAFT	15,400.00	378,207.54	640,024.00
	SAPIENT CORP	20,600.00	113,095.54	115,360.00
	SBC COMMUNICATIONS INC	24,568.00	1,145,651.68	640,487.76
	SBS TECHNOLOGIES INC	18,500.00	239,990.60	272,135.00
	SCHEIN HENRY INC	5,100.00	241,204.90	344,658.00
	SCHNEIDER ELECTRIC	2,400.00	115,825.44	157,113.83
	SCHWEITZER MAUDUIT INTL INC	11,600.00	289,997.18	345,448.00
	SEACHANGE INTL INC	10,100.00	147,737.38	155,540.00
	SEACOR SMIT INC	7,700.00	328,672.00	323,631.00
	SEARS ROEBUCK + CO	39,900.00	1,335,621.94	1,815,051.00
	SEKISUI HOUSE	21,000.00	159,029.91	216,917.05
	SELECT COMFORT CORP	6,800.00	168,136.88	168,368.00
	SELECT MED CORP	154,870.00	1,478,732.98	2,521,283.60
	SEMPRA ENERGY	41,900.00	1,045,918.37	1,259,514.00
	SES GLOBAL	10,600.00	117,550.83	106,962.53
	SHIMAMURA CO	1,200.00	67,936.77	81,515.35
	SHIN ETSU CHEM CO	2,500.00	102,407.54	102,174.12
	SHIONOGI + CO	14,000.00	233,012.68	260,744.61
	SHUFFLE MASTER INC	3,600.00	71,392.05	124,632.00
	SIEMENS AG NPV (REGD)	5,000.00	269,013.52	400,478.81
	SILICON LABORATORIES INC	2,800.00	145,297.36	121,016.00
	SINGAPORE AIRLINES	13,000.00	85,468.56	85,732.79
	SINGAPORE TECH ENG	56,000.00	82,651.47	67,267.27
	SINGAPORE TELECOMM	521,760.00	564,273.69	602,160.75
	SMC CORP	1,200.00	135,547.84	149,370.16
	SMITH + NEPHEW	13,000.00	82,476.88	109,203.70
	SMITHS GROUP	32,246.00	437,587.76	381,563.70
	SMURFIT STONE CONTAINER CORP	75,400.00	1,107,549.14	1,400,178.00
	SOC GENERALE	1,200.00	83,439.30	105,953.45
	SOLECTRON CORP	98,900.00	638,669.24	584,499.00
	SOMPO JAPAN INS	7,900.00	65,152.53	64,942.61
	SONIC AUTOMOTIVE INC	13,000.00	203,425.50	297,960.00
	SONY CORP	3,800.00	318,240.15	131,548.01
	SPRINT CORP	210,600.00	2,812,159.12	2,756,052.00
	ST JUDE MED INC	18,100.00	1,089,046.03	1,110,435.00
	ST MARY LD + EXPL CO	3,700.00	77,047.47	105,450.00
	STANCORP FINL GROUP INC	6,500.00	310,490.05	408,720.00
	STANDARD CHARTERED	21,400.00	248,881.20	353,402.72
	STARBUCKS CORP	32,000.00	827,008.06	1,057,920.00
	STATOIL ASA	29,100.00	213,284.75	326,963.83
	STMICROELECTRONICS	900.00	18,878.84	24,407.13
	STMICROELECTRONICS N V	5,800.00	219,510.43	156,658.00
	STORAGE TECHNOLOGY CORP	39,400.00	552,340.50	1,014,550.00
	STRYKER CORP	4,400.00	279,673.91	374,044.00
	SUMITOMO CHEMICAL	28,000.00	103,245.61	115,480.08
	SUMMIT PPTYS INC	15,600.00	360,734.51	374,712.00
	SUN CMNTYS INC	200.00	7,902.47	7,740.00
	SUN HUNG KAI PROPS	9,000.00	61,818.27	74,480.76
	SUNCOR ENERGY INC	3,400.00	54,406.01	85,509.77
	SUNOCO INC	8,500.00	321,701.72	434,775.00

PacifiCorp Retirement Plan
Schedule H, Line 4i – Schedule of Assets (Held at End of Year)
December 31, 2003

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment Including Maturity Date, Rate of Interest, Collateral, Par or Maturity Value	(d) Cost	(e) Current Value
	SUPERVALU INC	61,000.00	1,197,572.40	1,743,990.00
	SUZUKI MOTOR CORP	23,000.00	308,210.53	340,375.10
	SVENSKA HANDELSBANKEN SERIES A	4,700.00	65,629.04	96,021.01
	SWIRE PACIFIC	17,500.00	109,040.80	107,969.73
	SWISS REINSURANCE	9,204.00	876,654.10	621,414.19
	SWISSCOM AG	1,435.00	443,256.07	473,402.06
	SYNTHES STRATEC	121.00	72,321.52	119,752.58
	SYSCO CORP	15,000.00	369,366.00	558,450.00
	TAIYO YUDEN CO	5,000.00	255,850.70	65,363.44
	TBC CORP	7,300.00	125,038.96	188,413.00
	TELECOM CORP OF NZ	24.00	50.75	84.62
	TELEFONICA SA	24,702.00	252,267.40	362,677.75
	TELLABS INC	108,900.00	1,049,236.69	918,027.00
	TELUS CORP	6,200.00	40,597.48	116,107.56
	TEREX CORP NEW	20,800.00	345,182.37	592,384.00
	TESORO PETE CORP	16,200.00	181,767.28	236,034.00
	TEVA PHARMACEUTICAL INDS LTD	11,650.00	357,497.25	660,671.50
	TEXAS INDS INC	12,700.00	443,844.70	469,900.00
	TEXTRON INC	13,600.00	677,195.44	776,016.00
	THOMAS + BETTS CORP	11,200.00	359,535.16	256,368.00
	THOMSON CORP	14,400.00	402,188.73	524,629.14
	TI AUTOMOTIVE	30,100.00	-	-
	TIBCO SOFTWARE INC	17,100.00	105,698.10	115,767.00
	TIDEWATER INC	4,300.00	139,801.38	128,484.00
	TIMCO AVIATION SVCS INC	324.00	-	246.25
	TIMCO AVIATION SVCS INC	1,035.00	-	0.10
	TOKYO ELECTRON	7,100.00	754,708.74	539,274.05
	TORAY INDS INC	20,000.00	86,233.43	83,605.49
	TOYOTA MOTOR CORP	6,000.00	186,185.80	202,668.66
	TPG NV	3,500.00	79,886.15	81,981.48
	TRAVELERS PPTY CAS CORP NEW	27,137.00	442,024.33	455,542.59
	TRIAD HOSPS INC	6,688.00	16,284.00	222,509.76
	TRIBUNE CO NEW	10,700.00	496,178.44	552,120.00
	TRIMBLE NAVIGATION LTD	5,200.00	86,200.98	193,648.00
	TULARIK INC	6,300.00	100,367.09	101,745.00
	TYSON FOODS INC (DEL)	51,115.00	436,709.99	676,762.60
	UBS AG	4,594.00	225,549.32	314,624.46
	UNICREDITO ITALIAN	16,000.00	78,687.50	86,377.29
	UNILEVER	37,400.00	295,322.32	348,650.76
	UNILEVER NV	1,300.00	69,006.68	85,021.34
	UNION PAC CORP	6,100.00	359,901.22	423,828.00
	UNIONBANCAL CORP	24,700.00	885,050.16	1,421,238.00
	UNISOURCE ENERGY CORP	17,100.00	285,753.85	421,686.00
	UNIT CORP	7,600.00	112,834.82	178,980.00
	UNITED PARCEL SVC INC	13,700.00	771,120.81	1,021,335.00
	UNITED SURGICAL PARTNERS	39,016.00	660,453.73	1,306,255.68
	UNITED TECHNOLOGIES CORP	19,500.00	1,366,679.76	1,848,015.00
	UNIVERSAL CORP VA	17,600.00	608,792.49	777,392.00
	UNIVERSAL DISPLAY CORP	10,400.00	109,397.07	142,168.00
	UNIVERSAL HEALTH SVCS INC	7,200.00	272,269.51	386,784.00
	UPM KYMMENE OY	7,354.00	110,247.97	140,252.70
	URS CORP NEW	9,700.00	231,643.80	242,597.00
	USF CORP	2,300.00	61,396.99	78,637.00
	VALERO ENERGY CORP	23,100.00	602,538.84	1,070,454.00
	VENTURE CORP LTD	9,000.00	72,000.14	105,988.34
	VERITAS SOFTWARE CORP	23,025.00	1,211,136.71	855,609.00
	VERIZON COMMUNICATIONS	40,200.00	1,752,665.46	1,410,216.00
	VIACOM INC	28,000.00	1,212,705.48	1,242,640.00
	VISHAY INTERTECHNOLOGY INC	10,640.00	161,308.88	243,656.00
	VISTEON CORP	2,782.00	48,122.72	28,960.62
	VIVENDI UNIVERSAL	13,200.00	361,227.43	320,842.18

PacifiCorp Retirement Plan
Schedule H, Line 4i – Schedule of Assets (Held at End of Year)
December 31, 2003

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment Including Maturity Date, Rate of Interest, Collateral, Par or Maturity Value	(d) Cost	(e) Current Value
	VNU NV	4,049.00	177,659.00	127,935.57
	VODAFONE GROUP	638,761.00	1,963,474.80	1,583,718.18
	VODAFONE GROUP PLC NEW	38,000.00	1,190,079.41	951,520.00
	WACHOVIA CORP 2ND NEW	45,900.00	1,618,625.44	2,138,481.00
	WAL MART STORES INC	37,000.00	2,078,854.25	1,962,850.00
	WALGREEN CO	31,050.00	465,841.16	1,129,599.00
	WASHINGTON FED INC	11,107.00	198,840.08	315,438.80
	WASHINGTON MUT INC	54,500.00	1,703,048.00	2,186,540.00
	WATSCO INC	7,800.00	166,821.92	177,294.00
	WEBEX COMMUNICATIONS	8,600.00	129,836.46	172,860.00
	WESFARMERS	2,100.00	38,140.54	41,913.67
	WEST MARINE INC	5,900.00	115,642.34	164,079.00
	WESTERN DIGITAL CORP	44,800.00	499,065.31	528,192.00
	WHIRLPOOL CORP	27,000.00	1,403,653.95	1,961,550.00
	WISCONSIN ENERGY CORP	24,400.00	637,581.76	816,180.00
	WMC RESORCES LTD	24,000.00	39,874.51	101,806.17
	WOLVERINE TUBE INC	23,200.00	343,143.99	146,160.00
	WOOLWORTHS LTD	10,300.00	55,043.54	91,574.32
	WPS RES CORP	5,200.00	176,435.48	240,396.00
	WYETH	57,700.00	2,673,520.27	2,449,365.00
	XSTRATA	15,750.00	126,958.67	177,627.76
	YAHOO INC	29,000.00	1,174,145.92	1,309,930.00
	YAHOO JAPAN CORP	14.00	121,366.06	188,112.34
	YAMATO TRANSPORT	5,000.00	65,414.25	58,878.42
	YORK INTL CORP	15,800.00	550,040.29	581,440.00
	ZALE CORP NEW	1,700.00	81,719.00	90,440.00
	ZYGO CORP	5,500.00	107,838.99	90,695.00
	Total common stock		**251,174,784.08**	**293,274,031.75**
Mutual funds				
	CAP GUARD EMERGING MKTS EQUITY	425,947.77	2,435,829.90	2,781,438.96
	EMERGING MKTS GROWTH FD INC	228,492.01	12,542,603.24	13,958,576.83
	NTGI QM COLLECTIVE DAILY	18,334.56	43,222,203.77	52,222,657.27
	PROGRESS ENERGY INC	17,000.00	-	-
	SSGA PASSIVE BD MKT INDX SL FD	4,614,053.47	65,504,613.92	78,609,628.92
	THE BOSTON COMPANY	5,054,649.19	47,974,680.86	62,819,180.16
	Total mutual funds		**171,679,931.69**	**210,391,482.14**
Investment of securities lending collateral				
*	STATE STREET NAVIGATOR SECURITIES LENDING PRIME PORTFOLIO		**33,067,927.00**	**33,067,927.00**
Limited partnership units				
	ADVANCED TECHNOLOGY		5,377,250.76	1,562,231.00
	ADVANCED TECHNOLOGY VENT VI LP		8,063,283.60	3,232,140.00
	ADVANCED TECHNOLOGY VENTURES V		9,897,075.64	3,852,779.00
	APOLLO ADVISORS IV LP		17,630,867.61	20,057,544.00
	BRAND EQUITY VENTURES I		9,467,240.98	2,161,755.00
	BRAND EQUITY VENTURES II		4,000,000.00	2,209,055.00
	BRAZOS FUND LP		-	12,980.00
	CORTEC INVESTMENT II		9,398,823.00	1,654,575.00
	HARBOURVEST INTL PTNR III PART		12,468,046.15	10,917,295.00
	INFINITY CAPITAL LP		8,803,663.00	1,199,535.00
	INFORMATION TECH VENTURES II		9,171,946.04	1,204,377.00
	INFORMATION TECH VENTURES LP		2,885,980.08	2,514,539.00
	LONE STAR FUND II		2,481,940.56	4,145,000.00
	LONE STAR FUND III		9,316,339.93	19,061,000.00
	LONE STAR OPPORTUNITY FD LP		5,255,061.51	5,573,000.00
	NEW ENTERPRISE ASSOC L. P.		2,156,563.41	366,907.00
	WELSH CARSON ANDERSON + STOWE		7,324,672.10	4,539,009.00
	WILLIS STEIN + PARTNERS		3,132,266.00	2,622,966.00
	Total limited partnership units		**126,831,020.37**	**86,886,687.00**
	Total investments		**$ 766,825,099.63**	**$ 817,864,948.81**

* Indicates party-in-interest.

PacifiCorp Retirement Plan
Schedule H, line 4j – Schedule of Reportable Transactions
Year Ended December 31, 2003

(a)	(b)	(c)	(d)	(g)	(h)	(i)
Identity of party involved	Description of asset	Purchase price	Selling price	Cost of asset	Current value of asset on transaction date	Net gain or (loss)
PacifiCorp Sweep Fund	Short -term investment	$ 58,446,118		$ 58,446,118	$ 58,446,118	
PacifiCorp Sweep Fund	Short -term investment		$ 55,553,203	55,553,203	55,553,203	$ -
State Street Bank & Trust Company	Short -term investment	217,722,283		217,722,283	217,722,283	
State Street Bank & Trust Company	Short -term investment		208,306,091	208,306,091	208,306,091	-
Julius Baer	Common stock		53,670,211	51,722,229	53,670,211	1,947,982
Rogge	Common stock		34,839,571	32,334,387	34,839,571	2,505,184
NTGI QM Collective Daily	Mutual Fund		51,375,157	58,930,750	51,375,157	(7,555,593)
SSGA Funds	Mutual Fund		62,578,106	76,697,688	62,578,106	(14,119,582)
SSGA Passive Bond Market Index	Mutual Fund	76,021,476		76,021,476	76,021,476	

Information certified as complete and accurate by State Street Bank & Trust Company and Deutsche Bank Trust Company Americas.

UE-170/PacifiCorp
April 22, 2005
ICNU 19th Set Data Request 19.4

ICNU Data Request 19.4

Mr. Rosborough's testimony on page 6 describes IBEW 57 pension expense.

a. What would be the size of the contributions to IBEW pension if it is assumed that the contribution is 7% of the eligible pay?
b. Has the Company made its $3 million contribution in 2005?
c. Please provide the most recent estimate of the contribution that PacifiCorp will have to make to the IBEW pension expense in 2006.

Response to ICNU Data Request 19.4

a. If contributions returned to the 7% of pay level, amounts expected to be contributed during 2005 and 2006 would be $6.44M and $6.65M.

b. The company did not make a contribution in 2005, pursuant to negotiations with Local 57.

Please see Attachment ICNU 19.4, the Memorandum of Agreement between the Company and the Union, on the enclosed CD.

c. Actual negotiations with the union will not take place until early 2006. At this time, we expect that a contribution between $3 million and $6 million will be the result of those negotiations.

OREGON

2004 GENERAL RATE CASE

UE-170

PACIFICORP

ICNU 19th SET DATA REQUEST

ATTACHMENT ICNU 19.4

ON THE ENCLOSED CD

Memorandum of Agreement

between

Local 57 IBEW & PacifiCorp
March 9, 200~~4~~5

Issue: Fiscal Year 2005 Funding to the PacifiCorp/Local 57 IBEW Retirement Trust

Per the terms of the current collective bargaining agreement, PacifiCorp and Local 57 IBEW have met and discussed fiscal year 2005 funding for the PacifiCorp/Local 57 IBEW Retirement Trust (Trust). The parties have agreed that:

1. The actuarial valuation for the Trust establishes that an ERISA Minimum Contribution is not required for the Plan year commencing July 1, 2004.

2. The investment results within the Trust during calendar year 2004 have been sufficient to eliminate the need for a cash contribution from PacifiCorp for 2004, and;

3. The parties will meet in the 1st calendar quarter of 2006, (PacifiCorp's 4th fiscal quarter) to negotiate the appropriateness of any contribution requirement for fiscal year 2006.

Byron Nielsen
Business Manager, Local 57 IBEW

Fred Horvath
Managing Director, Labor & Employee Relationships
PacifiCorp

PACIFICORP – OREGON

Pension and Other Post Retirement Expense

Line	Description	Amount (000)	Amount (000)
1	2004 Pension Expense	$31,200	
2	Discount Rate Adjustment	$4,300	
3	Test Year Pension Expense		$27,200
4	IBEW Pension Contribution		$1,500
5	2004 OPEB Expense	$21,000	
6	Discount Rate Adjustment	$2,900	
7	Test Year OPEB Expense		$18,100
8	Total		$46,800
9	PacifiCorp's Test Year Pension Expense	$42,200	
10	IBEW Pension Contribution	$3,000	
11	OPEB Expense	$26,800	
12	Total		$72,000
13	Reduction from Company		$25,200
14	Oregon System Overhead Allocation (Line 13 X 29.446%)		$7,420
15	Expense Reduction (Line 14 X 74.63%)		$5,538

UE-170/PacifiCorp
April 19, 2005
ICNU 16th Set Data Request 16.19

ICNU Data Request 16.19

Please provide the amounts for buildings and other depreciable assets, land and accumulated depreciation at the end of the most current fiscal year for each entity listed in the consolidated tax return.

Response to ICNU Data Request 16.19

Please see Attachment ICNU 16.19 on the enclosed CD.

OREGON

2004 GENERAL RATE CASE

UE-170

PACIFICORP

ICNU 16th SET DATA REQUESTS

ATTACHMENT ICNU 16.19

ON THE ENCLOSED CD

OR GRC UE-170 / PacifiCorp
List of companies filing Federal Corporate Income tax Returns
ICNU Data Request 16.19
Attachment ICNU DR 16.19

$ = 000's

Based on 3/31/04 Tax Return Ending Balance Sheet

Consolidated Group	Buildings & Depr. Assets	Accum Depreciation	Net Book Value	Land	Total Net Book Value
PacifiCorp	13,208,525	(4,654,842)	8,553,683	90,058	8,643,741
Centralia Mining Company			-		-
Energy West Mining Company			-		-
Interwest Mining Company			-		-
Pacific Minerals, Inc.	260,999	(136,717)	124,282		124,282
Non-Regulated Companies	215,099	130,321	345,420	12,038	357,458
Grand Total	13,684,623	(4,661,238)	9,023,385	102,096	9,125,481

UE-170/PacifiCorp
April 22, 2005
ICNU 19th Set Data Request 19.3

ICNU Data Request 19.3

In PacifiCorp's most recent rate case in the State of Washington, Docket No. UE-032065, Account 923 included RTO development costs of $3.524 million. Please identify all RTO development costs that are included in the test year as an expense and identify the account in which those costs appear.

Response to ICNU Data Request 19.3

Please refer to Attachment ICNU 19.3 on the enclosed CD.

OREGON

2004 GENERAL RATE CASE

UE-170

PACIFICORP

ICNU 19th SET DATA REQUEST

ATTACHMENT ICNU 19.3

ON THE ENCLOSED CD

UE-170 / PacifiCorp
ATTACHMENT ICNU 19.3
GRID WEST COSTS

Category	FERC Account	FY '04 $$$	FY '05 DRI	FY '05 $$$	FY '06 DRI	FY '06 $$$	Apr - Dec '06 DRI	Apr - Dec '06 $$$	Allocation Code
Bonus/Incentive	920	2,611	1.030	2,689	1.030	2,769	1.0239	2,836	SO
Other Salary/Labor	920	9,314	1.030	9,593	1.030	9,881	1.0239	10,117	SO
Salary Expense		**11,924**		**12,282**		**12,650**		**12,953**	
Project	922	487,255	1.030	501,873	1.030	516,929	1.0239	529,284	SO
Administ	922	223,500	1.030	230,205	1.030	237,111	1.0239	242,778	SO
Process	922	106,664	1.030	109,864	1.030	113,159	1.0239	115,864	SO
Finance Analyst	922	5,832	1.030	6,007	1.030	6,187	1.0239	6,335	SO
Appl Development	922	1,808	1.030	1,862	1.030	1,918	1.0239	1,963	SO
Director	922	658,969	1.030	678,738	1.030	699,100	1.0239	715,808	SO
Secondary Salary Expense		**1,484,027**		**1,528,547**		**1,574,404**		**1,612,032**	
Oth Salary Overhd	920	(75,933)	1.030	(78,211)	1.030	(80,558)	1.0239	(82,483)	SO
Salary Overhead/Benefits		**(75,933)**		**(78,211)**		**(80,558)**		**(82,483)**	
Total Labor Expense		**1,420,017**		**1,462,618**		**1,506,497**		**1,542,502**	
Airfare	921	33,214	1.038	34,477	1.035	35,684	1.0239	36,536	SO
Lodging	921	19,795	1.038	20,548	1.035	21,267	1.0239	21,775	SO
On-Site Meals & Refreshment	921	848	1.038	880	1.035	911	1.0239	933	SO
Meals/Entertain	921	10,009	1.038	10,390	1.035	10,753	1.0239	11,010	SO
Vehicle Rent/Exp	921	4,637	1.038	4,813	1.035	4,982	1.0239	5,101	SO
Other Ground Tran	921	1,774	1.038	1,841	1.035	1,905	1.0239	1,951	SO
Auto/Park/Mileage	921	5,285	1.038	5,486	1.035	5,678	1.0239	5,814	SO
Cell Phone	921	4,513	1.038	4,685	1.035	4,849	1.0239	4,965	SO
503145 OLEE Telephone Ex	921	311	1.038	323	1.035	334	1.0239	342	SO
Registration	921	9,865	1.038	10,240	1.035	10,599	1.0239	10,852	SO
Dues & Licenses	921	5,944	1.038	6,170	1.035	6,386	1.0239	6,539	SO
Books & Subscript	921	215	1.038	223	1.035	231	1.0239	237	SO
Other Emp Rel Expense	921	3,364	1.038	3,492	1.035	3,614	1.0239	3,700	SO
Employee Expenses		**99,773**		**103,568**		**107,193**		**109,755**	
Computer Hardware	935	532	1.038	553	1.035	572	1.0239	586	SO
Comp Software/Lic	935	718	1.038	746	1.035	772	1.0239	790	SO
Office Supplies	921	3,968	1.038	4,119	1.035	4,263	1.0239	4,365	SO
Misc M&S	935	729	1.038	757	1.035	784	1.0239	802	SO
Materials & Supplies		**5,948**		**6,175**		**6,391**		**6,543**	
Acct/Tax Prof Ser	923	6,441	1.038	6,686	1.035	6,920	1.0239	7,085	SO
Printing/Imaging	921	6,423	1.038	6,667	1.035	6,901	1.0239	7,066	SO
Consult-Tech Services	923	577,174	1.038	599,129	1.035	620,096	1.0239	634,916	SO
Legal Fees/Services	923	715,323	1.038	742,533	1.035	768,518	1.0239	786,886	SO
Mov/Relo Serv-Emp	921	18,126	1.038	18,815	1.035	19,474	1.0239	19,939	SO
Temp Services-Oth	923	32	1.038	34	1.035	35	1.0239	36	SO
Training/Edu Services	921	3,000	1.038	3,114	1.035	3,223	1.0239	3,300	SO
Misc Contr/Services	923	11,376	1.038	11,809	1.035	12,222	1.0239	12,514	SO
Primary Contracts & Servi		**1,337,895**		**1,388,788**		**1,437,389**		**1,471,742**	
Telephone	921	(44)	1.038	(46)	1.035	(48)	1.0239	(49)	SO
Utilities		**(44)**		**(46)**		**(48)**		**(49)**	
Total	Total	**2,863,589**		**2,961,103**		**3,057,421**		**3,130,493**	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 170

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

DIRECT TESTIMONY OF

KATHRYN E. IVERSON

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

MAY 9, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Kathryn E. Iverson, 17244 W. Cordova Court, Surprise, Arizona, 85387.

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

A. I am a consultant in the field of public utility regulation and employed by the firm of Brubaker & Associates, Inc. ("BAI"), regulatory and economic consultants with corporate headquarters in St. Louis, Missouri.

Q. WOULD YOU PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE?

A. I have a Bachelor of Science Degree in Agricultural Sciences and a Master of Science Degree in Economics from Colorado State University. I have been a consultant in this field since 1984, with experience in utility resource matters, cost allocation and rate design. More details are provided in Exhibit ICNU/301.

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

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association, whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including PacifiCorp (or the "Company").

Q. WHAT SUBJECTS DO YOU ADDRESS IN THIS TESTIMONY?

A. I have been asked to review PacifiCorp's marginal cost study and proposed rate design. I will make recommendations to the Oregon Public Utility Commission ("Commission") on the proposed marginal cost study, rate spread, and rate design.

Q. WHAT SPECIFIC AREAS DOES YOUR TESTIMONY COVER?

A. My testimony reviews the reconciliation of marginal costs to embedded costs, and provides recommended relative base rate increases necessary to move rates closer to cost of service.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibits ICNU/301 through ICNU/305. These exhibits were prepared either by me or under my supervision and direction.

Q. WHAT INCREASE DOES PACIFICORP SEEK FROM SCHEDULE 48 CUSTOMERS?

A. While the Company is seeking an overall increase of 12.5% increase in base rates, the proposed increase to Schedule 48 customers is 21.6%. PPL/1202, Griffith/1, column 13, line 6. This increase is the second highest to a single class, and represents a substantial increase in costs to ICNU members.

Q. WOULD YOU PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS?

A. The main points of my testimony can be summarized as follows:

- PacifiCorp's marginal cost study classifies 71% of the generation revenue requirement on the basis of energy, as compared to the jurisdictional study, which classifies 51%. For transmission, the marginal study classifies 47% on the basis of energy, as compared to the jurisdictional study, which classifies 26%. This added focus on energy penalizes larger, higher load factor customers.
- By focusing so heavily on energy, PacifiCorp's marginal study minimizes the economic consequences of both the timing of incremental energy use and the growth in peak demands. Marginal cost studies that minimize demand costs can

result in price signals with no relationship to cost differentials that exist in the marketplace.

- The current marginal cost study reconciles marginal cost to the target revenue requirement on a functional basis that ignores the underlying energy and demand classifications. An improvement would be to reconcile the functional marginal costs to their respective demand and energy classifications.
- I agree with the Company's overall objective on rate spread where none of the major rate schedules will see an overall net rate increase greater than approximately 1.5 times the overall average net.
- Distribution and non-Federal Energy Regulatory Commission ("FERC") related transmission costs should be recovered through the On-Peak Demand charge for Schedule 48.
- The proposed time-of-day pricing for Schedule 200 service to large power customers should be rejected. Since the underlying cost study has no recognition of cost differentials, this proposal is simply a rate design strategy to boost revenues for energy sold to large power users during on-peak times. Customers who shift usage to off-peak times, however, will see no benefit in subsequent revenue allocation since the Company's cost study makes no distinction between on-peak and off-peak energy usage.

Q. HAVE YOU REVIEWED PACIFICORP'S MARGINAL COST OF SERVICE STUDY CONTAINED IN THE TESTIMONY OF MR. DAVID TAYLOR?

A. Yes, I have. Mr. Taylor presents the results of a marginal cost study and the development of unbundled class revenue requirements in PPL/409. According to the Company's cost study, Schedule 48T secondary rates should be increased by 18.76%, primary rates by

22.12% and transmission rates by 25.71%, for a total base rate increase of 21.6% to Schedule 48T. In contrast, the overall base rate increase for all classes is 12.48%.

Q. WHY IS THE INCREASE TO SCHEDULE 48T CUSTOMERS SO MUCH HIGHER THAN FOR THE OTHER SCHEDULES?

A. The above average increase is a result of a marginal cost study which allocates the bulk of generation and transmission costs on the basis of energy usage. Since generation and transmission costs represent the greatest component of large power users' costs, and since Schedule 48T customers are energy-intensive, this allocation method results in substantially more costs allocated to this class.

Q. IS THIS A RESULT OF THE REVISED PROTOCOL?

A. No, it is not. Under the Revised Protocol, which dictates the allocation of costs among PacifiCorp's jurisdictions, the bulk of the generation and transmission costs are classified and allocated on the basis of demand, and not on energy. All Resource Fixed Costs, Wholesale Contracts and Short-term Purchases and Sales are classified as 75 percent demand related and 25 percent energy related in the Jurisdictional Allocation Model. PPL/400, Taylor/4.

Q. PLEASE EXPLAIN HOW YOUR PROPOSALS WOULD IMPACT RATES.

A. Using PacifiCorp's requested revenue requirement and my recommendation for rate allocation and rate spread, the following table compares PacifiCorp's and ICNU's changes in both base rates and net rates for illustrative purposes. Under ICNU's proposal, Schedule 48 would receive a base rate increase of 18.6%, and with inclusion of all proposed riders a net rate increase of 5.2%. This compares to PacifiCorp's request for a base rate increase of 21.6% and net rate increase of 8.0%. Classes with net rate increases of 9.9% under PacifiCorp's proposal would be similarly treated under ICNU's proposal as a result of our consistent objective for none of the major rate schedules to experience an overall net rate increase greater than 1.5 times the overall average net increase proposed in this case. Residential customers would receive a slightly higher net rate increase of 9.2% compared to PacifiCorp's request for 8.4%. Schedules 28 and 30 would receive net rate increases of under 2% under either proposal.

	Base Rate Changes		Net Rate Changes	
	PacifiCorp	ICNU	PacifiCorp	ICNU
Residential:				
Schedule 4	10.4%	11.2%	8.4%	9.2%
Commercial & Industrial:				
Schedule 23	25.4%	27.4%	9.9%	9.9%
Schedule 28	3.0%	3.0%	1.0%	1.8%
Schedule 30	9.5%	9.7%	1.3%	1.9%
Schedule 48	21.6%	18.6%	8.0%	5.2%
Schedule 41	18.3%	18.9%	9.9%	9.9%
Lighting	-2.8%	-9.3%	3.4%	3.5%
Total	12.5%	12.5%	6.7%	6.7%

I. MARGINAL COSTS OF GENERATION AND TRANSMISSION

Q. HOW ARE GENERATION MARGINAL COSTS DETERMINED IN THE MARGINAL COST STUDY?

A. PacifiCorp calculates separate demand and energy-related marginal costs for generation in its marginal cost study. The marginal demand and energy costs for generation are based on a hypothetical system where equipment is of the minimum size necessary to meet the load. The demand-related marginal cost of generation is defined as the fixed cost of a simple cycle combustion turbine. Fixed costs for a combined cycle combustion turbine which are in excess of the demand costs of a simple cycle turbine are assigned to energy and are added to the variable production cost of the combustion cycle turbine. The long-run marginal costs of generation used by PacifiCorp in this case are **$69.33 per kW-year** for demand, and **$27.22 per MWH** for energy.

Q. WHAT ARE THE RESULTS OF APPLYING THESE GENERATION MARGINAL COSTS TO CLASS LOADS?

A. Applying the generation marginal costs to the class loads results in total generation marginal cost of $552 million. Of that amount, 71% is classified and allocated to customers on the basis of energy.

Demand: $69.33 x Peak Demands =	$157,353,000	29%
Energy: $27.22 x Energy at Generation =	$394,480,000	71%
Total:	$551,833,000	100%

Q. HAS PACIFICORP RECOGNIZED THE IMPLICATIONS OF THIS HIGH LEVEL OF ENERGY COMPONENT IN GENERATION MARGINAL COSTS?

A. Yes. In UE 147, Mr. Taylor noted that this high level of energy costs was shifting a larger share of generation costs to larger, higher load factor customers:

> The energy component of generation marginal costs increased from 69% of total generation costs in UE 116 to 77% in the current [UE 147] study . . . This increased energy component shifted a larger portion of generation costs to larger, higher load factor customers.

Re PacifiCorp, OPUC Docket No. UE 147, PPL/1100, Taylor/6.

Q. HOW DOES THE COMPANY CLASSIFY AND ALLOCATE TRANSMISSION COSTS IN ITS MARGINAL COST STUDY?

A. Growth-related investments in transmission, except bulk power lines, are classified entirely to demand. Bulk power lines are classified to demand and energy in the same proportions as PacifiCorp's proposed generation costs. Consequently, any increase in the energy component of generation marginal costs will cause the energy component of transmission marginal costs to increase as well. The long-run marginal costs of transmission used by PacifiCorp in this case are **$12.85 per kW-year** for demand, and **$1.75 per MWH** for energy.

Q. WHAT ARE THE RESULTS OF APPLYING THESE TRANSMISSION MARGINAL COSTS TO CLASS LOADS?

A. Applying the transmission marginal costs to the class loads results in a total transmission marginal cost of $55 million. Of that amount, 47% is classified and allocated to customers on the basis of energy.

Demand: $12.85 x Peak Demands =	$29,165,000	53%
Energy: $1.75 x Energy at Generation =	$25,381,000	47%
Total:	$54,546,000	100%

Q. HOW DO PACIFICORP'S MARGINAL COST ENERGY COMPONENTS (GENERATION AT 71% AND TRANSMISSION AT 47%) COMPARE TO THE TARGET GENERATION REVENUE REQUIREMENT?

A. These marginal cost energy components are significantly higher than what is reflected in Oregon's jurisdictional revenue requirement. For example, the Company seeks a target revenue requirement of $524 million for generation, of which $180 million is for energy-related production expenses such as fuel and purchased energy.[1/] Of the remaining amount, the Revised Protocol classifies 75% as demand-related and 25% as energy-related. As shown in Exhibit ICNU/302, when the 75/25 split is applied to the remaining $344 million generation revenue requirement target, Oregon's generation is 51% energy-related overall, not 71% as the marginal cost study assumes. For transmission, Oregon's transmission revenue requirement target is only 26% energy-related. Because of this greater emphasis on energy, the marginal cost study penalizes larger, higher load factor customers in the determination of both generation and transmission revenues.

1/ This is PacifiCorp's proposed target revenue requirement for the generation function. The amount actually allowed by the Commission may be substantially less than the filed request.

Q. DOES THE GREATER EMPHASIS ON ENERGY IN THE MARGINAL COST STUDY COMPARED TO THE TARGET REVENUE REQUIREMENT PRESENT ALLOCATION ISSUES AMONG THE CLASSES?

A. Yes, it does. By focusing so heavily on energy, the present approach minimizes the economic consequences of both the timing of the incremental energy use and the growth in peak demands. While it is important to give customers a price signal of the cost implications of consuming another kWh, we should not downplay the importance of the pricing associated with peak demands. Taken to its extreme, marginal cost studies that minimize demand costs and reflect only flat energy costs would result in price signals that give no indication of the timing of their energy decisions. This would result in a price signal that is the same whether the customer increased his usage in summer or winter, afternoon hours or at 3 A.M. in the morning.

Q. DOES PACIFICORP PROVIDE ANY RECOGNITION OF HIGH LOAD AND LOW LOAD HOURS IN ITS COST STUDY ALLOCATION OF THE MARGINAL COST OF ENERGY?

A. No. The generation marginal energy cost is applied to all 8,760 hours of the year equally, thereby ignoring any time-of-day cost differentiation. This gives no recognition to those customers who may be using energy in a more efficient manner, or during times of lower system cost.

Q. IS PACIFICORP PROPOSING TO IMPLEMENT TIME-OF-DAY PRICING FOR LARGE GENERAL SERVICE CUSTOMERS?

A. Yes. Ironically, the Company proposes to differentiate Schedule 200 Supply Service energy charges into on-peak and off-peak prices. PPL/1200, Griffith/11. According to the Company, this differentiation is proposed to "reflect higher on-peak power prices." However, the Company has made no effort in its marginal cost study to reflect the fact that on-peak generation costs are higher despite its proposal for time-of-day pricing. In fact, just the opposite is reflected in the marginal cost study where over 70% of the generation costs are classified and allocated on the basis of a single marginal cost of energy across all hours of the year.

II. RECONCILIATION OF MARGINAL COSTS

Q. HOW DOES PACIFICORP RECONCILE TOTAL MARGINAL COSTS TO THE TARGET REVENUE REQUIREMENT?

A. PacifiCorp reconciles the marginal costs of generation and transmission to the target revenue requirement on a functional basis that ignores the underlying energy and demand classifications. In other words, PacifiCorp recognizes only a single generation function, not a generation energy function and a generation demand function. Likewise, a single transmission function is used.

Q. COULD THE FUNCTIONAL RECONCILIATION APPROACH BE IMPROVED IN THIS CASE IN ORDER TO PROVIDE A BETTER SIGNAL AS TO THE COST OF GENERATION AND TRANSMISSION?

A. Yes. I believe that the reconciliation process could be improved through the use of generation demand, generation energy, transmission demand and transmission energy functions. This would result in an allocation of revenues to ensure fair treatment of the underlying functional costs.

It is evident that in its last three filed cases, PacifiCorp's energy component of generation marginal costs are shifting a larger portion of generation costs to larger, higher load factor customers. No corresponding effort has been made by PacifiCorp, however, to improve the marginal study as to seasonality of prices, load patterns of usage, or to "reflect higher on-peak power prices." This marginal study treats all kWhs of energy alike, regardless of time of day, season, or costing impacts.

ICNU believes that the higher cost to serve customers using relatively more of their energy during on-peak, higher cost periods should be reflected in the marginal cost study. As one step in that process, we recommend the reconciliation process be refined to better align the marginal costs to their functional energy and demand components.

Q. HAVE YOU PREPARED A STUDY WHICH USES THIS REFINED RECONCILIATION METHOD?

A. Yes. Exhibit ICNU/303 shows the results of reconciling to generation and transmission energy and demand functions. ICNU recommends that base rates be established for customer classes using this reconciliation approach. For example, PacifiCorp reconciles the entire generation marginal cost of $552 million to the entire target generation revenue requirement of $510 million through the use of a single functional revenue requirement allocation factor. Our recommendation would refine this allocation by reconciling the generation energy marginal cost of $394 million to the target generation energy-related revenue requirement of $259 million, and the generation demand marginal cost of $157 million to the generation demand-related revenue requirement of $251 million.

Q. WHY WOULD THIS RECONCILIATION BE AN IMPROVEMENT OVER THE CURRENT PRACTICE?

A. When the Commission first started using marginal costs as one of the principal factors for spreading revenue requirement among customer classes in 1974, marginal costs were reconciled so that each customer class paid an equal percentage of marginal costs. In 1996, this process was refined by switching to equal percentages of marginal cost by function. In adopting this switch the Commission noted:

> This new approach will improve our historical efforts to allocate cost responsibility to customer classes in ways that lead to more efficient price signals for customers and efficient use of electrical service. It will also improve fairness in our rates by ensuring that the costs of one function (e.g., distribution) do not affect the allocation of the costs of another

> function (e.g., generation). Finally, adopting this stipulation will provide us valuable information when we consider whether and how electric service should be provided on an unbundled basis.

Re Investigation of Methods Estimating Marginal Costs of Servie for Electric Utilities, Docket No. UM 827, Order No. 98-374 (Sept. 11, 1998).

Likewise, adopting this refinement in the functional reconciliation will improve cost responsibility to customer classes and will better reflect the results of the Revised Protocol jurisdictional study. It will improve fairness in the rates by ensuring that classes with high load factors are not penalized, or conversely that classes with poor load factors will be allocated an appropriate level of generation demand costs.

Q. PLEASE EXPLAIN HOW YOUR PROPOSALS WOULD IMPACT THE UNBUNDLED REVENUE REQUIREMENT ALLOCATION BY RATE SCHEDULE.

A. The following table compares PacifiCorp's unbundled revenue requirement allocation (PPL/409, Taylor/1; PPL/1202, Griffith/1) to ICNU's unbundled revenue requirement allocations:

Increase in Revenues to Meet
Unbundled Revenue Requirement Allocation

	PacifiCorp	ICNU
Residential:		
Schedule 4	10.41%	11.22%
Commercial & Industrial:		
Schedule 23	25.36%	27.41%
Schedule 28	2.99%	3.00%
Schedule 30	9.55%	9.79%
Schedule 48	21.64%	18.51%
Schedule 41	18.27%	18.93%
Lighting	-2.78%	-9.29%
Total	12.48%	12.57%

III. RATE SPREAD AND RATE DESIGN

Q. HOW HAS PACIFICORP PROPOSED TO ALLOCATE AND RECOVER ANY REVENUE INCREASE RESULTING FROM THIS PROCEEDING?

A. PacifiCorp allocates the increase in base rates based on the results of its functionalized class cost of service study. Net rates are then developed to include the effect of riders for several adjustment schedules. For the proposed riders, presently effective Schedule 94, Deferred Accounting Adjustment, will have expired, and Proposed Schedule 95, Miscellaneous Deferred Accounts Credit, will be implemented. Furthermore, changes will be made to the Rate Mitigation Adjustment ("RMA") Schedule 299.

Q. DO YOU AGREE WITH THE COMPANY'S RATE SPREAD OBJECTIVES IN THIS CASE?

A. Yes. The Company proposes to implement a rate spread where none of the major rate schedules will see an overall net rate increase greater than approximately 1.5 times the overall average net. I agree with this overall objective, as well as the Company's proposal to set the RMA to zero for both residential and Schedule 47/48 customers. However, our recommendation would start from functionalized revenue requirements by class according to the method employed in ICNU/303.

Q. HAVE YOU DEVELOPED A SPECIFIC RECOMMENDATON FOR THE SPREAD OF ANY REVENUE INCREASE?

A. Yes. For comparison purposes, ICNU/304 presents my recommendation using the same dollar amount increase that PacifiCorp has requested. I present this strictly for comparison purposes, and it should not be interpreted as a recommendation that PacifiCorp is entitled to receive the amount of increase that it has requested.

Q. HOW DOES YOUR RECOMMENDED RATE SPREAD DIFFER FROM PACIFICORP'S?

A. Both PacifiCorp's and my recommendation show that the Residential class should receive increases greater than the system average. In addition, both PacifiCorp's and my recommendation show that lighting should receive increases roughly half of the system average. We both show that Schedule 23 and 41 should be capped at roughly 150% of the system average. Schedules 28 and 30 would receive increases of roughly 27% of the system average under my recommendation, in comparison to PacifiCorp's recommendation for increases of 18% of system average. For Schedule 48, my recommendation results in an increase of 78% of system average compared to PacifiCorp's proposal for 119% of system average. The following table compares the relative net rate increases under PacifiCorp's and ICNU's proposals:

Proposed Relative Net Rate Increases

	PacifiCorp	ICNU
Residential:		
Schedule 4	1.25	1.37
Commercial & Industrial:		
Schedule 23	1.48	1.48
Schedule 28	0.15	0.27
Schedule 30	0.19	0.28
Schedule 48	1.19	0.78
Schedule 41	1.48	1.48
Lighting	0.51	0.52
Total	1.00	1.00

Q. DO YOU AGREE WITH THE COMPANY'S ORIGINAL PROPOSED RATE DESIGN FOR SCHEDULE 48T?

A. No. PacifiCorp originally filed proposed rates that recovered only the substation costs in the On-Peak Demand Charge, and the non-FERC transmission in the Facilities Charges. Exhibit ICNU/305, which is an excerpt of PacifiCorp's response to ICNU data request ("DR") No. 6.2, shows PacifiCorp's revision of its proposals so that both non-FERC transmission and substation costs are recovered through the On-Peak Demand charge. We agree with this revision.

Q. DO YOU SUPPORT PACIFICORP'S PROPOSAL FOR TIME-OF-DAY PRICING FOR SCHEDULE 48?

A. No. The proposed time-of-day pricing for Schedule 200 service to large power customers should be rejected. As explained earlier, since the underlying marginal cost study has no recognition for differentiating energy costs by time of use, this pricing proposal is simply a rate design strategy to boost revenues for energy sold to large power users during on-peak times. Customers who shift usage to off-peak times, however, will see no benefit in subsequent revenue allocation since the Company's cost study makes no distinction between on-peak and off-peak energy usage.

Q. UPON WHAT BASIS DOES PACIFICORP MAKE ITS TIME-OF-DAY PRICING PROPOSAL?

A. None. PacifiCorp simply designed the on-peak and off-peak prices to recover, in part, the proposed revenue requirement for Schedule 48. In fact, as explained in the response to KWUA DR No. 1.20, which is provided as Exhibit ICNU/306, there are no documents for the proposed pricing differential:

> No documents were derived or prepared to support the selection of the proposed energy differential of 3 mills per kWh. Three mills was selected to provide some incentive for Consumers to switch their loads from on-peak to off-peak, while having a mild impact on those Consumers who

might not be able to change their consumption patterns and switch loads from on-peak to off-peak.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Qualifications of Kathryn E. Iverson

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Kathryn E. Iverson, 17244 W. Cordova Court, Surprise, Arizona 85387.

Q. PLEASE STATE YOUR OCCUPATION.

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. In 1980 I received a Bachelors of Science Degree in Agricultural Sciences from Colorado State University, and in 1983, I received a Masters of Science Degree in Economics from Colorado State University.

In March of 1984, I accepted a position as Rate Analyst with the consulting firm Browne, Bortz and Coddington in Denver, Colorado. My duties included evaluation of proposed utility projects, benefit-cost analysis of resource decisions, cost of service studies and rate design, and analyses of transmission and substation equipment purchases.

In February 1986, I accepted a position with Applied Economics Group, where I was responsible for utility economic analysis including cogeneration projects, computer modeling of power requirements for an industrial pumping facility, and revenue impacts associated with various proposed utility tariffs. In January of 1989, I was promoted to the position of Vice President. In this position, I assumed the additional responsibilities of project leader on projects, including the analysis of alternative cost recovery methods, pricing, rate design and DSM adjustment clauses, and representation of a group of industrial customers on the Conservation and Least Cost Planning Advisory Committee to Montana Power Company.

In March 1992, I accepted a position with ERG International Consultants, Inc., of Golden, Colorado as Senior Utility Economist. While at ERG, I was responsible for the cost-effectiveness analysis of demand-side programs for Western Area Power Administration customers. I also assisted in the development of a reference manual on the process of Integrated Resource Planning including integration of supply and demand resource, public participation, implementation of the resource plan and elements of writing a plan. I lectured and provided instructional materials on the key concept of life-cycle costing seminars held to provide resource planners and utility decision-makers with a background and basic understanding of the fundamental techniques of economic analysis. My work also included the evaluation of a marginal cost of service study, assessment of avoided cost rates, and computer modeling relating engineering simulation models to weather-normalized loads of schools in California.

In November of 1994, I accepted a position with Drazen-Brubaker & Associates, Inc. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since joining this firm, I have performed various analyses of integrated resource plans, examination of cost of service studies and rate design, fuel cost recovery proceedings, as well as estimates of transition costs and restructuring plans.

Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified before the regulatory commissions in Colorado, Georgia, Idaho, Michigan, Montana, Texas and Wyoming.

PACIFIC POWER & LIGHT COMPANY
Generation and Transmission Revenue Requirements
As Filed by PacifiCorp

Ln	Description	Generation		Transmission	
1	Total Revenue Requirement	$ 524,544,979		$ 68,036,871	
	Energy-Related Expenses				
2	SE Expenses	$ 143,146,050		$ 825,681	
3	SSECT Expenses	$ 25,936,056			
4	SSECH Expenses	$ 11,694,994			
5		$ 180,777,100		$ 825,681	
6	Remaining Amount	$ 343,767,879		$ 67,211,190	
7	x 25%	$ 85,941,970		$ 16,802,798	
8	Energy-Related	$ 266,719,070	51%	$ 17,628,479	26%
9	Demand-Related	$ 257,825,909	49%	$ 50,408,393	74%
10	Total	$ 524,544,979	100%	$ 68,036,871	100%

Source:
(1): Exhibit PPL/409, Target Functional Revenue Requirement
(2) - (4): Exhibit PPL/801, Page 2.10, lines 545, 557, 560; Page 2.11, line 644
(6): (1) - (5)
(7): (6) x 25%
(8): (5) + (7)
(9): (1) - (8)

PACIFIC POWER & LIGHT COMPANY

December 31, 2006 Unbundled Generation and Transmission Revenue Requirement Allocation by Rate Schedule

			Residential	General Service Sch 23		General Service Sch 28		General Service Sch 30		Large Power Service Schedule 48T			Sch 41	St Lighting
Line	Description	Total	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(sec)
1	**Total Operating Revenues**	$792,332	$389,311	74,320	48	116,436	1,170	66,066	4,401	38,668	68,765	19,309	10,351	3,487
2	**MWH**	13,265,983	5,079,177	1,110,753	728	2,087,230	22,353	1,341,152	91,525	901,394	1,872,828	614,130	119,204	25,509
3														
4	**Functionalized 20 Year Full Marginal Costs - Class $**													
5	Generation Demand	$157,353	$64,343	$15,176	$10	$24,812	$249	$16,148	$1,068	$10,197	$18,638	$5,212	$1,500	$0
6	Generation Energy	$394,480	$152,012	$33,243	$21	$62,467	$650	$40,139	$2,663	$26,977	$54,500	$17,476	$3,568	$763
7	Generation	$551,833	$216,355	$48,419	$31	$87,279	$899	$56,287	$3,731	$37,174	$73,138	$22,688	$5,068	$763
8	Transmission Demand	$29,165	$11,926	$2,813	$2	$4,599	$46	$2,993	$198	$1,890	$3,454	$966	$278	$0
9	Transmission Energy	$25,381	$9,780	$2,139	$1	$4,019	$42	$2,583	$171	$1,736	$3,507	$1,124	$230	$49
10	Transmission	$54,546	$21,706	$4,952	$3	$8,618	$88	$5,576	$369	$3,626	$6,961	$2,090	$508	$49
11	Distribution	$285,855	$180,358	$40,437	$15	$27,470	$218	$13,395	$840	$6,759	$6,276	$0	$7,020	$3,067
12	Customer - Billing	$12,410	$10,046	$1,411	$1	$498	$3	$49	$3	$110	$72	$1	$197	$19
13	Customer - Metering	$15,344	$11,439	$2,203	$33	$877	$62	$203	$64	$38	$105	$23	$294	$1
14	Customer - Other	$8,679	$7,203	$942	$0	$283	$2	$53	$3	$54	$35	$0	$96	$9
15	Total	$928,667	$447,107	$98,365	$84	$125,025	$1,272	$75,562	$5,011	$47,761	$86,586	$24,803	$13,182	$3,909
16														
17	**Functional Revenue Requirement Allocation Factors**													
18	**Functionalized 20 Year Full Marginal Costs - Class % of Total**													
19	Generation Demand	100.00%	40.89%	9.64%	0.01%	15.77%	0.16%	10.26%	0.68%	6.48%	11.84%	3.31%	0.95%	0.00%
20	Generation Energy	100.00%	38.53%	8.43%	0.01%	15.84%	0.16%	10.18%	0.68%	6.84%	13.82%	4.43%	0.90%	0.19%
21	Transmission Demand	100.00%	40.89%	9.65%	0.01%	15.77%	0.16%	10.26%	0.68%	6.48%	11.84%	3.31%	0.95%	0.00%
22	Transmission Energy	100.00%	38.53%	8.43%	0.01%	15.84%	0.16%	10.18%	0.68%	6.84%	13.82%	4.43%	0.90%	0.19%
23	Distribution	100.00%	63.09%	14.15%	0.01%	9.61%	0.08%	4.69%	0.29%	2.36%	2.20%	0.00%	2.46%	1.07%
24	Ancillary Service	100.00%	39.21%	8.77%	0.01%	15.82%	0.16%	10.20%	0.68%	6.74%	13.25%	4.11%	0.92%	0.14%
25	Customer - Billing	100.00%	80.95%	11.37%	0.00%	4.02%	0.02%	0.39%	0.02%	0.89%	0.58%	0.01%	1.59%	0.16%
26	Customer - Metering	100.00%	74.55%	14.36%	0.22%	5.72%	0.40%	1.32%	0.42%	0.25%	0.69%	0.15%	1.91%	0.01%
27	Customer - Other	100.00%	82.99%	10.85%	0.00%	3.26%	0.02%	0.61%	0.04%	0.62%	0.40%	0.00%	1.10%	0.11%
28	Embedded DSM - (mWh)	100.00%	38.29%	8.37%	0.01%	15.73%	0.17%	10.11%	0.69%	6.79%	14.12%	4.63%	0.90%	0.19%
29	Regulatory & Franchise	100.00%	49.13%	9.38%	0.01%	14.70%	0.15%	8.34%	0.56%	4.88%	8.68%	2.44%	1.31%	0.44%
30	Taxes (Revenue)													
31														
32	**Functionalized Class Revenue Requirement - (Target)**													
33	Generation Demand	$250,671	102,502	24,176	16	39,527	397	25,725	1,701	16,244	29,691	8,303	2,390	0
34	Generation Energy	$259,318	99,927	21,853	14	41,064	428	26,386	1,751	17,734	35,826	11,488	2,345	502
35	Generation	$509,989	202,429	46,029	30	80,591	824	52,110	3,452	33,978	65,518	19,791	4,735	502
36	Transmission Demand	$49,010	20,041	4,727	3	7,728	77	5,030	333	3,176	5,804	1,623	467	0
37	Transmission Energy	$17,139	6,605	1,444	1	2,714	28	1,744	116	1,172	2,368	759	155	33
38	Transmission	$66,149	26,645	6,171	4	10,442	106	6,773	448	4,348	8,172	2,383	622	33
39	Distribution	$231,475	146,047	32,745	12	22,244	177	10,847	680	5,473	5,082	0	5,684	2,484
40	Ancillary Services	$6,757	2,649	593	0	1,069	11	689	46	455	896	278	62	9
41	Customer - Billing	$22,859	18,504	2,599	1	918	5	90	5	203	132	1	364	36
42	Customer - Metering	$24,674	18,394	3,543	53	1,411	100	326	103	62	169	37	472	2
43	Customer - Other	$10,570	8,773	1,147	0	344	2	64	4	65	42	0	116	11
44	Embedded DSM - (mWh)	$0	0	0	0	0	0	0	0	0	0	0	0	0
45	Regulatory & Franchise T	$19,451	9,557	1,824	1	2,858	29	1,622	108	949	1,688	474	254	86
46	Total	$891,923	$432,999	$94,652	$103	$119,877	$1,253	$72,522	$4,847	$45,534	$81,699	$22,965	$12,310	$3,163
47														
48	Ratio of Oper Rev to Rev Req - (Target)	88.83%	89.91%	78.52%	47.16%	97.13%	93.37%	91.10%	90.80%	84.92%	84.17%	84.08%	84.09%	110.25%
49	(Line 1 / Line 46)													
50														
51	Increase or (Decrease)	99,591	43,688	20,332	54	3,441	83	6,456	446	6,866	12,935	3,656	1,959	(324)
52	(Line 46 - Line 1)													
53														
54	Percent Increase (Decrease)	12.57%	11.22%	27.36%	112.03%	2.96%	7.10%	9.77%	10.13%	17.76%	18.81%	18.93%	18.93%	-9.29%

PACIFIC POWER & LIGHT COMPANY
ESTIMATED EFFECT OF PROPOSED PRICE CHANGE
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
DISTRIBUTED BY RATE SCHEDULES IN OREGON
FORECAST 12 MONTHS ENDED DECEMBER 31, 2006

						Present Revenues ($000)			Proposed Revenues ($000)			Change			
												Base Rates		Net Rates	
Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Base Rates	Adders[1]	Net Rates	Base Rates	Adders[1,2]	Net Rates	($000)	%	($000)	%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								(6) + (7)			(9) + (10)	(9) - (6)	(12)/(6)	(11) - (8)	(14)/(8)
	Residential														
1	Residential	4	4	460,491	5,079,177	$389,311	($559)	$388,752	$432,984	($8,329)	$424,655	$43,673	11.2%	$35,903	9.2%
2	Total Residential			460,491	5,079,177	$389,311	($559)	$388,752	$432,984	($8,329)	$424,655	$43,673	11.2%	$35,903	9.2%
	Commercial & Industrial														
3	Gen. Svc. < 31 kW	23/36	23	68,716	1,111,483	$74,368	$3,935	$78,303	$94,750	($8,670)	$86,080	$20,382	27.4%	$7,777	9.9%
4	Gen. Svc. 31 - 200 kW	28/36	28	9,809	2,110,361	$117,664	$7,912	$125,576	$121,190	$6,607	$127,797	$3,526	3.0%	$2,221	1.8%
5	Gen. Svc. 201 - 999 kW	30/36	30	1,017	1,436,166	$70,762	$5,802	$76,564	$77,629	$358	$77,987	$6,867	9.7%	$1,423	1.9%
6	Large General Service >= 1,000 kW	48	48	231	3,388,352	$126,742	$11,873	$138,615	$150,278	($4,437)	$145,841	$23,536	18.6%	$7,226	5.2%
7	Partial Req. Svc. >= 1,000 kW	47	47	7	230,294	$10,889	$488	$11,377	$12,140	($319)	$11,821	$1,251	11.5%	$444	3.9%
8	Agricultural Pumping Service	41	41	6,229	119,204	$10,351	($2,029)	$8,322	$12,311	($3,162)	$9,149	$1,960	18.9%	$827	9.9%
9	Agricultural Pumping - Other	--[3]	41	2,110	90,609	$7,709	($1,542)	$6,167	$9,160	($2,404)	$6,756	$1,451	18.8%	$589	9.6%
10	Total Commercial & Industrial			88,119	8,486,469	$418,485	$26,439	$444,924	$477,458	($12,027)	$465,431	$58,973	14.1%	$20,507	4.6%
	Lighting														
11	Outdoor Area Lighting Service	15	15	7,933	12,626	$1,584	$47	$1,631	$1,436	$253	$1,689	($148)	-9.3%	$58	3.6%
12	Street Lighting Service	50	50	316	11,391	$1,251	$41	$1,292	$1,134	$204	$1,338	($117)	-9.4%	$46	3.6%
13	Street Lighting Service HPS	51	51	667	16,349	$2,883	$70	$2,953	$2,614	$444	$3,058	($269)	-9.3%	$105	3.6%
14	Street Lighting Service	52	52	111	1,998	$232	$7	$239	$211	$36	$247	($21)	-9.1%	$8	3.4%
15	Street Lighting Service	53	53	229	8,400	$538	$29	$567	$488	$99	$587	($50)	-9.3%	$20	3.5%
16	Recreational Field Lighting	54	54	91	760	$65	$2	$67	$59	$10	$69	($6)	-9.2%	$2	3.0%
17	Total Public Street Lighting			9,347	51,524	$6,553	$196	$6,749	$5,942	$1,046	$6,988	($611)	-9.3%	$239	3.5%
18	Total Sales to Ultimate Consumers			557,957	13,617,170	$814,349	$26,076	$840,425	$916,384	($19,310)	$897,074	$102,035	12.5%	$56,649	6.7%
19	Employee Discount				20,911	($397)	$1	($396)	($442)	$9	($433)	($45)		($37)	
20	Total Sales with Employee Discount			557,957	13,617,170	$813,952	$26,077	$840,029	$915,942	($19,301)	$896,641	$101,990	12.5%	$56,612	6.7%
21	AGA Revenue					$1,404		$1,404	$1,404		$1,404	$0		$0	
22	Total Sales with Employee Discount and AGA			557,957	13,617,170	$815,356	$26,077	$841,433	$917,346	($19,301)	$898,045	$101,990	12.5%	$56,612	6.7%

[1] Excludes effects of the BPA Energy Discount (Schedule 98), Low Income Bill Payment Assistance Charge (Schedule 91) and Public Purpose Charge (Schedule 290).
[2] Removal of Sch 94 and includes new Sch 95 Miscellaneous Defferred Accounts Credit $1.8 million.
[3] UKRB and USBR on Schedule 41 rates.

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Forecast 12 Months Ended December 31, 2006

Schedule	Forecast 1/06 - 12/06 Units		Present Price	Present Dollars	Proposed Price	Proposed Dollars
Schedule No. 48/748 - Composite						
Large General Service (Secondary)						
Transmission & Ancillary Services Charge						
per kW of billing demand	2,309,263	kW	$1.59	$3,671,728		
per kW of on-peak demand	2,299,480	kW			$1.48	$3,403,230
Distribution Charge						
Basic Charge						
Load Size ≤4,000 kW, per month	1,638	bill	$240.00	$393,120	$290.00	$475,020
Load Size > 4,000 kW, per month	43	bill	$440.00	$18,920	$540.00	$23,220
Load Size/Facility Charge						
Load Size ≤4,000 kW, per kW	2,444,513	kW	$0.50	$1,222,257	$1.50	$3,666,770
Load Size > 4,000 kW, per kW	302,852	kW	$0.45	$136,283	$1.35	$408,850
Demand Charge, per kW of billing demand	2,309,263	kW	$1.95	$4,503,063		
Demand Charge, per kW of on-peak demand	2,299,480	kW			$1.40	$3,219,272
Reactive Power Charge, per kvar	658,364	kvar	65.00 ¢	$427,937	65.00 ¢	$427,937
Energy Charge (Sch 200)						
per kWh	901,394,001	kWh	3.139 ¢	$28,294,758		
per on-peak kWh	552,026,599	kWh			3.921 ¢	$21,644,963
per off-peak kWh	349,367,402	kWh			3.621 ¢	$12,650,594
Total	901,394,001			$38,668,066		$45,919,856
					Change	$7,251,790
Schedule No. 48/748 - Composite						
Large General Service (Primary)						
Transmission & Ancillary Services Charge						
per kW of billing demand	3,979,223	kW	$1.64	$6,525,926		
per kW of on-peak demand	3,962,364	kW			$1.58	$6,260,535
Distribution Charge						
Basic Charge						
Load Size ≤4,000 kW, per month	679	bill	$220.00	$149,380	$260.00	$176,540
Load Size > 4,000 kW, per month	401	bill	$400.00	$160,400	$480.00	$192,480
Load Size/Facility Charge						
Load Size ≤4,000 kW, per kW	1,304,284	kW	$0.45	$586,928	$0.70	$912,999
Load Size > 4,000 kW, per kW	3,493,859	kW	$0.40	$1,397,544	$0.60	$2,096,315
Demand Charge, per kW of billing demand	3,979,223	kW	$1.42	$5,650,497		
Demand Charge, per kW of on-peak demand	3,962,364	kW			$1.55	$6,141,664
Reactive Power Charge, per kvar	937,809	kvar	60.00 ¢	$562,685	60.00 ¢	$562,685
Energy Charge (Sch 200)						
per kWh	1,872,827,573	kWh	2.869 ¢	$53,731,423		
per on-peak kWh	1,146,946,436	kWh			3.727 ¢	$42,746,694
per off-peak kWh	725,881,137	kWh			3.427 ¢	$24,875,947
Total	1,872,827,573			$68,764,783		$83,965,859
					Change	$15,201,076
Schedule No. 48/748 - Industrial						
Large General Service (Transmission)						
Transmission & Ancillary Services Charge						
per kW of billing demand	955,177	kW	$1.87	$1,786,181		
per kW of on-peak demand	940,641	kW			$1.90	$1,787,218
Distribution Charge						
Basic Charge						
Load Size ≤4,000 kW, per month	0	bill	$200.00	$0	$300.00	$0
Load Size > 4,000 kW, per month	12	bill	$370.00	$4,440	$550.00	$6,600
Load Size/Facility Charge						
Load Size ≤4,000 kW, per kW	0	kW	$0.40	$0	$0.40	$0
Load Size > 4,000 kW, per kW	1,041,926	kW	$0.40	$416,770	$0.40	$416,770

PACIFIC POWER & LIGHT COMPANY
State of Oregon
Billing Determinants
Forecast 12 Months Ended December 31, 2006

Schedule	Forecast 1/06 - 12/06 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Demand Charge, per kW of billing demand	955,177	kW	$0.55		$525,347			
Demand Charge, per kW of on-peak demand	940,641	kW				$1.09		$1,025,299
Reactive Power Charge, per kvar	157,612	kvar	55.00	¢	$86,687	55.00	¢	$86,687
Energy Charge (Sch 200)								
per kWh	614,130,342	kWh	2.685	¢	$16,489,400			
per on-peak kWh	344,060,421	kWh				3.543	¢	$12,190,061
per off-peak kWh	270,069,921	kWh				3.243	¢	$8,758,368
Total	614,130,342				$19,308,825			$24,271,003
						Change		$4,962,178

KWUA Data Request 1.20

With regard to PPL/1200, Griffith/11, lines 9-13, provide a copy of all documents used to derive and support the proposed on-peak and off-peak energy price differential.

Response to KWUA Data Request 1.20

As reflected in Exhibit PPL/1203, the on-peak and off-peak energy prices were designed to recover, in part, the proposed revenue requirement for Schedule 48. No documents were derived or prepared to support the selection of the proposed energy price differential of 3 mills per kWh. Three mills was selected to provide some incentive for Consumers to switch their loads from on-peak to off-peak, while having a mild impact on those Consumers who might not be able to change their consumption patterns and switch loads from on-peak to off-peak.

Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● mail@dvclaw.com
Suite 400
333 S.W. Taylor
Portland, OR 97204

May 9, 2005

Via Electronic and US Mail

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

Re: In the Matter of PACIFIC POWER & LIGHT Request for a General Rate Increase in the Company's Oregon Annual Revenues
Docket No. UE 170

Dear Filing Center:

Enclosed please find the following items for filing in the above-referenced proceeding on behalf of the Industrial Customers of Northwest Utilities:

- five (5) copies of the Confidential Direct Testimony of Randall Falkenberg, with confidential information in separate envelopes (these copies are unbound to allow for easy integration of the separately provided confidential pages);

- two (2) copies of the Redacted Direct Testimony of Randall Falkenberg;

- five (5) copies of the Direct Testimony of James Selecky; and

- five (5) copies of the Direct Testimony of Kathryn Iverson.

Thank you for your assistance.

Sincerely,

/s/ Christian Griffen
Christian W. Griffen

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Testimonies of Randall Falkenberg, James Selecky and Kathryn Iverson on behalf of the Industrial Customers of Northwest Utilities upon the parties on the service list by causing the same to be mailed, postage-prepaid, through the U.S. Mail. Only those parties who executed the Protective Order are receiving confidential versions of Mr. Falkenberg's testimony.

Dated at Portland, Oregon, this 9th day of May, 2005.

/s/ Christian Griffen
Christian W. Griffen

RATES & REGULATORY AFFAIRS PORTLAND GENERAL ELECTRIC RATES & REGULATORY AFFAIRS 121 SW SALMON STREET, 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com	JIM ABRAHAMSON **-- CONFIDENTIAL** COMMUNITY ACTION DIRECTORS OF OREGON 4035 12TH ST CUTOFF SE STE 110 SALEM OR 97302 jim@cado-oregon.org
EDWARD BARTELL KLAMATH OFF-PROJECT WATER USERS INC 30474 SPRAGUE RIVER ROAD SPRAGUE RIVER OR 97639	KURT J BOEHM **-- CONFIDENTIAL** BOEHM KURTZ & LOWRY 36 E SEVENTH ST - STE 1510 CINCINNATI OH 45202 kboehm@bkllawfirm.com
LISA BROWN WATERWATCH OF OREGON 213 SW ASH ST STE 208 PORTLAND OR 97204 lisa@waterwatch.org	LOWREY R BROWN **-- CONFIDENTIAL** CITIZENS' UTILITY BOARD OF OREGON 610 SW BROADWAY, SUITE 308 PORTLAND OR 97205 lowrey@oregoncub.org
PHIL CARVER OREGON DEPARTMENT OF ENERGY 625 MARION ST NE STE 1 SALEM OR 97301-3742 philip.h.carver@state.or.us	JOAN COTE **-- CONFIDENTIAL** OREGON ENERGY COORDINATORS ASSOCIATION 2585 STATE ST NE SALEM OR 97301 cotej@mwvcaa.org
JASON EISDORFER **-- CONFIDENTIAL** CITIZENS' UTILITY BOARD OF OREGON 610 SW BROADWAY STE 308 PORTLAND OR 97205 jason@oregoncub.org	JOHN DEVOE WATERWATCH OF OREGON 213 SW ASH STREET, SUITE 208 PORTLAND OR 97204 john@waterwatch.org

EDWARD A FINKLEA **-- CONFIDENTIAL** CABLE HUSTON BENEDICT HAAGENSEN & LLOYD LLP 1001 SW 5TH, SUITE 2000 PORTLAND OR 97204 efinklea@chbh.com	DAVID HATTON **-- CONFIDENTIAL** DEPARTMENT OF JUSTICE REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 david.hatton@state.or.us
JUDY JOHNSON **-- CONFIDENTIAL** PUBLIC UTILITY COMMISSION PO BOX 2148 SALEM OR 97308-2148 judy.johnson@state.or.us	JASON W JONES DEPARTMENT OF JUSTICE REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 jason.w.jones@state.or.us
DAN KEPPEN KLAMATH WATER USERS ASSOCIATION 2455 PATTERSON STREET, SUITE 3 KLAMATH FALLS OR 97603	MICHAEL L KURTZ **-- CONFIDENTIAL** BOEHM, KURTZ & LOWRY 36 E 7TH ST STE 1510 CINCINNATI OH 45202-4454 mkurtz@bkllawfirm.com
KATHERINE A MCDOWELL STOEL RIVES LLP 900 SW FIFTH AVE STE 1600 PORTLAND OR 97204-1268 kamcdowell@stoel.com	MATTHEW W PERKINS DAVISON VAN CLEVE PC 333 SW TAYLOR, STE 400 PORTLAND OR 97204 mwp@dvclaw.com
JANET L PREWITT DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM OR 97301-4096 janet.prewitt@doj.state.or.us	GLEN H SPAIN PACIFIC COAST FEDERATION OF FISHERMEN'S ASSOC PO BOX 11170 EUGENE OR 97440-3370 fish1ifr@aol.com
DOUGLAS C TINGEY PORTLAND GENERAL ELECTRIC 121 SW SALMON 1WTC13 PORTLAND OR 97204 doug.tingey@pgn.com	ROBERT VALDEZ PO BOX 2148 SALEM OR 97308-2148 bob.valdez@state.or.us
PAUL M WRIGLEY PACIFIC POWER & LIGHT 825 NE MULTNOMAH STE 800 PORTLAND OR 97232 paul.wrigley@pacificorp.com	