BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

UE-170

General Rate Case

Sur-Surrebuttal Testimony and Exhibits

July 2005

1701 Larson Testimony

Case UE-170
PPL Exhibit 1701
Witness: D. Douglas Larson

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-Surrebuttal Testimony of D. Douglas Larson

Policy

July 2005

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is D. Douglas Larson.

Q. Are you the same D. Douglas Larson who offered testimony in this proceeding?

A. Yes. I filed rebuttal testimony in this proceeding and adopted the direct testimony of Donald Furman.

Purpose and Summary of Testimony

Q. What is the purpose of your sur-surrebuttal testimony?

A. My testimony provides an overall perspective on the Company's proposed revenue requirement increase in this case. I discuss the key remaining issues in the case and describe the various stipulations and Company concessions that have narrowed the issues in dispute. I highlight the importance of the outcome of this case to PacifiCorp and its customers, in terms of ensuring that PacifiCorp's credit ratings and financial status remain strong when the Company faces $1 billion annually in new capital expenditures. I explain that the Commission can grant PacifiCorp's revenue requirement request in the face of rising costs and expenditures with a moderate, single-digit rate increase. By rejecting extremes and embracing the reasonable, realistic positions of the Company on cost of capital, FAS pension expense and taxes, the Commission can deliver a win/win outcome in this case: financial stability for PacifiCorp and the continuation of low rates for customers.

Case Overview

Q. Please comment on the current status of this case.

A. Thanks to constructive engagement by Staff and intervenors, the parties have resolved a number of major issues in the case, including net power costs, O&M, non-labor A&G, incentives, benefits and standby rates for partial requirements customers. In addition, Staff and the Company have settled RVM power costs, with the Staff's agreement to support application of the Revised Protocol to the Company's new QF contracts and the waiver of the New Resource Rule for the West Valley Lease, the Gadsby CTs and Currant Creek. These agreements are contained in four Partial Stipulations, two described in my rebuttal testimony and two described below.

Another major issue in this case, the status of the Klamath irrigators' special contracts, was effectively bifurcated from the case by the agreement of the parties, memorialized in the Prehearing Conference Memorandum issued by Chief Administrative Law Judge Michael Grant on June 30th 2005, to waive the UE 170 suspension period for this issue and rely on Schedule 33 as the interim rate for these customers pending a final Commission decision before April 2006.

As a result, there are only three major revenue requirement issues that remain in dispute: cost of capital, pensions and taxes. Additionally, the major policy issue of PacifiCorp's RVM remains unsettled with respect to ICNU and CUB.

Q. Has PacifiCorp updated certain costs in its filing?

A. Yes. PacifiCorp has updated its capital costs by decreasing its costs of long-term debt and preferred equity. It has also updated its pension costs by increasing its FAS 87 expense, decreasing its FAS 106 expense and accepting Staff's pension administration adjustment.

Q. Has PacifiCorp updated its revenue requirement to reflect the current status of its filing?

A. Yes. Taking into account the effect of the three Partial Stipulations bearing on revenue requirement, the Klamath irrigators' interim rate and updated pension and capital costs, PacifiCorp's new proposed revenue requirement is $75.9 million. This constitutes a 9.3 percent increase, or an overall net increase of 3.5 percent, considering the end of the UM 995 deferral sometime this summer.

Cost of Capital

Q. Please explain why cost of capital issues are so critical to PacifiCorp in this case.

A. As discussed in my rebuttal, in order to continue to provide reliable service at reasonable cost, PacifiCorp anticipates the need to commit substantial amounts of new capital over the next several years. In addition to the many new capital investments reflected in this case, over the last few months PacifiCorp contracted for a major new 2005 wind resource, the 64.5 Wolverine Creek project, and has filed a new generation RFP with the Commission. PacifiCorp's ability to continue to make such infrastructure investments is contingent upon its regulators' support in setting reasonable rates of return. For example, in Fitch's most recent credit opinion on PacifiCorp, it cited low returns in the past as evidence that regulation remained PacifiCorp's primary risk in maintaining its credit quality.

Q. Is it fair to characterize the 9.5 percent ROE recommendation of Staff, ICNU and CUB as unreasonably low?

A. Yes. Viewed in the context of the Company's recent rate cases, this recommendation is 100 basis points lower than the 10.5 percent ROE stipulated to in PacifiCorp's last rate case less than two years ago, UE 147, and 125 basis points lower than the 10.75 percent ROE last set by the Commission in UE 116. It is also 100 basis points lower than the 10.5 ROE approved by the Utah Commission in January 2005.

As Mr. Hadaway notes, looking at Value Line ROE projections for companies in PacifiCorp's comparable group, the recommendation is 125 to130 basis points lower than the current 10.75-10.80 percent projection. It is also almost 125 basis points lower than the average allowed ROE for electric utilities in 2004, 141 basis points lower than the 10.91 ROE allowed in the last quarter of 2004, and 94 basis points lower than the 10.44 percent ROE allowed during the first quarter of 2005.

Q. Why does PacifiCorp believe that it is important for the Commission to "reality check" the ROE recommendations of Staff, ICNU and CUB by considering the comparisons just provided?

A. PacifiCorp is not unique in its need to raise capital to fund significant new utility infrastructure investments. Many utilities are in the midst of similar build cycles, competing for the same investment dollars as PacifiCorp. An extreme ROE outcome in this case places PacifiCorp at a competitive disadvantage vis-à-vis other utilities as it seeks access to the capital markets to meet its future capital obligations.

Q. Do Staff and the intervenors compound the problems associated with their very low recommended ROE by discounting the actual equity in PacifiCorp's capital structure?

A. Yes. Staff and intervenors recommend a capital structure that ignores the fact of ScottishPower's FY 2006 $500 million equity contribution to PacifiCorp, notwithstanding the fact that it has now clearly become a known and measurable event for the 2006 test year in this case. The Commission approved PacifiCorp's issuance of new equity shares in May 2005, ScottishPower made its first $125 million equity infusion in June 2005, and it is now required by the ScottishPower/MidAmerican Energy agreement to contribute a total of $500 million in new equity to PacifiCorp in FY 2006. It also ignores the fact that this new equity is required to maintain PacifiCorp's current credit ratings, because of PacifiCorp's capital investment needs, credit agencies' demands for increased equity ratios and their imputation of debt related to long-term PPAs.

Q. What are the implications of the combined ROE and capital structure recommendations of Staff, ICNU and CUB?

A. Mr. Williams' testimony reveals that even if PacifiCorp were able to earn the ROE recommended by Staff and intervenors, its resulting ratings metrics would be substantially below the ranges specified by the rating agencies for maintenance of PacifiCorp's current "A- level" bond ratings. The adverse impacts of these recommendations on the Company's bond ratings metrics are demonstrated in

Exhibit PPL/304/Williams/19, and are confirmed in the surrebuttal testimony of Mr. Gorman.

If adopted, the Staff and intervenor cost of capital recommendations would place the Company's credit ratings at risk of significant downgrade at a time that maintenance of an "A-level" rating is critical to the Company's ability to access the capital markets, the cost of current and future borrowings, and the ability to transact in the long-term markets for power purchases and sales. S&P recently placed PacifiCorp on CreditWatch with negative implications, so the risk of a downgrade is real if the Commission approves a cost of capital in this case that is unreasonably low.

Q. Please provide PacifiCorp's updated debt and preferred equity costs.

A. As discussed in the sur-surrebuttal testimony of Mr. Williams, the Company has updated its long-term debt and preferred equity rates to reflect recent decreases in interest rates. This update lowers the Company's long-term debt rate from 6.35 percent to 6.288 percent and the cost of preferred equity from 6.63 percent to 6.59 percent.

FAS Pension Costs

Q. Please explain the updates PacifiCorp made to its FAS pension costs in its sur-surebuttal testimony.

A. The Company made three changes to the level of pension expense included in this case: (1) the Company has increased its general pension expense in this case to $49.9 million, equal to the actual FAS 87 costs the Company will pay in 2005; (2) the Company lowered its FAS 106 expense by $2.8 million to reflect actual costs for calendar year 2005, which incorporates savings from a new Medicare law; and (3) the Company has conceded Mr. Dougherty's proposed pension administration expense adjustment and reduced the level of this expense from $1.3 million to $1.0 million, on a total company basis.

Q. Please explain why the Company made these updates.

A. As discussed in the testimony of Mr. Rosborough, all parties agree that the Company should be able to recover its actuarially determined FAS pension costs in rates, consistent with past Commission precedent. The only issue in dispute is whether the Company's projected 2006 FAS pension expense is accurate. To address this concern, the Company updated its filing to rely on the most recent actual year of FAS pension expense, 2005. In the case of FAS 87, this produces a higher number than originally filed; in the case of FAS 106, this produces a lower number than originally filed.

Q. What else has the Company done to address the concerns of Staff and ICNU about the accuracy of PacifiCorp's FAS pension expense for 2006?

A. PacifiCorp has provided testimony from its actuary, Mr. Kopec of Hewitt Associates, stating that PacifiCorp's FAS pension expense for 2006 will be the same or higher as PacifiCorp's 2005 FAS pension expense.

Q. Has the Company taken an additional step in this filing to address concerns about the amount of PacifiCorp's FAS pension expense for 2006?

A. Yes. Mr. Rosborough proposes a balancing account to address any variation between actual FAS pension expense and the level of expense set in this rate proceeding. The Company proposed similar treatment for its pension expense in

UE 147, consistent with the balancing account approved for NW Natural in Order 03-507, but this concept was not included in the parties' Stipulation in that case.

Q. Has the Company's actual FAS pension expense in the last two years been significantly more than that reflected in rates?

A. Yes. In 2004-05, the Company's actual FAS expense was almost $50 million greater than the amount now reflected in rates. To address and ameliorate PacifiCorp's significant under recovery of its FAS pension costs, the Commission should reset PacifiCorp's pension expense using its actual 2005 FAS pension expense.

Consolidated Tax Adjustments

Q. Staff introduced a tax adjustment for the first time in the joint surrebuttal testimony of Mr. Bryan Conway and Ms. Judy Johnson. Is this adjustment consistent with sound regulatory policy?

A. No. While Staff reiterates its support for the stand-alone method for calculating utility tax expenses, it has submitted an adjustment inconsistent with that methodology. As demonstrated in the testimony of Messrs. Williams and Martin, the adjustment proceeds from the premise that the ring fencing of PacifiCorp's operations has not been effective. The irony of this and other consolidated tax adjustments in the case is that the Commission's ring fencing conditions imposed on PacifiCorp in the ScottishPower merger have been effective, but may not remain so if the Commission permits the ring fence to be penetrated by such an adjustment.

Q. Are there other problems with Staff's consolidated tax adjustment?

Yes. As Mr. Williams notes, Staff acknowledges the speculative nature of their adjustment, admitting that the adjustment is not "precise" and that "perhaps" ring fencing has worked to insulate PacifiCorp from its parent. Additionally, the adjustment purports to calculate the impact on PacifiCorp if its parent's debt were included by credit agencies in the calculation of bond rating ratios for PacifiCorp. As Mr. Williams testifies, the credit agencies have never made an adjustment that included PHI's debt in PacifiCorp's rating metrics. To the extent that the credit agencies have considered PacifiCorp's affiliation with ScottishPower, it is to note the positive impact of the consolidated financial profile on PacifiCorp, not the opposite. Finally, Staff's adjustment contains factual errors, including reliance on incorrect credit ratings for ScottishPower and outdated S&P benchmarks.

Q. Are the consolidated tax adjustments of ICNU and CUB any more compelling?

A. No. ICNU and CUB, like Staff, propose to allocate to customers the tax benefits of another entity's expense but fail to demonstrate that such an allocation is appropriate. As noted by Mr. Martin, none of the three proposed tax adjustments comply with the opinion of the Oregon Department of Justice that the Commission has authority to make a consolidated tax adjustment only if it can demonstrate that utility customers "bore the burden of paying the deductible expenses that generated the savings." (Legality of Setting Utility Rates Based Upon the Tax Liability of Its Parent, Jason W. Jones, Dep't of Justice Memorandum, Feb. 18, 2005.)

ICNU does not even argue that this "benefits and burdens" legal standard is satisfied. Rather, ICNU witness Mr. James Selecky disregards the standard and argues instead for a change in the law.

While CUB pays lip service to the "benefits and burdens" legal standard, CUB has failed to provide any evidence that would satisfy it. Instead, CUB, like Staff, argues that the Commission should depart from the stand-alone approach to utility taxes because the ring fence has already been penetrated. In large part, CUB bases this assertion on its observation that the financial strength of PacifiCorp's corporate family impacts PacifiCorp's credit rating. However, as Mr. Williams demonstrates, and as Staff recognizes, the impact on PacifiCorp's credit rating has been positive. Rather than identifying a burden on customers sufficient to justify a consolidated tax adjustment, CUB and Staff have identified a benefit to customers. Finally, as Mr. Martin explains, CUB's other arguments are premised on numerous factual errors.

Other Issues

Q. Please address the parties' positions on PacifiCorp's RVM proposal.

A. Acknowledging PacifiCorp's proposal as the natural outgrowth of the Commission's order in UM 1081 regarding PacifiCorp's transition adjustment, Staff supports PacifiCorp's RVM proposal. CUB and ICNU, however, oppose the RVM for a variety of reasons. Ms. Omohundro responds to these concerns, explaining why the RVM sets the transition adjustment fairly and regularly updates power costs in a manner that is fair to the Company and its customers.

Q. Has PacifiCorp agreed to Staff's proposal that the variable costs of new resources be included in the RVM even if the fixed costs of the new resource are not yet in rate base?

A. Yes, with some qualifications explained by Ms. Omohundro. With this modification, PacifiCorp's RVM mechanism now addresses one of CUB's key objections.

Q. Please summarize Staff's position with regard to the Grid West costs included in this filing.

A. In his surrebuttal testimony, Staff witness Mr. Stefan Brown states that the level of ongoing Grid West costs included in the Company's filing is reasonable, and recommends that that Grid West costs be included in the Company's test year revenue requirement. Staff/1400/Brown/3. PacifiCorp's participation in Grid West is designed to protect customers by ensuring the availability of low cost, reliable transmission. A cost disallowance that would restrict PacifiCorp's participation in Grid West is not in the best interests of customers.

Q. Has any party other than ICNU contested the level of Grid West costs included in the Company's filing?

A. No. On May 4, 2005 the Company executed its first Partial Stipulation signed by ICNU, CUB, Fred Meyer, and Staff. This stipulation did not include an adjustment to Non-Labor Administrative and General Costs for Grid West. ICNU specifically reserved the right to contest RTO related costs in this proceeding.

Q. Please describe in more detail the Second and Third Partial Stipulations executed since the Company's Rebuttal filing.

A. The Second Partial Stipulation was executed on June 29, 2005 and reflects agreement between the Company, Staff, CUB, ICNU, and Fred Meyer on the level of employee benefits to be included in revenue requirement. The parties agreed to use an 85/15 cost sharing structure for employee medical benefit costs, use the Company's actual calendar 2004 medical benefit costs as the base data, and escalate these costs by 10 percent annually. The Stipulation also implemented a 10 percent escalation to costs associated with the Workers Comp Levy and allowed $750,000 in external system developments costs, amortized over two years, to be included in Other Salary Overhead. These adjustments reduce the Company's revenue requirement by $2.41 million.

The Third Partial Stipulation, also executed on June 29, 2005, reflects agreement between Staff and the Company on the amount of RVM power cost updates. This agreement would result in an approximate $4.3 million increase to the Company's revenue requirement effective January 1, 2006, if the proposed RVM is approved. The Stipulation also reflects agreement to allow the Company to correct its revenue requirement to include a fuel handling charge, an increase of $2.49 million.

Q. Does this conclude your sur-surrebuttal testimony?

A. Yes.

210 Hadaway Testimony

Case UE-170
PPL Exhibit 210
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-Surrebuttal Testimony of Samuel C. Hadaway

Cost of Equity/WACC

July 2005

Q. Are you the same Samuel C. Hadaway who previously filed direct testimony and rebuttal testimony in this proceeding?

A. Yes.

Q. What are the purposes of your testimony?

A. In large part, the surrebuttal testimony of Staff witness Mr. Morgan and of CUB/ICNU witness Mr. Gorman simply restated arguments made in their direct testimony. I have addressed such arguments in my rebuttal testimony. In this sur-surrebuttal testimony, I will address a few additional claims that were advanced in Mr. Morgan's and Mr. Gorman's latest round of testimony. Specifically, I will address (1) Mr. Morgan's response to my observation that Value Line's projections include the forecast of an average 11.5 percent return on common equity for companies in the electric utility industry, (2) Mr. Morgan's claim that the hypothetical capital structure he recommends for PacifiCorp is consistent with his projections of required returns on common equity for the comparable electric utility companies, and (3) Mr. Gorman's claims with respect to the trend in electric utility allowed returns.

<u>**Value Line's Projections of Electric Utility Returns on Common Equity**</u>

Q. In Exhibit Staff/1200/Morgan/9-10, Mr. Morgan states that Value Line's 11.5 percent forecast of ROEs, which you cite in your rebuttal testimony, is based on a much larger utility group than your group of comparable companies and that the larger group includes companies with a lot of unregulated businesses. Is the 11.5 percent figure responsive to claims in Mr. Morgan's direct testimony, and what would the comparable Value Line number be for your comparable companies?

A. The 11.5 percent number was given in direct response to testimony by Mr. Morgan. In his direct testimony, Mr. Morgan made the following statement criticizing my ROE recommendation: "It [Hadaway's ROE recommendation] is also higher than the range of reasonable returns anticipated by Value Line on a forward-looking basis, for <u>the electric utility industry</u>." (Exhibit Staff/200/Morgan/6 (emphasis added)) As I demonstrated in my rebuttal testimony, this statement was simply wrong. Value Line projects that the electric utility industry will earn an average annual ROE of 11.5 percent over the next three to five years. Furthermore, based on Mr. Morgan's Exhibit Staff/203/Morgan/14, the companies in the comparable group of companies (which is the same group of companies in both Mr. Morgan's and my analyses) are projected by Value Line to have ROEs of 10.75 to 10.80 percent—125 to 130 basis points higher than Mr. Morgan's 9.5 percent recommendation for PacifiCorp.

<u>The Applicable Capital Structures for the Comparable Companies</u>

Q. In Staff/1200/Morgan/14, Mr. Morgan argues that the allowed ROE for PacifiCorp should be matched with the current capitalization of the comparable companies used in the cost-of-equity analyses. He also claims that such a capital structure is not a "hypothetical" capital structure. Are these positions reasonable and accurate, and is Mr. Morgan's proposed capital structure consistent with other aspects of this case?

A. The answer is "no" to both questions. In the first place, Mr. Morgan's use of a capital structure for PacifiCorp other than its actual capital structure is in fact the use of a "hypothetical" capital structure, as I stated in my rebuttal testimony. Moreover, his election to use a hypothetical capital structure that is based on the historical capital structures of the comparable group of companies, ignoring their projected capital structure changes, is inconsistent with the future test year used in this case and is inconsistent with the use of an ROE model based on projected utility returns and earnings growth. Mr. Williams observed in his rebuttal testimony that the rating agencies are toughening their ratings standards, and Value Line not surprisingly projects in such a ratings environment that the comparable companies' will increase their common equity ratios from the historical levels relied on by Mr. Morgan. Similarly, the Company has committed to increasing its own equity capitalization, in a manner comparable to and to a level consistent with Value Line's projected capital structure averages for the comparable group. Mr. Morgan is inconsistent when he assumes that investors rely on Value Line's projected growth rates, while apparently at the same time assuming that the investors will not expect the earnings growth to be applied to the capital structures concurrently projected by Value Line.

Mr. Morgan also defends his hypothetical historically-based capital structure with the assertion that "attempting to estimate the 'future state' of a company, with regard to any factor, introduces bias." (Exhibit Staff/Morgan/14.) This seems to me a strange defense for ignoring Value Line's projected increases in comparable company equity ratios, given that Mr. Morgan's ROE recommendations rely so heavily on Value Line's estimate of the "future state" of earnings growth from the same forecasts for the same companies.

The Trend in Electric Utility Returns

Q. In CUB-ICNU/Gorman/404, Mr. Gorman argues that his 9.5 percent ROE recommendation reflects the recent trend in authorized utility ROEs. Is Mr. Gorman's statement correct?

A. No. As I explained in my rebuttal testimony, Mr. Gorman's 9.5 percent ROE recommendation is almost 125 basis points lower than the average allowed ROE for electric utilities in 2004 and is 94 basis points lower than the 10.44 percent ROE allowed during the first quarter of 2005. I have provided in PPL Exhibit 211 a graph and ROE "trend line" that show Mr. Gorman's claims are erroneous. As the graph shows, allowed rates of return indeed have come down over the past five years (as have my ROE recommendations), but the trend is nothing like Mr. Gorman implies, and the graph clearly demonstrates again how far out of step Mr. Gorman's and Mr. Morgan's ROE recommendations are.

Q. Does this conclude your sur-surrebuttal testimony?

A. Yes, it does.

211 Hadaway Exhibit

Case UE-170
PPL Exhibit 211
Witness: Samuel C. Hadaway

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

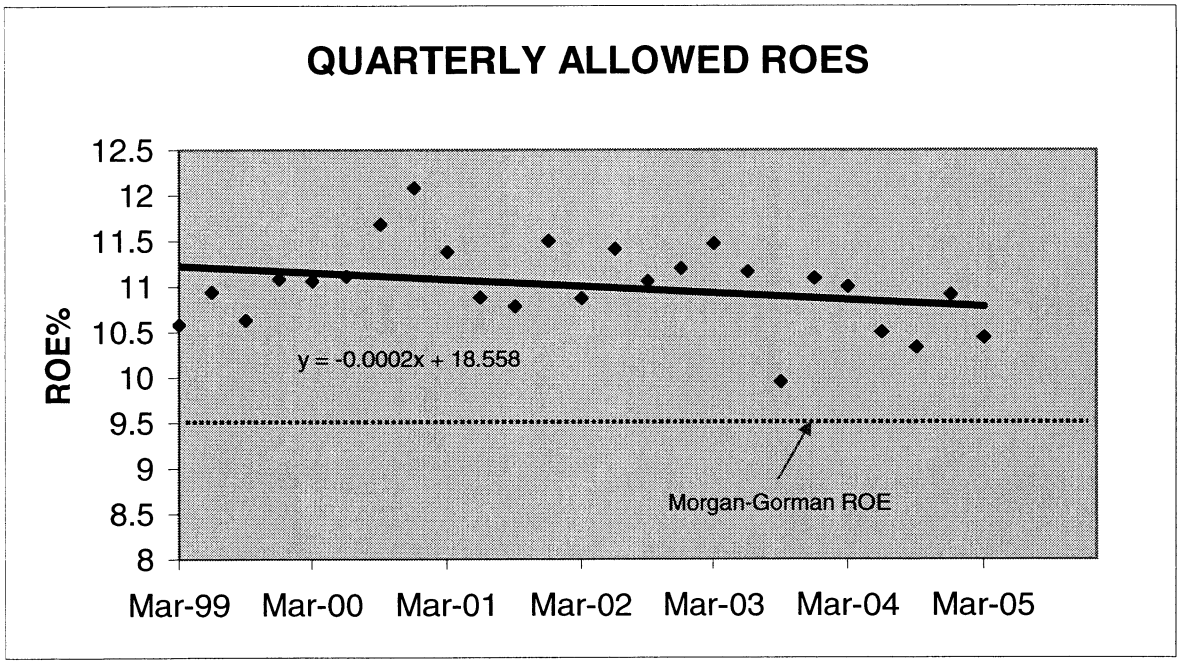
PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of Samuel C. Hadaway

Plot of Allowed Rates of Return

July 2005

PACIFICORP OREGON
PLOT OF ALLOWED RATES OF RETURN



DATA: RRA QUARTERLY ELECTRIC UTILITY ALLOWED ROES

NO	DATE	ROE
1	Mar-99	10.58
2	Jun-99	10.94
3	Sep-99	10.63
4	Dec-99	11.08
5	Mar-00	11.06
6	Jun-00	11.11
7	Sep-00	11.68
8	Dec-00	12.08
9	Mar-01	11.38
10	Jun-01	10.88
11	Sep-01	10.78
12	Dec-01	11.50
13	Mar-02	10.87
14	Jun-02	11.41
15	Sep-02	11.06
16	Dec-02	11.20
17	Mar-03	11.47
18	Jun-03	11.16
19	Sep-03	9.95
20	Dec-03	11.09
21	Mar-04	11.00
22	Jun-04	10.50
23	Sep-04	10.33
24	Dec-04	10.91
25	Mar-05	10.44

Case UE-170
PPL Exhibit 312
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-Surrebuttal Testimony of Bruce N. Williams

Cost of Equity/Preferred/Debt

July 2005

Q. Are you the same Bruce N. Williams who previously filed direct testimony and rebuttal testimony in this proceeding?

A. Yes.

Q. What are the purposes of your testimony?

A. First I will update the Company's cost of long-term debt and preferred testimony and exhibits, to reflect all known changes since I filed my direct testimony. Then I will address arguments advanced in the surrebuttal testimony of Staff witnesses Ms. Peng, Mr. Morgan, and Mr. Conway/Ms. Johnson, as well as statements made in the surrebuttal testimony of CUB/ICNU witness Mr. Gorman. My responses will address (1) the cost of the Company's preferred equity and long-term debt, (2) the overall benefits of the ScottishPower capital structure on the Company's credit ratings and the absence of support for any downward adjustment for the impacts of parent debt, (3) the known and measurable nature and the benefits of the $500 million in common equity contributions that Mr. Morgan and Mr. Gorman seek to exclude from the Company's capital structure, and (4) the importance of maintaining the Company's "A" credit ratings.

Updates to the Company's Costs of Capital

Q. Have you updated the cost of debt and preferred stock for all known and measurable changes since the filing of the Company's direct testimony?

A. Yes, I have updated the exhibits for Cost of Debt (PPL Exhibit 301) and Preferred Stock (PPL Exhibit 303) from my direct testimony with PPL Exhibits 313 and 314, respectively, to show all known and measurable changes that have occurred since the filing of the Company's direct testimony.

Q. Can you describe briefly each of the changes that have occurred since the filing of your direct testimony that impact the cost of debt and cost of preferred equity calculations?

A. Yes. PPL Exhibit 315 summarizes each of the six adjustments and their impact to the cost of debt and cost of preferred equity as filed in the Company's direct testimony. These changes reflect both actions taken by the Company after my direct testimony was filed and changes in anticipated rates for new long-term debt issuances and for the existing long-term variable-rate debt.

The first adjustment is for the 8.625% Series F First Mortgage Bonds due 12/13/24 totaling $20.0 million, redeemed prior to maturity on December 13, 2004. This series of long-term debt has been removed from the updated embedded cost of long-term debt calculation in PPL Exhibit 313.

The second adjustment is for maturity extensions executed on March 16, 2005 for three series of long-term variable-rate Pollution Control Revenue Bond obligations totaling $38.1 million. These three series of long-term debt were all originally scheduled to mature by July 1, 2006 and had been removed, in my direct testimony, from the embedded cost of debt calculation as part of the total $238.8 million of long-term debt scheduled to mature over the 12 months following March 31, 2006. (PPL/300/Williams/5) These three series of long-term variable-rate debt are now included in the updated embedded cost of long-term debt calculation (PPL Exhibit 313) at projected interest rates consistent with the methodology used in determining the rates for the Company's other tax-exempt variable-rate debt as described in my direct testimony.

(PPL/300/Williams/10)

The third adjustment is for the new long-term debt issuance made by the Company on June 13, 2005 of the 5.25 percent First Mortgage Bond Series due 6/15/35, totaling $300.0 million, the proceeds from which were used in part to reduce short-term debt that had been used temporarily to refinance the 8.625% Series F First Mortgage Bond series redemption described above. The embedded cost of debt for this new series therefore includes issuance as well as redemption costs.

The fourth adjustment reflects the election made as of the June 15, 2005 redemption date to make both the $3.75 million optional redemption, as well as the $3.75 million mandatory redemption, for the $7.48 No Par Serial Preferred Stock series. The election of the optional redemption was made after the filing of my direct testimony and was disclosed in the rebuttal testimony. (PPL/304/Williams/3)

An effect of the four adjustments described above for maturity extensions, additional redemptions, and new long-term debt issuance is a net reduction of $314.4 million from the $638.8 million of new long-term debt issuances identified in my direct testimony (PPL/300/Williams/5 lines 21-23) as needed to fund operations and to refinance both matured debt and debt that would be currently maturing at March 31, 2006.

The fifth adjustment was to update the projected interest rate for the adjusted new long-term debt. (PPL/300/Williams/11 lines 10-15) The Company's estimated June 2005 credit spread for 20-year notes is 1.05 percent.

The forward 20-year Treasury rate for March 31, 2006 is 4.46 percent. Issuance costs for this type of note add approximately 9 basis points (*i.e.* 0.09 %) to the all-in cost. Therefore the projected cost of replacement debt has been reduced to approximately 5.60 percent (1.05 % + 4.46 % + 0.09 %).

The sixth adjustment was to update the forward 30-day LIBOR rate used as a basis for determining the rates for the Company's tax-exempt long-term variable-rate debt portfolio. (PPL/300/Williams/10) The forward 30-day LIBOR rate has increased to 3.96 percent from the 3.17 percent rate used at the time of my direct testimony. Using the same methodology as in my direct testimony, the Company has applied a factor of 85 percent to this updated rate and added the respective credit enhancement and remarketing fees for each floating-rate tax-exempt bond.

Q. What is the Company's new embedded cost of long-term debt and preferred stock, given the adjustments described in response to the previous question?

A. PPL Exhibit 313 shows the embedded cost of long-term debt at March 31, 2006 at 6.288 %. PPL Exhibit 314 shows the embedded cost of preferred stock at March 31, 2006 at 6.590 %.

Q. What is the Company's new weighted average cost of long-term debt and preferred stock, given the adjustments described in response to the previous questions?

A. The weighted costs are:

PacifiCorp
Cost of Capital
March 31, 2006 Test Year

Component	Percent of Total	Cost	Weighted Average
Long Term Debt	49.44%	6.288%	3.109%
Preferred Stock	1.06%	6.590%	0.070%

Cost of Preferred Equity

Q. Please explain the differences between the Company's proposed preferred equity balance and preferred equity balance as calculated by Staff witness Ming Peng in her surrebuttal testimony.

A. As I explained in my rebuttal testimony, I used the date of March 31, 2006 consistently for the calculation of all components of the Company's 2006 test year capital structure. Each year as of June 15, the Company must make a mandatory preferred stock redemption of $3.75 million and also has the non-cumulative option to redeem up to an additional $3.75 million. When I filed my direct testimony, I included the known 2005 mandatory redemption amount to compute the preferred stock balance at March 31, 2006. After the filing of my direct testimony, the Company elected to make the optional $3.75 million redemption on June 15, 2005. In rebuttal testimony, I amended the preferred equity balance to reflect this then known post-direct testimony change, not to correct an "error" as asserted in Staff's testimony. In this testimony, I similarly have disclosed all other changes that have occurred with respect to the Company's preferred stock and long-term debt after the filing of my direct testimony.

In contrast to my exhibits, which use actual balances for preferred stock as of March 31, 2006, the Staff witness continues to calculate a balance for preferred stock as of December 31, 2006. However, in surrebuttal, the Staff witness changed her assumed number of shares outstanding for the $7.48 No Par Serial Preferred Stock series from 430,000 to 468,750. This new Staff-adjusted figure of 468,750 for shares outstanding is still incorrect, and in fact now is greater than the 450,000 shares that are currently outstanding and that will be outstanding as of March 31, 2006, as described in the Company's rebuttal testimony and reflected in PPL Exhibit 314.

Q. What accounts for the remaining differences between the Company's and the Staff's calculations of the cost of the Company's preferred equity?

A. The Company has presented a cost of preferred equity of 6.590 %. Staff has increased its calculation of the cost of the Company's preferred equity from 6.34 percent to 6.44 percent by correcting its treatment of stock issuance cost, consistent with my rebuttal testimony. The remaining difference between Company's and Staff's calculated costs arises because of Staff's continued exclusion of the unamortized expense associated with the Company's Quarterly Income Debt Securities (or "QUIDS"), which securities are combined with preferred stock in the Company's and Staff's cost-of-capital presentations. I addressed in my rebuttal testimony why such exclusion is not proper; in its surrebuttal testimony, Staff merely repeated its original arguments on this subject, without addressing my refutation of those arguments in my rebuttal testimony.

Cost of Long-Term Debt

Q. Please explain the remaining differences between the Company's and Staff's calculations of the Company's long-term debt costs.

A. PacifiCorp calculates a long-term debt cost as of March 31, 2006 of 6.288 %, based on the actual cost of its current debt, with additional debt required through March 31, 2006 priced at the cost of new 20-year "A-rated" utility bonds, using forward interest rates for the time the bonds are expected to be issued. Staff calculates a long-term debt cost as of the same date, under the unsupported assumption that forward interest rates are the same as current rates. Staff's surrebuttal testimony does respond to my rebuttal testimony by correcting Staff's errors in the calculation of unamortized redemption expense on long-term debt. However, this correction is offset by Staff's decision to change the assumption presented in its direct testimony -- that the new long-term debt will have an average 10-year life -- to a new assumption that the debt will be a mix of 5-, 7- and 10-year bonds. The resulting Staff-calculated cost of debt is 6.14 percent.

Q. In continuing to ignore the forward cost projections for future debt to be issued by the Company, does Staff in surrebuttal address the arguments in your rebuttal testimony as to why Staff's refusal to use forward interest rate expectations can be expected to understate the cost of future debt issuances?

A. No. Staff does not address my testimony on this issue.

Q. Is Staff's assumption that PacifiCorp's debt issuances between now and March 31, 2006 will be issued at the average of 5-, 7- and 10-year bond rates reasonable?

A. No. As I explained in my rebuttal testimony, the assumed 10-year term of new debt contained in Staff's direct case was itself unreasonably low, given that the reasonable expectation is for PacifiCorp to issue bonds with an average life of 20 years. I also pointed out that in fact the average life of the Company's long-term bonds issued in 2004 was 20 years. Staff in surrebuttal adopted an even more unreasonable bond term, without addressing the actual terms of the Company's bonds or my testimony as to why a 20-year average term was appropriate.

Q. Would you please comment on Staff's rationale for assuming, in its surrebuttal testimony, an even shorter term for the Company's 10-year debt issuances than its original 10-year assumption?

A. The witness based the reduction solely on an assertion that use of a 10-year average bond life was inconsistent with Commission policy:

> "However, upon further reflection and review of prior commission cases, using a 10-year maturity is inconsistent with past Commission policy. The historical practice by Commission staff, and adopted by the Commission is to use the average of 5-, 7- and 10-year terms."

Exhibit Staff/1300/Ming Peng/5. I find this rationale puzzling, given the Commission's conclusions on this issue in the Company's last rate case. In that case, Staff proposed, and the Commission rejected, use of a 7-year assumed term for the Company's future debt issuances. In its order, the Commission assumed a 10-year average term. For the reasons set forth in my rebuttal testimony, because of the near-term interest environment, the assumption most in accord with current reality would be that the new bonds will be issued an average 20-year life.

<u>The Overall Benefits of the ScottishPower Capital Structure on the Company's Credit Ratings and the Absence of Support for any Downward Adjustment for the Impacts on the Company of PHI Debt</u>

Q. Would you comment generally on the analysis used by Mr. Conway and Ms. Johnson to justify a proposed $4.6 million reduction to PacifiCorp's revenue requirement for a supposed negative impact of ScottishPower on PacifiCorp's credit ratings?

A. Yes. The analysis proceeds from an incorrect premise, is wholly speculative and unsupported, and is incorrect in method.

Q. What is the incorrect premise?

A. The incorrect premise is that the Commission's ring-fencing of PacifiCorp's operations may not have been fully effective. The purpose of such ring-fencing is not to deal with any one issue of parent debt, such as the PHI debt, but to protect PacifiCorp's customers against negative economic consequences of an affiliation with ScottishPower. Merger Condition No. 7 declares that the relevant comparison is whether PacifiCorp's capital financing costs have increased by virtue of the merger with ScottishPower:

> "ScottishPower and PacifiCorp agree that in future Commission proceedings, they will not seek a higher cost of capital than that which PacifiCorp would have been authorized on its own. Specifically, no capital financing costs (either debt or equity) should increase by virtue of the fact that PacifiCorp was merged with ScottishPower."

Merger Condition No. 10, cited in the Conway/Johnson surrebuttal, states that the correct comparison is whether customers are held harmless overall:

> "ScottishPower/PacifiCorp guarantee that the customers of PacifiCorp shall be held harmless if the merger between ScottishPower and PacifiCorp results in a higher revenue requirement for PacifiCorp than if the merger had not occurred..."

As I explained in my rebuttal testimony, the credit agencies have made it unambiguously clear that the merger with ScottishPower has in fact <u>improved</u> PacifiCorp's credit evaluation, and thus the merger has made possible a <u>lower</u> cost of capital than if the merger had not occurred. Moreover, Mr. Conway and Ms. Johnson acknowledge that they agree with my analysis on this matter:

> "Taken together, we conclude that Pacificorp's ratings suffer due to debt at PHI but, PacifiCorp's ratings are currently benefited by PacifiCorp's relation to ScottishPower."

Exhibit Staff/1000/Conway-Johnson/8. Absent a showing of a negative credit impact from the affiliation with ScottishPower (as opposed to the positive impact that in fact exists), there is no basis for making any adjustment for hypothetical impacts of one issue of parent debt, divorced from the impacts of such debt as part of the total parent capital structure.

Q. Why do you say the Staff analysis is speculative?

A. The witnesses themselves acknowledge this fact. I note the following passages from the Conway/Johnson surrebuttal testimony.

> "Q. Have the ring fencing provisions, including the harmless conditions, insulated customers from PacifiCorp's parent?
> A. Perhaps..." (Exhibit Staff/1000/Conway-Johnson/6)

> "[t]his complexity ensures that any assertion by Staff and Intervenors that the acquisition would lead to a higher PGE debt cost would likely be met with a response that such an assertion is overly simplistic. Also establishing a precise

> increase in debt cost, as implementation of the 'hold harmless' condition requires, would be a difficult and contentious task with uncertain results." (Exhibit Staff/1000/Conway-Johnson/11 (quoting Commission))
>
> "Q. Do you consider this a precise estimate of the impact of PHI's debt on PacifiCorp's cost of debt?
> A. No, for the reasons discussed above." (Exhibit Staff/1000/Conway-Johnson/14)

Q. How is the analysis incorrect in method?

A. The analysis purports to calculate the impact on PacifiCorp if the PHI parent debt were included by credit agencies in the calculation of bond rating ratios for PacifiCorp. I have reviewed the calculations that both Standard & Poor's and Moody's perform during their rating analysis of PacifiCorp. I have never seen them make any debt adjustment related to the debt of PHI, ScottishPower, or any other affiliate when calculating debt ratios used to rate PacifiCorp's debt. This observation can be confirmed by reviewing the calculations contained in the rating agencies' publications. For example, in its May 27, 2005 Credit Opinion, Moody's calculations are entirely based on only PacifiCorp's capital and earnings. Any calculation based on a non-existent attribution of PHI debt in calculating PacifiCorp's ratios is fallacious and cannot logically be the basis for a reduction in PacifiCorp's revenue requirement.

Although the analysis is fallacious in its premise, I should also point out other factual errors in the analysis. First, PacifiCorp's and ScottishPower' unsecured debt ratings are BBB+, not BBB- as assumed in the testimony. (Exhibit Staff/1000/Conway-Johnson/9, 14) The analysis also uses benchmarks that are no longer relevant. Standard & Poor's published new benchmarks in June 2004. Among the changes are a deletion of the pre-tax interest coverage benchmark and a new scale of required coverages. Thus the analysis also is inconsistent with how the rating agencies actually calculate the ratios for PacifiCorp.

Q. Do you also dispute statements in this surrebuttal testimony related to the impact of the debt of PacifiCorp's parent companies?

A. Yes. Mr. Conway and Ms. Johnson, at page 6 of their surrebuttal testimony, inaccurately summarize earlier testimony by CUB as demonstrating that "PacifiCorp's ratings have suffered due to credit concerns at the parent". This summary is neither an accurate conclusion from the testimony cited nor factually defensible. As I pointed out in my rebuttal testimony, the rating agencies have been very clear that the association with ScottishPower has been a benefit to PacifiCorp. As I further explained in my rebuttal testimony, the ScottishPower affiliation has resulted in PacifiCorp ratings that likely are higher than they would otherwise be. Clearly the ScottishPower affiliation has benefited customers through lower borrowing costs. Claims to the contrary are simply unsupported and unsupportable.

Q. Finally, Mr. Conway and Ms. Johnson speculated in their rebuttal testimony that "[p]erhaps a high dividend payout requirement at ScottishPower resulted in increased demands for cash at PacifiCorp and depressed PacifiCorp's credit metrics. Has ScottishPower demanded increased dividends from PacifiCorp and thereby depressed the credit metrics?

A. No. In fact, just the opposite is true. Dividends have been reduced from levels prior to the merger with ScottishPower. In addition, PacifiCorp suspended its regular dividend declaration and payment of $80 million per quarter to ScottishPower during fiscal 2003 in an effort to rebuild the credit metrics following the western power crisis. While also forgoing dividends, ScottishPower contributed an additional $150 million of new common equity into PacifiCorp during December 2002. ScottishPower currently is contributing to PacifiCorp $125 million in new equity each calendar quarter, notwithstanding the efforts of another Staff witness to compute PacifiCorp's capital structure as if the contributions were not being made. In April 2003, PacifiCorp resumed its dividend payments at a quarterly rate of $40 million, half the rate it was paying before the dividend suspension; subsequent to April 2003, the quarterly dividend has increased in steps to its current quarterly rate of $51 million. The actions of ScottishPower have been highly supportive of PacifiCorp's credit quality.

The Known and Measurable Nature and the Benefits of the $500 Million in Common Equity Contributions Being Made by Scottish Power

Q. Mr. Gorman, at page 2 of his surrebuttal testimony, defended his excluding from PacifiCorp's capital structure of $500 million in new common equity contributions scheduled to be made by ScottishPower on or before May 31, 2006, on the grounds that "PacifiCorp has not provided a means to verify that the proposed equity infusion will actually be made." How can PacifiCorp verify that such contribution will be made and is "known and measurable"?

A. The Stock Purchase Agreement by and among ScottishPower, PHI, and MidAmerican Energy Holdings Company, dated May 23, 2005, actually requires that these contributions be made. As stated at section 4.2 of that agreement:

> "Covenants of the Seller Parent and Seller. At all times from and after the date hereof until the Closing, the Seller Parent and the Seller, jointly and severally, covenant and agree that (except as required, or expressly permitted, by this Agreement, as set forth in Section 4.1 of the Seller Parent Disclosure Letter, or to the extent that the Buyer shall otherwise previously consent in writing, which consent (except as provided in Section 4.1(a)(viii)) shall not be unreasonably withheld, conditioned or delayed) they shall:
>
> (a) (i) make a cash capital contribution to the Company (for no consideration) (x) on or before the last day of June, September, December and March in the Company's fiscal year ending March 31, 2006 equal to $125 million; provided, that if the Closing occurs prior to the end of any fiscal quarter in the fiscal year ending March 31, 2006, a cash capital contribution shall be made at Closing in an amount equal to the product of $125 million and a fraction (the '**Pro-Ration Fraction**') with a numerator equal to the number of days elapsed in such quarter and a denominator equal to the number of days in such quarter; and (y) on or before the last day of June, September, December and March in the Company's fiscal year ending March 31, 2007 equal to $131.25 million;"

In accordance with this agreement, in fact, the first quarterly equity contribution installment, in the required amount of $125 million, has already been paid. PacifiCorp received these funds from PHI on June 30, 2005. The remaining contributions are both approved by the Commission and contractually committed.

Q. Mr. Gorman, at page 3 of his surrebuttal testimony, also defended the exclusion of the $500 million contribution by asserting that the equity infusion "will only have a positive credit rating effect if it reduces the overall leverage risk that Standard & Poor's takes into account in establishing PacifiCorp's credit rating." Is this statement accurate?

A. No. PacifiCorp's credit rating is computed on a company-stand-alone basis. Although the existence of a strong parent in ScottishPower can and does provide a credit boost, the importance of the equity contribution lies in the fact that it provides improved coverage for PacifiCorp's rated first mortgage bonds. An advantage of ring-fencing, as established by the Commission, is that such capital contributions do in fact directly provide additional protection for PacifiCorp's bondholders, and thus enhance its bond ratings metrics; otherwise, there would be no reason for the Commission to insist on minimum equity requirements for ring-fenced utilities.

The rating agencies have affirmed the benefit to PacifiCorp of the equity contributions. In its May 26, 2005 rating action report, Moody's said, "The rating affirmation considers the expected continuation of equity support from its current indirect parent, SP ..."

The Importance of Maintaining the Company's "A" Credit Rating

Q. In response to your concerns about the impact of Staff's common equity return recommendation on PacifiCorp's bond ratings, Staff witness Thomas Morgan stated at page 12 of his surrebuttal testimony that "[i]t would not be appropriate to attempt to set the cost of capital based on the maintenance of any specific credit rating category." Do you agree?

A. No. To the contrary, I believe that it is important that the Commission support the Company's efforts to maintain its "A-level" bond rating. As I discussed in my direct testimony, there is a direct benefit to customers from reducing the cost of current and future borrowings. There are additional benefits as well. For example, higher-rated companies are more likely to be able to access the capital markets, particularly during periods of capital-markets disruptions. This is very important to PacifiCorp as we face a need to raise new capital in order to fund a significant period of high levels of capital expenditures, in order to ensure continued safe and reliable electric service. Failure to access the markets could lead to inability to obtain on a timely and adequate basis the new generation or other necessary transmission and distribution system enhancements that our customers will need. Further, our present ratings are important to support our ability to transact in the long-term markets for power purchases and sales. These purchases and sales provide important benefits to our customers. In addition, strong ratings help reduce the amount of costly collateral requirements that are a fact in today's credit-sensitive power markets. We know that regulated utilities indeed can lose their investment-grade bond ratings, with serious consequences. A decision to push PacifiCorp closer to the loss of its investment-grade rating, in order to achieve a relatively small short-term reduction in revenue requirement, would in my opinion be short-sighted and risky.

Q. In response to your correction of the ratings ratios that Mr. Gorman asserted PacifiCorp could achieve with his recommended 9.5 percent ROE, Mr. Gorman stated, at page 12 of his surrebuttal testimony, that you have "provided no evidence of how Standard & Poor's arrived at this debt equivalence and whether or not it is based on PacifiCorp, PHI, or ScottishPower." How do you respond?

A. I attach as PPL Exhibit 316 a copy of Standard & Poor's Research Summary of 05-May-2005. This document explicitly explains that an imputed debt of $570 million has been calculated and applied by Standard & Poor's to determine

PacifiCorp's rating metrics. The document states that the amount is an addition to PacifiCorp's (and not PHI's or ScottishPower's) balance sheet, to reflect the effect of PacifiCorp's long-term power purchase agreements and operating leases. The document also explains how Standard & Poor's arrived at the $570 million number.

Q. Does this conclude your sur-surrebuttal testimony?

A. Yes, it does.

313 Williams Exhibit

Case UE-170
PPL Exhibit 313
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of Bruce N. Williams

Pro Forma Cost of Debt Summary

July 2005

Pro Forma Cost of Debt Summary (less current maturities) - Direct Testimony Update - exhibit 313
As of March 31, 2006

DESCRIPTION	AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	SEGMENT	Coupon*	Weighted Average Maturity
Subtotal - First Mortgage Bonds	$2,329,664,000	($24,334,606)	($13,231,634)	$2,292,097,760	$146,276,317	6.279%	6.067%	15.44
Subtotal - Medium-Term Notes	$949,500,000	($10,708,983)	($26,756,479)	$912,034,537	$72,347,695	7.620%	6.507%	9.38
Total First Mortgage Bonds	$3,279,164,000	($35,043,590)	($39,988,113)	$3,204,132,297	$218,624,012	6.667%	6.195%	13.69
Subtotal - Pollution Control Obligations secured by First Mortgage Bonds	$398,394,119	($10,560,810)	($9,550,194)	$378,283,115	$17,984,331	4.514%	3.880%	15.83
Subtotal - Pollution Control Revenue Bonds	$337,900,000	($4,231,330)	($7,621,229)	$326,047,441	$15,865,609	4.695%	3.465%	12.06
Total PCRBs	$736,294,119	($14,792,139)	($17,171,423)	$704,330,557	$33,849,940	4.597%	3.690%	14.10
Total Cost of Long Term Debt	$4,015,458,119	($49,835,729)	($57,159,537)	$3,908,462,854	$252,473,952	6.288%	5.735%	13.76

PACIFICORP
Electric Operations
Pro Forma Cost of Debt Summary (less current maturities) - Direct Testimony Update - exhibit 313
March 31, 2006

LINE NO.	BOND INTEREST RATE (1)	DESCRIPTION (2)	MATURITY DATE	ORIGINAL LIFE (3)	PRINCIPAL AMOUNT ORIGINAL ISSUE (4)	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING (5)	ISSUANCE EXPENSES (6)	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT (7)	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT (8)	COST OF MONEY TO COMPANY (BOND TABLE BASIS) (9)	ANNUAL DEBT SERVICE COST (10)	LINE NO.
		First Mortgage Bonds											
1	4.300%	Series due Sep 2008	09/15/08	5	$200,000,000	$200,000,000	($1,610,660)	($5,967,819)	$192,421,521	96.211%	5.170%	$10,340,000	1
2	6.900%	Series due Nov 2011	11/15/11	10	$500,000,000	$500,000,000	($5,338,849)	$0	$494,661,151	98.932%	7.051%	$35,255,000	2
3	5.450%	Series due Sep 2013	09/15/13	10	$200,000,000	$200,000,000	($1,654,660)	($5,967,819)	$192,377,521	96.189%	5.961%	$11,922,000	3
4	4.950%	Series due Aug 2014	08/15/14	10	$200,000,000	$200,000,000	($2,168,134)	$0	$197,831,866	98.916%	5.090%	$10,180,000	4
5	7.700%	Series due Nov 2031	11/15/31	30	$300,000,000	$300,000,000	($3,701,310)	$0	$296,298,690	98.766%	7.807%	$23,421,000	5
6	5.900%	Series due Aug 2034	08/15/34	30	$200,000,000	$200,000,000	($2,612,134)	$0	$197,387,866	98.694%	5.994%	$11,988,000	6
7	5.250%	Series due Jun 2035	06/15/35	30	$300,000,000	$300,000,000	($4,005,000)	($1,295,995)	$294,699,005	98.233%	5.369%	$16,107,000	7
8	5.510%	Pro Forma Series	03/31/26	20	$324,386,000	$324,386,000	($3,243,860)	$0	$321,142,140	99.000%	5.594%	$18,146,153	8
9	8.271%	C-U Series due Oct 2010 (a)	10/01/10	18	$48,972,000	$16,945,000	$0	$0	$16,945,000	100.000%	8.271%	$1,401,521	9
10	7.978%	C-U Series due Oct 2011 (a)	10/01/11	19	$4,422,000	$1,770,000	$0	$0	$1,770,000	100.000%	7.978%	$141,211	10
11	8.493%	C-U Series due Oct 2012 (a)	10/01/12	20	$19,772,000	$9,230,000	$0	$0	$9,230,000	100.000%	8.493%	$783,904	11
12	8.797%	C-U Series due Oct 2013 (a)	10/01/13	21	$16,203,000	$8,467,000	$0	$0	$8,467,000	100.000%	8.797%	$744,842	12
13	8.734%	C-U Series due Oct 2014 (a)	10/01/14	22	$28,218,000	$15,952,000	$0	$0	$15,952,000	100.000%	8.734%	$1,393,248	13
14	8.294%	C-U Series due Oct 2015 (a)	10/01/15	23	$46,946,000	$27,903,000	$0	$0	$27,903,000	100.000%	8.294%	$2,314,275	14
15	8.635%	C-U Series due Oct 2016 (a)	10/01/16	24	$18,750,000	$11,959,000	$0	$0	$11,959,000	100.000%	8.635%	$1,032,660	15
16	8.470%	C-U Series due Oct 2017 (a)	10/01/17	25	$19,609,000	$13,052,000	$0	$0	$13,052,000	100.000%	8.470%	$1,105,504	16
17	6.067%	Subtotal - First Mortgage Bonds				**$2,329,664,000**	**($24,334,606)**	**($13,231,634)**	**$2,292,097,760**			**$146,276,317**	17

(a) Principal amortizes every October.

PACIFICORP
Electric Operations
Pro Forma Cost of Debt Summary (less current maturities) - Direct Testimony Update - exhibit 313
March 31, 2006

LINE NO.	BOND INTEREST RATE (1)	DESCRIPTION (2)	MATURITY DATE	ORIGINAL LIFE (3)	PRINCIPAL AMOUNT: ORIGINAL ISSUE (4)	PRINCIPAL AMOUNT: CURRENTLY OUTSTANDING (5)	ISSUANCE EXPENSES (6)	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY: TOTAL DOLLAR AMOUNT (7)	NET PROCEEDS TO COMPANY: PER $100 PRINCIPAL AMOUNT (8)	MONEY TO COMPANY (BOND TABLE BASIS) (9)	ANNUAL DEBT SERVICE COST (10)	LINE NO.
1		**Series C MTNs**											1
2	9.150%	Series C due Aug 2011	08/09/11	20	$8,000,000	$8,000,000	($75,327)	$0	$7,924,673	99.058%	9.254%	$740,320	2
3	8.950%	Series C due Sep 2011	09/01/11	20	$20,000,000	$20,000,000	($132,118)	$0	$19,867,882	99.339%	9.022%	$1,804,400	3
4	8.920%	Series C due Sep 2011	09/01/11	20	$20,000,000	$20,000,000	($188,318)	$0	$19,811,682	99.058%	9.023%	$1,804,600	4
5	8.950%	Series C due Sep 2011	09/01/11	20	$25,000,000	$25,000,000	($175,398)	$0	$24,824,602	99.298%	9.026%	$2,256,500	5
6	8.290%	Series C due Dec 2011	12/30/11	20	$3,000,000	$3,000,000	($23,040)	($410,784)	$2,566,175	85.539%	9.972%	$299,160	6
7	8.260%	Series C due Jan 2012	01/10/12	20	$1,000,000	$1,000,000	($7,649)	($136,928)	$855,423	85.542%	9.938%	$99,380	7
8	8.280%	Series C due Jan 2012	01/10/12	20	$2,000,000	$2,000,000	($13,297)	($273,856)	$1,712,847	85.642%	9.947%	$198,940	8
9	8.250%	Series C due Feb 2012	02/01/12	20	$3,000,000	$3,000,000	($22,946)	($410,784)	$2,566,270	85.542%	9.927%	$297,810	9
10	8.530%	Series C due Dec 2021	12/16/21	30	$15,000,000	$15,000,000	($115,202)	($2,053,922)	$12,830,877	85.539%	10.066%	$1,509,900	10
11	8.375%	Series C due Dec 2021	12/31/21	30	$5,000,000	$5,000,000	($38,400)	($684,641)	$4,276,959	85.539%	9.889%	$494,450	11
12	8.260%	Series C due Jan 2022	01/07/22	30	$5,000,000	$5,000,000	($33,243)	($684,641)	$4,282,117	85.642%	9.745%	$487,250	12
13	8.270%	Series C due Jan 2022	01/10/22	30	$4,000,000	$4,000,000	($30,594)	($547,712)	$3,421,693	85.542%	9.768%	$390,720	13
14		**Sub-Total Series C**				**$111,000,000**	**($855,533)**	**($5,203,268)**	**$104,941,200**			**$10,383,430**	14
15													15
16		**Series E MTNs**											16
17	7.430%	Series E due Sep 2007	09/11/07	15	$2,000,000	$2,000,000	($15,530)	($226,075)	$1,758,395	87.920%	8.905%	$178,100	17
18	7.220%	Series E due Sep 2007	09/18/07	15	$2,500,000	$2,500,000	($19,412)	($282,594)	$2,197,994	87.920%	8.675%	$216,875	18
19	7.270%	Series E due Sep 2007	09/24/07	15	$4,000,000	$4,000,000	($31,059)	($452,151)	$3,516,790	87.920%	8.730%	$349,200	19
20	8.130%	Series E due Jan 2013	01/22/13	20	$10,000,000	$10,000,000	($75,827)	($671,687)	$9,252,486	92.525%	8.939%	$893,900	20
21	8.050%	Series E due Sep 2022	09/01/22	30	$15,000,000	$15,000,000	($131,471)	($1,695,566)	$13,172,963	87.820%	9.258%	$1,388,700	21
22	8.070%	Series E due Sep 2022	09/09/22	30	$8,000,000	$8,000,000	($70,118)	($904,302)	$7,025,580	87.820%	9.280%	$742,400	22
23	8.110%	Series E due Sep 2022	09/09/22	30	$12,000,000	$12,000,000	($105,177)	($1,356,453)	$10,538,370	87.820%	9.325%	$1,119,000	23
24	8.120%	Series E due Sep 2022	09/09/22	30	$50,000,000	$50,000,000	($438,238)	($5,651,887)	$43,909,875	87.820%	9.336%	$4,668,000	24
25	8.050%	Series E due Sep 2022	09/14/22	30	$10,000,000	$10,000,000	($87,648)	($1,130,377)	$8,781,975	87.820%	9.258%	$925,800	25
26	8.080%	Series E due Oct 2022	10/14/22	30	$25,000,000	$25,000,000	($200,190)	($2,061,627)	$22,738,182	90.953%	8.953%	$2,238,250	26
27	8.080%	Series E due Oct 2022	10/14/22	30	$26,000,000	$26,000,000	($208,198)	($2,938,981)	$22,852,821	87.895%	9.283%	$2,413,580	27
28	8.230%	Series E due Jan 2023	01/20/23	30	$4,000,000	$4,000,000	$51,229	($88,989)	$3,962,241	99.056%	8.316%	$332,640	28
29	8.230%	Series E due Jan 2023	01/20/23	30	$5,000,000	$5,000,000	($37,914)	($335,843)	$4,626,243	92.525%	8.951%	$447,550	29
30		**Sub-Total Series E**				**$173,500,000**	**($1,369,553)**	**($17,796,533)**	**$154,333,914**			**$15,913,995**	30
31													31
32		**Series F MTNs**											32
33	7.260%	Series F due Jul 2023	07/21/23	30	$11,000,000	$11,000,000	($100,622)	($589,062)	$10,310,316	93.730%	7.804%	$858,440	33
34	7.260%	Series F due Jul 2023	07/21/23	30	$27,000,000	$27,000,000	($246,981)	($1,445,880)	$25,307,139	93.730%	7.804%	$2,107,080	34
35	7.230%	Series F due Aug 2023	08/16/23	30	$15,000,000	$15,000,000	($137,211)	($268,624)	$14,594,165	97.294%	7.457%	$1,118,550	35
36	7.240%	Series F due Aug 2023	08/16/23	30	$30,000,000	$30,000,000	($274,423)	($537,248)	$29,188,329	97.294%	7.467%	$2,240,100	36
37	6.750%	Series F due Sep 2023	09/14/23	30	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	99.235%	6.810%	$136,200	37
38	6.720%	Series F due Sep 2023	09/14/23	30	$2,000,000	$2,000,000	($15,300)	$0	$1,984,700	99.235%	6.780%	$135,600	38
39	6.750%	Series F due Sep 2023	09/14/23	30	$5,000,000	$5,000,000	($38,250)	($34,169)	$4,927,581	98.552%	6.865%	$343,250	39
40	6.750%	Series F due Oct 2023	10/26/23	30	$12,000,000	$12,000,000	($91,396)	$0	$11,908,604	99.238%	6.810%	$817,200	40
41	6.750%	Series F due Oct 2023	10/26/23	30	$16,000,000	$16,000,000	($121,861)	$0	$15,878,139	99.238%	6.810%	$1,089,600	41
42	6.750%	Series F due Oct 2023	10/26/23	30	$20,000,000	$20,000,000	($152,326)	$0	$19,847,674	99.238%	6.810%	$1,362,000	42
43		**Sub-Total Series F**				**$140,000,000**	**($1,193,670)**	**($2,874,983)**	**$135,931,347**			**$10,208,020**	43

PACIFICORP
Electric Operations
Pro Forma Cost of Debt Summary (less current maturities) - Direct Testimony Update - exhibit 313
March 31, 2006

LINE NO.	BOND INTEREST RATE	DESCRIPTION	MATURITY DATE	ORIGINAL LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	MONEY TO COMPANY (BOND TABLE BASIS)	ANNUAL DEBT SERVICE COST	LINE NO.
	(1)	(2)		(3)	(4)	(5)	(6)		(7)	(8)	(9)	(10)	
44													44
45		**Series G MTNs**											45
46	6.625%	Series G due Jun 2007	06/01/07	12	$100,000,000	$100,000,000	($1,897,428)	($881,696)	$97,220,876	97.221%	6.971%	$6,971,000	46
47	6.710%	Series G due Jan 2026	01/15/26	30	$100,000,000	$100,000,000	($904,467)	$0	$99,095,533	99.096%	6.781%	$6,781,000	47
48		**Sub-Total Series G**				**$200,000,000**	**($2,801,895)**	**($881,696)**	**$196,316,409**			**$13,752,000**	48
49													49
50		**Series H MTNs**											50
51	6.375%	Series H due May 2008	05/15/08	10	$200,000,000	$200,000,000	($2,060,179)	$0	$197,939,821	98.970%	6.517%	$13,034,000	51
52	7.000%	Series H due Jul 2009	07/15/09	12	$125,000,000	$125,000,000	($2,428,154)	$0	$122,571,846	98.057%	7.245%	$9,056,250	52
53		**Sub-Total Series H**				**$325,000,000**	**($4,488,333)**	**$0**	**$320,511,667**			**$22,090,250**	53
54													54
55													55

PACIFICORP
Electric Operations
Pro Forma Cost of Debt Summary (less current maturities) - Direct Testimony Update - exhibit 313
March 31, 2006

LINE NO.	BOND INTEREST RATE	DESCRIPTION	ISSUE DATE	MATURITY DATE	ORIGINAL LIFE	PRINCIPAL AMOUNT ORIGINAL ISSUE	PRINCIPAL AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY TOTAL DOLLAR AMOUNT	NET PROCEEDS TO COMPANY PER $100 PRINCIPAL AMOUNT	COST OF MONEY TO COMPANY (BOND TABLE BASIS)	ANNUAL DEBT SERVICE COST	LINE NO.
	(1)	(2)			(3)	(4)	(5)	(6)		(7)	(8)	(9)	(10)	
		SECURED POLLUTION CONTROL REVENUE BONDS												
1	5.650%	Emery County due Nov 2023	11/15/93	11/01/23	30	$46,500,000	$46,500,000	($1,624,793)	($2,842,053)	$42,033,154	90.394%	6.501%	$3,022,965	1
2	5.625%	Emery County due Nov 2023	11/15/93	11/01/23	30	$16,400,000	$16,400,000	($1,015,051)	($819,557)	$14,565,392	88.813%	6.606%	$1,083,384	2
3	5.625%	Lincoln County due Nov 2021	11/15/93	11/01/21	28	$8,300,000	$8,300,000	($426,105)	($414,778)	$7,459,117	89.869%	6.538%	$542,654	3
4	3.900%	Converse 88 due Jan 2014	01/01/88	01/01/14	30	$17,000,000	$17,000,000	($155,970)	($579,849)	$16,264,181	95.672%	4.258%	$723,860	4
5	3.900%	Sweetwater 84C due Dec 2014	12/12/84	12/01/14	30	$15,000,000	$15,000,000	($227,887)	$0	$14,772,113	98.481%	4.090%	$613,500	5
6	3.400%	Lincoln 91 due Jan 2016	01/17/91	01/01/16	25	$45,000,000	$45,000,000	($771,836)	($2,578,602)	$41,649,562	92.555%	4.121%	$1,854,450	6
7	4.125%	Forsyth 86A due Dec 2016 (a)	12/29/86	12/01/16	30	$8,500,000	$8,500,000	($304,824)	$0	$8,195,176	96.414%	4.446%	$377,910	7
8	4.125%	Converse 95 due Nov 2025 (a)	11/17/95	11/01/25	30	$5,300,000	$5,300,000	($132,043)	$0	$5,167,957	97.509%	4.380%	$232,140	8
9	4.125%	Lincoln 95 due Nov 2025 (a) (b)	11/17/95	11/01/25	30	$22,000,000	$19,924,119	($404,262)	$0	$19,519,857	97.971%	4.457%	$888,018	9
10	3.360%	Carbon County due Nov 2024	11/17/94	11/01/24	30	$9,365,000	$9,365,000	($206,519)	($58,574)	$9,099,907	97.169%	3.812%	$356,994	10
11	3.360%	Converse County due Nov 2024	11/17/94	11/01/24	30	$8,190,000	$8,190,000	($209,778)	($86,323)	$7,893,899	96.385%	3.857%	$315,888	11
12	3.360%	Emery County due Nov 2024	11/17/94	11/01/24	30	$121,940,000	$121,940,000	($3,274,246)	($1,925,767)	$116,739,987	95.736%	4.112%	$5,014,173	12
13	3.360%	Lincoln County due Nov 2024	11/17/94	11/01/24	30	$15,060,000	$15,060,000	($422,858)	($81,427)	$14,555,715	96.651%	3.933%	$592,310	13
14	3.360%	Moffat County due May 2013	11/17/94	05/01/13	19	$40,655,000	$40,655,000	($874,159)	($74,912)	$39,705,929	97.666%	3.827%	$1,555,867	14
15	3.360%	Sweetwater County due Nov 2024	11/17/94	11/01/24	30	$21,260,000	$21,260,000	($510,479)	($88,352)	$20,661,169	97.183%	3.811%	$810,219	15
16	3.880%	**Total - Secured Pollution Control Revenue Bonds**				**$400,470,000**	**$398,394,119**	**($10,560,810)**	**($9,550,194)**	**$378,283,115**			**$17,984,331**	16
17														17
18		UNSECURED POLLUTION CONTROL REVENUE BONDS												18
19	3.360%	Sweetwater 88B due Jan 2014	01/01/88	01/01/14	30	$11,500,000	$11,500,000	($84,822)	($392,250)	$11,022,928	95.852%	4.730%	$543,950	19
20	3.360%	Sweetwater 90A due Jul 2015	07/24/90	07/01/15	25	$70,000,000	$70,000,000	($660,750)	($795,122)	$68,544,128	97.920%	4.607%	$3,224,900	20
21	3.360%	Emery 91 due Jan 2015	05/22/91	01/01/16	25	$45,000,000	$45,000,000	($872,505)	($2,568,859)	$41,558,636	92.353%	5.084%	$2,287,800	21
22	3.360%	Sweetwater 88A due Jan 2017	01/01/88	01/01/17	30	$50,000,000	$50,000,000	($422,443)	($882,101)	$48,695,456	97.391%	4.708%	$2,354,000	22
23	3.360%	Forsyth 88B due Jan 2018	01/01/88	01/01/18	30	$45,000,000	$45,000,000	($380,198)	($1,013,283)	$43,606,519	96.903%	4.663%	$2,098,350	23
24	3.360%	Gillette 88 due Jan 2018	01/01/88	01/01/18	30	$63,000,000	$41,200,000	($351,905)	($1,006,013)	$39,842,082	96.704%	4.675%	$1,926,100	24
25	3.360%	Converse 92 due Jul 2006	09/29/92	12/01/20	28	$22,485,000	$22,485,000	($205,065)	($303,303)	$21,976,632	97.739%	3.820%	$858,927	25
26	3.360%	Sweetwater 92A due Apr 2005	09/29/92	12/01/20	28	$9,335,000	$9,335,000	($152,123)	($134,094)	$9,048,783	96.934%	3.868%	$361,078	26
27	3.360%	Sweetwater 92B due Dec 2005	09/29/92	12/01/20	28	$6,305,000	$6,305,000	($141,505)	($97,735)	$6,065,760	96.206%	3.912%	$246,652	27
28	3.360%	Sweetwater 95 due Nov 2025 (a)	11/17/95	11/01/25	30	$24,400,000	$24,400,000	($225,000)	($428,469)	$23,746,531	97.322%	4.631%	$1,129,964	28
29	6.150%	Emery 96 due Sep 2030	09/24/96	09/30/30	34	$12,675,000	$12,675,000	($735,013)	$0	$11,939,987	94.201%	6.579%	$833,888	29
30	3.465%	**Total - Unsecured Pollution Control Revenue Bonds**				**$359,700,000**	**$337,900,000**	**($4,231,330)**	**($7,621,229)**	**$326,047,441**			**$15,865,609**	30
31														31
32		(a) Subject to Alternative Minimum Tax.												32
33		Annual Debt Service (column 10) includes remarketing fees and credit enhancement fees.												33
34		(b) Currently outstanding amounts are shown net of construction fund balances.												34
35														35

314 Williams Exhibit

Case UE-170
PPL Exhibit 314
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of Bruce N. Williams

Pro Forma Cost of Preferred Stock

July 2005

PACIFICORP
Electric Operations
Pro Forma Cost of Preferred Stock - Direct Testimony Update - exhibit 314
March 31, 2006

Line No.	Description of Issue	Issuance Date	Shares Issued and Outstanding	Total Book Value	Net Premium and (Expense)	Net Proceeds to Company	Annual Dividend Requirement	Cost of Money to Company	Annualized Cost	Line No.
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**5% Preferred Stock, $100 Par Value**	(a)	126,243	$12,624,300	($98,049)	$12,526,251	$631,215	5.04%	636,156	1
2										2
3	**Serial Preferred, $100 Par Value**									3
4	4.52% Series	Nov-55	2,065	$206,500	($9,676)	$196,824	$9,334	4.74%	9,793	4
5	7.00% Series	(b)	18,046	$1,804,600	(c)	$1,804,600	$126,322	7.00%	126,322	5
6	6.00% Series	(b)	5,930	$593,000	(c)	$593,000	$35,580	6.00%	35,580	6
7	5.00% Series	(b)	41,908	$4,190,800	(c)	$4,190,800	$209,540	5.00%	209,540	7
8	5.40% Series	(b)	65,959	$6,595,900	(c)	$6,595,900	$356,179	5.40%	356,179	8
9	4.72% Series	Aug-63	69,890	$6,989,000	($30,349)	$6,958,651	$329,881	4.74%	331,320	9
10	4.56% Series	Feb-65	84,592	$8,459,200	($49,071)	$8,410,129	$385,740	4.59%	387,990	10
11										11
12	**No Par Serial Preferred, $25 Stated Value**									12
13	Unamortized expense (e)	May-95							67,955	13
14	Unamortized expense (f)	1995							84,019	14
15										15
16	**No Par Serial Preferred, $100 Stated Value**									16
17	$7.48 Series (d)	Jun-92	450,000	45,000,000	(504,260)	$44,495,740	$3,366,000	7.67%	3,452,923	17
18										18
19	**TOTAL**			$86,463,300	($691,405)	$85,771,895	$5,449,790		5,697,775	19
20										20
21										21
22						**Cost of Preferred Stock =**		**6.590%**		22
23										23
24										24
25	(a) Issue replaced 6% and 7% preferred stock of Pacific Power & Light Company and Northwestern Electric Company									25
26	and 5% preferred stock of Mountain States Power Company, most of which sold in the 1920's and 1930's.									26
27	(b) These issues replaced an issue of The California Oregon Power Company as a result of the merger of that Company into Pacific Power & Light Co.									27
28	(c) Original issue expense/premium has been fully amortized or expensed.									28
29	(d) Annual 5% sinking fund begins June 15, 2002.									29
30	(e) Column 10 is the after-tax annual unamortized debt expense related to the 8 3/8% QUIDS redeemed November 2000.									30
31	(f) Column 10 is the after-tax annual unamortized debt expense related to the 8.55% QUIDS redeemed November 2000.									31
32										32

315 Williams Exhibit

Case UE-170
PPL Exhibit 315
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of Bruce N. Williams

Pro Forma Cost of Debt

July 2005

Oregon GRC (UE 170) - exhibit 315

			Outstanding	Annual Debt Service Cost	Cost of Debt	Direct Testimony Exhibit Reference	Sur-Surrebuttal Exhibit Reference
Pro Forma Cost of Debt							
March 31, 2006	**Pro Forma - Direct Testimony**		**4,011,708,119**	**254,803,517**	**6.351%**		
	** Known Changes since Direct Testimony prepared:*						
	(1) 8.625% Series F MTN due 12/13/24	redeemed 12/13/04 [a]	(20,000,000)	(1,787,600)	-8.938%	PPL/301/Williams/3 line 43	Removed
	(2) variable rate PCRBs originally due fy0607	maturities extended 3/16/05	38,125,000	1,466,656	3.847%	Did not exist	PPL/313/Williams/5 lines 25-27
	(3) 5.25% FMB due 6/15/35	new LT debt issued 6/13/05	300,000,000	16,107,000	5.369%	Did not exist	PPL/313/Williams/2 line 7
	Misc true-ups - issuance expense, etc			(2,541)			
	** Update to variable rate PCRB costs to reflect increase in ST rates since Direct Testimony prepared:*						
	variable rate PCRBs - testimony	based on 8/04 forward rates	(503,570,000)	(18,815,465)	-3.736%	PPL/301/5 lines 10-15, 19-24 & 28	
	(6) variable rate PCRBs - updated	based on 6/05 forward rates [b]	503,570,000	22,210,514	4.411%		PPL/313/Williams/5 lines 10-15, 19-24 & 28
	** Update to Pro-forma LT debt issuance rate for remaining pro-forma LT debt to reflect decrease in LT issuance rates since Direct Testimony prepared:*						
	Pro Forma LT debt issuance - testimony	based on 8/04 forward rates	(638,761,000)	(39,654,283)	-6.208%	PPL/301/2 line 7	
	(5) Pro Forma LT debt issuance - updated [c]	based on 6/05 forward rates [d]	324,386,000	18,146,153	5.594%		PPL/313/Williams/2 line 8
March 31, 2006	**Pro Forma - Updated**		**4,015,458,119**	**252,473,952**	**6.288%**		

[a] refinanced originally with ST debt and then with proceeds of new LT debt issued 6/13/05 as noted in offering statement

[b] variable PCRB rate reflects a base 3.36% rate [85% of forward 1mo LIBOR (3.96%)] + issuance & credit enhancement costs.

[c] LT Debt pro-forma issuances in direct testimony based on $400m LT Debt issuances for FY06 + Cur Mat Debt as of 3/31/06.
Pro-forma amount has been adjusted by the following:

638,761,000	Pro-forma LT debt issuance - Direct Testimony
20,000,000	8.625% Series F MTN due 12/13/24 - redemption 12/13/04
(38,125,000)	variable rate PCRBs due fy 0607 - maturities extended 3/16/05
(300,000,000)	New LT debt issuance - 6/13/05
3,750,000	Refinancing of optional preferred stock redemption - 6/15/05
324,386,000	Pro-forma LT debt issuance - Adjusted

[d] new 20yr LT debt issuance as of 3/31/06 @ 5.51% coupon [20yr forward t-rate (4.46%) + 105 bps spread + 9 bps issuance costs].

Oregon GRC (UE 170) - exhibit 315

Pro Forma Cost of Preferred			Outstanding	Annual Debt Service Cost	Cost of Pfd	Direct Testimony Exhibit Reference	Sur-Surrebuttal Exhibit Reference
March 31, 2006	**Pro Forma - Direct Testimony**		**90,213,300**	**5,985,519**	**6.635%**		
	* *Known Changes since Direct Testimony prepared:*						
	(4) $7.48 Pfd Stk - Optional Redemption	optional redemption (6/15/05) [a]	(3,750,000)	(287,744)	-7.673%	PPL/303/1 line 17	PPL/314/1 line 17
March 31, 2006	**Pro Forma - Updated**		**86,463,300**	**5,697,775**	**6.590%**		

[a] as noted in rebuttal testimony, refinancing of optional preferred stock redemption (6/15/05) to be made with additional pro-forma LT debt.

Case UE-170
PPL Exhibit 316
Witness: Bruce N. Williams

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of Bruce N. Williams

Standard & Poor's Summary: PacifiCorp

July 2005

STANDARD & POOR'S | RATINGSDIRECT

Return to Regular Format

Research:
Summary: PacifiCorp

Publication date: 05-May-2005
Primary Credit Analyst(s): Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Credit Rating: A-/Stable/A-2

Rationale

The ratings on PacifiCorp reflect an average business profile, a diversified service territory, a reasonably balanced generation portfolio, and recent favorable regulatory treatment in the six western states it serves. PacifiCorp comprises about 45% of ultimate parent Scottish Power's operating profit. The consolidated Scottish Power financial profile has remained adequate for the rating, despite the fact that the utility's financial profile was until recently strained by significant amounts of deferred power costs.

Since 2002, PacifiCorp has been recovering the sizable power costs it incurred during the western energy crisis in 2000 and 2001. Collection in retail rates of about $303 million of the $537 million that PacifiCorp deferred began in fiscal 2003. But by the end of Dec. 31, 2004, the utility had collected in retail rates all but $26 million in deferred costs, and full recovery is expected to be completed over the next six months.

PacifiCorp faces near-term challenges to its financial performance that are expected to be compensated by the continued strength of Scottish Power consolidated operations. Scottish Power announced last November that collectively PacifiCorp and PacifiCorp Group Holdings Co. (PGHC) would likely fall short of a fiscal 2005 target of $1 billion in earnings before interest and taxes (EBIT, reported on a U.K. GAAP basis), due largely to plant performance and weaker electricity sales at PacifiCorp. (This target excludes the operations of PPM Energy Inc., which is also a subsidiary of PacifiCorp Holdings Inc. [PHI].) The company plans to publish full-year earnings for fiscal 2005 in late May.

Fiscals 2006 and 2007 are forecast to also remain flat on a U.K. GAAP reporting basis. In March, Scottish Power advised that PacifiCorp's first six months of fiscal 2006 performance could be adversely affected by low hydro availability in the Pacific Northwest. About 10% of PacifiCorp's installed capacity is hydro generation, typically supplying between 4% to 8% of the utility's annual generation requirements. Management has estimated that replacement power costs could total about $60 million during calendar 2005. To allow deferred recovery of these expected costs, PacifiCorp recently filed with the Oregon state commission for permission to establish a deferred power account and is expected to do so in Washington.

The absence of a power cost adjustment mechanism in any of the states PacifiCorp serves is an ongoing credit concern because of the uncertainty over the timing and ultimate recovery of potential, new deferred power costs. However, the utility is pursuing adjusters with regulators, and regulatory relationships are stable. In February, the Utah Public Service Commission approved a $51 million rate case settlement, providing a 4% increase that began March 1 and represents a 10.5% return on equity (ROE). In February 2005, the state enacted Senate Bill (SB) 26, which establishes a resource procurement process for PacifiCorp that should substantially increase the utility's prospects for cost recovery. The utility has a pending rate case in Oregon, which is expected to be decided sometime in 2005. Also, four of the six states served by PacifiCorp have approved an agreement for allocating common costs, referred to as the multi-state process, which should streamline recovery of these costs.

Another significant challenge is to effectively manage a $3 billion capital expenditure program. The company is currently building two new gas-fired combined cycle plants. About 280 MW of Currant Creek is expected on line this summer, with 525 MW added by 2006. Lakeside, a 534-MW plant, is expected to be commercial by summer of 2007. Both projects are on time and on budget.

PacifiCorp is headquartered in Portland and serves about 1.6 million retail customers in a 136,000-square-mile service territory in portions of Utah, Oregon, Wyoming, Washington, Idaho, and California. Business is conducted under the legal names of Pacific Power and Utah Power & Light. PacifiCorp is a wholly owned subsidiary of PHI, which in turn is a non-operating, direct, wholly owned subsidiary of U.K. holding company Scottish Power plc.

Short-term ratings factors.

The short-term rating on Scottish Power, Scottish Power U.K. PLC, and PacifiCorp is 'A-2'. In the short term, the companies are expected to have ample internal liquidity, owing to a steady, predictable net cash flow stream produced by regulated businesses, minimal debt maturities over the next few years, good credit facility capacity, and more stable pricing in the western U.S. power markets. Scottish Power's discretionary cash flow after dividends and capital expenditure is expected to be negative in 2004, but its sizable unrestricted cash balance should finance any shortfall. Cash balances, amounting to £424 million at Dec. 31, 2004, are held in a variety of quickly accessible funds.

Scottish Power has sufficient liquidity to cover its outstanding debt obligations and good financial flexibility to access funds in the event of unexpected cash flow interruptions. Full capacity exists under a $1 billion revolving credit facility, split between a $625 million facility and a $375 million facility, both due in 2008. Scottish Power U.K. maintains a $2 billion Euro-commercial paper program, which is undrawn. Liquidity was further enhanced by the issuance of $1.5 billion of long-term debt during March 2005.

PacifiCorp provides for its own liquidity needs. PacifiCorp's cash and cash equivalent position was $25 million as of Dec. 31, 2004, down from $59 million as of March 31, 2004. Liquidity is enhanced by the utility's $800 million commercial paper program. As of Dec. 31, 2004, the company had drawn $285 million in commercial paper. An $800 million revolver executed in May 2004 backstops the commercial paper program. There were no borrowings under the facility as of Dec. 31, 2004. Regulatory authorities limit PacifiCorp from issuing more than $1.5 billion in short-term debt.

PacifiCorp's discretionary cash flow after dividends and capital expenditure is expected to be negative in fiscal 2005. PacifiCorp's long-term debt outstanding was $3.7 billion as of Dec. 31, 2004, excluding current maturities. Future maturities of $289 million in fiscal 2006 are in line with historic obligations. Affiliate transaction rules restrict PacifiCorp from lending to any of PHI's subsidiaries or U.K. affiliates.

Outlook

The stable outlook reflects consolidated Scottish Power's financial ratios that are adequate for the rating and the steady operational and financial performance at the company's regulated subsidiaries. To maintain the rating, Standard & Poor's expects Scottish Power to produce cash flow coverage ratios commensurate with the 'A-' level--adjusted FFO interest coverage of about 4.0x and adjusted FFO to debt of 20%--and to manage its U.K. generation and supply and U.S. unregulated energy management business conservatively. An improvement in the ratings is less likely, given the sizable capital expenditures for both the U.K. and U.S. operations, and management's expectations that PacifiCorp's financial performance over the next few years will remain flat.

Accounting

PacifiCorp is one of four subsidiaries of PacifiCorp Holdings Inc. (PHI), which is an indirect subsidiary of Scottish Power plc. Other companies under PHI are unregulated and consist of PPM Energy Inc. (PPM); Pacific Klamath Energy Inc. (PKE); and PacifiCorp Group Holdings Co. (PGHC), a holding company for non-regulated companies, including PacifiCorp Financial Services Inc. (PFS).

PacifiCorp's financial statements are prepared under U.S. GAAP standards and are audited by PriceWaterhouseCoopers LLC, which provided an unqualified opinion for fiscal 2004, which ended March 31, 2004. PacifiCorp's financial statements are also reported as part of its parent, Scottish Power, whose audits are prepared under U.K. GAAP by PWC. PacifiCorp is the only subsidiary under PHI that has issued public debt in the U.S., and as such is the only PHI company that is required to file before the Securities and Exchange Commission (SEC). Scottish Power's financial segment reporting combines the results of operations for both PacifiCorp and PGHC, whereas U.S. filings reflect the stand-alone results of the utility.

Comparison of PacifiCorp's financial results as filed with the SEC to those reported by Scottish Power's requires making a number of adjustments to reconcile differences between U.S. and U.K. GAAP accounting as well as the inclusion of PGHC. The largest difference is attributable to the differing treatment of PacifiCorp's recovery of sizable power costs incurred several years ago. Under U.K. GAAP, PacifiCorp's replacement power obligations were expensed in full when incurred on Scottish Power's income statement. But under U.S. GAAP FAS 71 allowed the utility to create a regulatory asset on the utility's balance sheet. As PacifiCorp has collected these deferred costs in rates, its income statement has reflected the amortization of deferred power costs as an expense under U.S. GAAP, providing a smoothing effect for PacifiCorp net income. In contrast, as the recovery of deferred costs flows directly into revenues, with no offsetting amortization expense, U.K. GAAP earnings have been boosted over the period of recovery. In fiscal 2004, for example, U.S. GAAP EBIT for PacifiCorp and PGHC was $685 million, but on a U.K. GAAP basis, EBIT was $945 million. Power cost deferrals accounted for $110 million of this difference. With the pending completion of recovery in fiscal 2006, the wedge between U.K. and U.S. GAAP will narrow, but other recurring adjustments to depreciation and other accounts will remain. And, beginning in April 2006, Scottish Power will adopt International Accounting Standards. PGHC is involved in the receipt of revenues under synthetic fuels contract and the leasing of commercial aircraft.

PacifiCorp has sizable power purchase obligations, and as a result, Standard & Poor's Ratings Services has added about $570 million to the utility's balance sheet that predominantly reflects long-term power purchase agreements (PPAs) and about $46 million in operating leases. Standard & Poor's uses a 50% risk factor in calculating off-balance sheet debt associated with these PPAs. The passage of SB 26 implies that a lower risk factor will be utilized for future Utah PPAs that fall under the protection of the new legislation.

Case UE-170
PPL Exhibit 418
Witness: David L. Taylor

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-Surrebuttal Testimony of David L. Taylor

Cost of Service

July 2005

Q. Are you the same David L. Taylor that presented direct and rebuttal testimony in this case?

A. Yes I am.

Purpose of Testimony

Q. What is the purpose of your sur-surrebuttal testimony?

A. My sur-surrebuttal testimony covers three areas. First, I include a restatement of one of my exhibits to reflect the interim treatment of the Klamath Irrigation customers referenced in the Prehearing Conference Memorandum dated June 30, 2005, as well as other changes in the Oregon Results of Operations as discussed by Mr. Wrigley.

Second, in response to ICNU witness Mr. Falkenberg's surrebuttal testimony, I reiterate the Company's position that the four recently executed QF contracts are appropriately treated as "New QF Contracts" under the Revised Protocol allocation.

Third, I respond to the surrebuttal testimony of ICNU witness Ms. Iverson.

Updated Exhibits

Q. Have you prepared any updates to your exhibits filed in your direct case?

A. Yes. PPL Exhibit 419 is a restatement of PPL Exhibits 409 and 417. This update reflects two changes from those filed in our rebuttal case. First, it reflects the treatment of the Schedule 33 present revenues as agreed by the parties and referenced in the Prehearing Conference Memorandum dated June 30, 2005. Second, it reflects other adjustments to the Oregon Results of Operations as described in the sur-surrebuttal testimony of Mr. Wrigley. Third, because the status of the Klamath River On-Project and Off-Project irrigation customers will not be decided during this phase of the case, these customers have been removed from Schedule 41 in both the marginal cost study and in the allocation of the proposed rate increase.

New QF Contracts

Q. After reviewing the surrebuttal testimony of Mr. Falkenberg do you continue to support the treatment of the US Magnesium, Desert Power, Kennecott, and Tesoro, QF contracts as "New QF Contracts" under the Revised Protocol allocation?

A. Yes I do. The four contracts in question were appropriately treated as New QF Contracts in accordance with the stated provisions of the Revised Protocol. Mr. Falkenberg's assertion is wrong and should be dismissed. Section II of the Revised Protocol clearly states that "The Protocol will be effective and apply to all PacifiCorp retail general rate proceedings initiated subsequent to June 1, 2004." We understood that the parties to this case agreed that the general rate case, filed in November 2004, would be based on the Revised Protocol, with the understanding that its new methodology was effective June 1, 2004. The treatment of new QFs was an integral part of the Revised Protocol, and the treatment of these contracts should be consistent with the methodology on which this general rate case was filed.

Q. Does Staff support the treatment of these QF contracts as New QF Contracts under the Revised Protocol?

A. Yes. This effective date is recognized by the Commission staff and is supported in the surrebuttal testimony of staff witness Mr. Wordley where he states "Even though the order was not signed until January 2005, because the Commission did not change the Section II language, the effective date of the Revised Protocol is June 1, 2004." These contracts were entered into subsequent to that date and are appropriately identified as New QF Contracts.

Q. Mr. Falkenberg states that the new US Magnesium QF contract is reflected differently in this case than it was in the recently completed Utah case. Is he correct?

A. No. Both the Utah rebuttal case and the current state of the Oregon case reflect the pricing and terms of the new US Magnesium QF contract. As the pricing terms of the contract became final both cases were updated to reflect those terms. The terms of new US Magnesium QF contract were included in the March Net Power Cost update to the Oregon case.

Demand and Energy Classification of Marginal Costs

Q. In her surrebuttal testimony, ICNU witness Ms. Iverson claims that "Under (her) reconciliation proposal, there is no shift between the demand and energy components of customer prices." Do you agree?

A. No. She uses as support for her claim that the energy only pricing structure for Schedule 200 and the demand only structure for transmission charges will not change. While it is true that the demand and energy structure of those rate schedules would not change as a result of her proposal, the price levels within those structures would change. Her reconciliation proposal would decrease the allocation of the underlying generation and transmission costs to higher load factor customers and increase the allocation of those costs to lower load factor customers.

Q. Does this conclude your sur-surrebuttal testimony?

A. Yes it does.

419 Taylor Exhibit

Case UE-170
PPL Exhibit 419
Witness: David L. Taylor

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of David L. Taylor

December 31, 2006 Unbundled Revenue Requirement Allocation by Rate Schedule

July 2005

PacifiCorp
State of Oregon
December 31, 2006 Unbundled Revenue Requirement Allocation by Rate Schedule

			(A)	(B)	(D)	(E)	(I)	(J)	(M)	(N)	(O)	(R)	(S)	(T)	(U)
			Residential	**General Service Sch 23**		**General Service Sch 28**		**General Service Sch 30**		**Large Power Service Schedule 48T**			**Sch 41** Irrigation		**Street** Lighting
Line	Description	Total	(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(pri)	(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	$0	$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	0	25,509
3															
4	**Functionalized 20 Year Full Marginal Costs - Class $**														
5	Generation	$551,833	$216,355	$48,419	$31	$87,279	$899	$56,287	$3,731	$37,174	$73,138	$22,688	$5,068	$0	$763
6	Transmission	$54,546	$21,706	$4,952	$3	$8,618	$88	$5,576	$369	$3,626	$6,961	$2,090	$508	$0	$49
7	Distribution	$285,855	$180,358	$40,437	$15	$27,470	$218	$13,395	$840	$6,759	$6,276	$0	$7,020	$0	$3,067
8	Customer - Billing	$12,410	$10,046	$1,411	$1	$498	$3	$49	$3	$110	$72	$1	$197	$0	$19
9	Customer - Metering	$15,344	$11,439	$2,203	$33	$877	$62	$203	$64	$38	$105	$23	$294	$0	$1
10	Customer - Other	$8,679	$7,203	$942	$0	$283	$2	$53	$3	$54	$35	$0	$96	$0	$9
11	Total	$928,667	$447,107	$98,365	$84	$125,025	$1,272	$75,562	$5,011	$47,761	$86,586	$24,803	$13,182	$0	$3,909
12															
13	**Functional Revenue Requirement Allocation Factors**														
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**														
15	Generation	100.00%	39.21%	8.77%	0.01%	15.82%	0.16%	10.20%	0.68%	6.74%	13.25%	4.11%	0.92%	0.00%	0.14%
16	Transmission	100.00%	39.79%	9.08%	0.01%	15.80%	0.16%	10.22%	0.68%	6.65%	12.76%	3.83%	0.93%	0.00%	0.09%
17	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%	0.00%	1.07%
18	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%	0.00%	0.14%
19	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%	0.00%	0.16%
20	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%	0.00%	0.01%
21	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%	0.00%	0.11%
22	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%	0.00%	0.19%
23	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%	0.00%	0.44%
24	Taxes (Revenue)														
25															
26	**Functionalized Class Revenue Requirement - (Target)**														
27	Generation	$491,531	$192,712	$43,128	$28	$77,742	$801	$50,136	$3,324	$33,112	$65,146	$20,209	$4,514	$0	$680
28	Transmission	$64,597	$25,706	$5,864	$4	$10,206	$104	$6,603	$437	$4,294	$8,243	$2,476	$601	$0	$58
29	Distribution	$225,910	$142,536	$31,958	$12	$21,709	$172	$10,586	$664	$5,341	$4,960	$0	$5,548	$0	$2,424
30	Ancillary Services	$10,477	$4,108	$919	$1	$1,657	$17	$1,069	$71	$706	$1,389	$431	$96	$0	$14
31	Customer - Billing	$22,764	$18,428	$2,588	$1	$914	$5	$90	$5	$202	$131	$1	$362	$0	$36
32	Customer - Metering	$23,304	$17,373	$3,346	$50	$1,332	$94	$308	$98	$58	$160	$35	$446	$0	$2
33	Customer - Other	$9,420	$7,818	$1,022	$0	$307	$2	$57	$3	$58	$38	$0	$104	$0	$10
34	Embedded DSM - (mWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Regulatory & Franchise T	$18,889	$9,281	$1,772	$1	$2,776	$28	$1,575	$105	$922	$1,639	$460	$247	$0	$83
36	Total	$866,892	$417,963	$90,598	$97	$116,644	$1,224	$70,424	$4,707	$44,693	$81,706	$23,612	$11,918	$0	$3,307
37															
38	**Ratio of Operating Revenue to Reven**	91.40%	93.14%	82.03%	49.83%	99.82%	95.61%	93.81%	93.50%	86.52%	84.16%	81.77%	86.85%	#DIV/0!	105.43%
39	(Line 1 / Line 36)														
40															
41	**Increase or (Decrease)**	$74,560	$28,651	$16,278	$49	$208	$54	$4,357	$306	$6,025	$12,941	$4,304	$1,567	$0	($179)
42	(Line 36 - Line 1)														
43															
44															
45	**Percent Increase (Decrease)**	9.41%	7.36%	21.90%	100.67%	0.18%	4.59%	6.60%	6.95%	15.58%	18.82%	22.29%	15.14%	#DIV/0!	-5.15%
46	(Line 41 / Line 1)														

Func Rev Req - earned

PacifiCorp
Oregon Marginal Cost Study
December 31, 2006 Functionalized Revenue - Earned
($ 000)

		A	B	C	D	E	F	G	H	I	J
Line No.	Description	Generation	Transmission	Distribution	Ancillary	C Billing	C Metering	C Other	DSM	Franchise Fees	Total
1	Earned Functional Revenue Requirement	$475,037	$52,649	$204,301	$10,772	$22,667	$22,804	$9,398	$0	17,729	$815,356
2											
3	Percent of Total	58.26%	6.46%	25.06%	1.32%	2.78%	2.80%	1.15%	0.00%	2.17%	100.00%
4											
5	Revenue From Classes Included in MC Study	$461,622	$51,163	$198,532	$10,468	$22,026	$22,160	$9,132	$0	$17,229	$792,332
6											
7	Other Revenues										
8	Partial Requirements - Sch. 36 pri (to 23 pri)										$0
9	Partial Requirements - Sch. 36 pri (to 28 pri)										$58
10	Partial Requirements - Sch. 36 pri (to 30 pri)										$294
11	Partial Requirements - Sch. 47 pri										$7,238
12	Partial Requirements - Sch. 47 trn										$3,650
13	USBR Billed Revenue										$604
14	USBR Imputed Revenue										$7,105
15	AGA										$1,404
16	Lighting										$3,067
17	Employee Discount										($397)
18	Total Oregon Situs Revenue										$815,356
19											
20	Special Contracts										$0
21	Removal of USBR Imputed Revenue										($7,105)
22	Total Oregon Revenue										$808,251

Func Rev Req - target

PacifiCorp
Oregon Marginal Cost Study
December 31, 2006 Functionalized Revenue - Target
($ 000)

		A	B	C	D	E	F	G	H	I	J	
Line No.	Description	Generation	Transmission	Distribution	Ancillary	C Billing	C Metering	C Other	DSM	Franchise Fees	Total	
1	Target Functional Revenue Requirement	505,365	66,415	232,268	10,772	23,405	23,960	9,686	0	19,420	$891,291	
2												
3	Percent of Total	56.70%	7.45%	26.06%	1.21%	2.63%	2.69%	1.09%	0.00%	2.18%	100.00%	
4												Increase
5	Revenue From Classes Included in MC Study	$491,531	$64,597	$225,910	$10,477	$22,764	$23,304	$9,420	$0	$18,889	$ 866,892	$74,560
6												
7	Other Revenues											75,935
8	Partial Requirements - Sch. 36 pri (to 23 pri)										$1	$0
9	Partial Requirements - Sch. 36 pri (to 28 pri)										$51	-$7
10	Partial Requirements - Sch. 36 pri (to 30 pri)										$257	-$36
11	Partial Requirements - Sch. 47 pri										$8,147	$908
12	Partial Requirements - Sch. 47 trn										$4,347	$697
13	USBR Billed Revenue										$604	$0
14	USBR Imputed Revenue										$7,105	$0
15	AGA										$1,404	$0
16	Lighting										$2,909	-$158
17	Employee Discount										($426)	($29)
18	Total Oregon Situs Revenue										$891,291	74,560
19												
20	Special Contracts										$0	
21	Removal of USBR Imputed Revenue										($7,105)	
22	Total Oregon Revenue										$884,186	

PacifiCorp
State of Oregon
December 31, 2006 Unbundled Revenue Requirement Allocation
Distribution - Substations & Facilities Breakout

		(A)	(B)	(C)
			Large Power Service Schedule 48T	
Line	Description	(sec)	(pri)	(trn)
1	**Total Operating Revenues**	$38,668	$68,765	$19,309
2	**MWH**	901,394	1,872,828	614,130
3				
4	**Functionalized 20 Year Full Marginal Costs - Class $**			
5	Generation	$37,174	$73,138	$22,688
6	Transmission	$3,626	$6,961	$2,090
7	Distribution	$4,556	$2,467	$0
8	Distribution - substations	$2,202	$3,809	$0
9	Customer - Billing	$110	$72	$1
10	Customer - Metering	$38	$105	$23
11	Customer - Other	$54	$35	$0
12	Total	$47,761	$86,586	$24,803
13				
14	**Functional Revenue Requirement Allocation Factors**			
15	**Functionalized 20 Year Full Marginal Costs - Class % of Total**			
16	Generation	6.74%	13.25%	4.11%
17	Transmission	6.65%	12.76%	3.83%
18	Distribution	1.81%	0.98%	0.00%
19	Distribution - substations	6.54%	11.30%	0.00%
20	Ancillary Service	6.74%	13.25%	4.11%
21	Customer - Billing	0.89%	0.58%	0.01%
22	Customer - Metering	0.25%	0.69%	0.15%
23	Customer - Other	0.62%	0.40%	0.00%
24	Embedded DSM - (mWh)	6.79%	14.12%	4.63%
25	Regulatory & Franchise	4.88%	8.68%	2.44%
26	Taxes (Revenue)			
27				
28	**Functionalized Class Revenue Requirement - (Target)**			
29	Generation	$33,112	$65,146	$20,209
30	Transmission	$4,294	$8,243	$2,476
31	Distribution	$3,601	$1,950	$0
32	Distribution - substations	$1,740	$3,010	$0
33	Ancillary Services	$706	$1,389	$431
34	Customer - Billing	$202	$131	$1
35	Customer - Metering	$58	$160	$35
36	Customer - Other	$58	$38	$0
37	Embedded DSM - (mWh)	$0	$0	$0
38	Regulatory & Franchise T	$922	$1,639	$460
39	Total	$44,693	$81,706	$23,612
40				
41	**Ratio of Operating Revenue to Reven**	86.52%	84.16%	81.77%
42	(Line 1 / Line 39)			
43				
44	**Increase or (Decrease)**	$6,025	$12,941	$4,304
45	(Line 39 - Line 1)			
46				
47	**Percent Increase (Decrease)**	15.58%	18.82%	22.29%
48	(Line 44 / Line 1)			

611 Widmer Testimony

Case UE-170
PPL Exhibit 611
Witness: Mark T. Widmer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-Surrebuttal Testimony of Mark T. Widmer

Power Costs/RVM

July 2005

Q. Are you the same Mark T. Widmer that filed direct testimony with the Company's original filing?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will rebut Industrial Customers of Northwest Utilities (ICNU) Randy Falkenberg's UM 995 Deferral Period outage adjustment, RVM testimony on outage update period, maintenance schedule, thermal ramping, deferred maintenance and station service.

<u>UM 995 Deferral Period Outage Adjustment</u>

Q. Mr. Falkenberg continues to suggest there is a double count of outages because the Company's modeling is intended to provide a four year amortization of the costs being recovered in the UM 995 deferral. Is that the case?

A. No. Mr. Falkenberg's suggestion is incorrect. The amount collected in the UM 995 deferral was calculated as the difference between actual net power costs including actual outages and net power costs and outages in rates. Because the level of other outages in rates is consistent with the actual level of other outages that occurred during the deferral period, there is no double count. Put another way, because the level of other outages during the UM 995 deferral period was similar to the level of other outages in rates, the difference between the two is zero and there is no double count. Mr. Falkenberg's proposed adjustment incorrectly assumes that the difference between x and x is a very large number and that is simply not the case.

Q. Was the cost of the UM 995 other outages higher than the level in rates even though the level of other outages included in rates was similar?

A. Yes. However, the increased cost was attributable to the exorbitant market prices prevalent during the deferral period, not the level of outages. Since the Company is only requesting recovery of the outages based on normal market prices, not the exorbitant market prices of the deferral period, there is not a double count from a cost perspective either.

Q. Do you agree with Mr. Falkenberg's suggestion that your testimony on the removal of other outages is misleading and that the removal of other outages was calculated differently from the Hunter outage calculation?

A. No. The Company removed the entire Hunter outage by removing the 5 months of outage information on Hunter. This included the outage and the scheduled operation (forced outage hours + in service hours). In the end, the outage level calculated for Hunter 1 in this case was based on approximately 43 months of outages and 43 months of scheduled operation. Consistent with the Hunter outage calculation, the Company eliminated the impact of other outages by removing the outages and the scheduled hours. In the end, once the UM 995 deferral period outages have been removed, the outage rate is based on approximately 38 months of outages and 38 months scheduled operation. So, the methodology employed by the Company for the Hunter 1 outage and other outages is consistent because we match forced outage months with scheduled operation. On the other hand, Mr. Falkenberg's proposed treatment is not consistent, is misleading and would not result in a normal level of ongoing outages in rates.

Q. Please explain.

A. Forced outage rates are developed monthly by dividing the hours of forced outages by scheduled hours. Mr. Falkenberg inappropriately mismatches forced outage hours and scheduled hours for other outages by removing the other forced outages but not removing all scheduled hours for each month of the deferral period. In fact, all he removes are the forced outage hours from the numerator and the denominator of the forced outage rate calculation. He does not remove the remaining in-service hours from those same months. In the end, Mr. Falkenberg's outage rate calculation is mismatched because it is based on roughly 38 months of forced outages and something slightly less than 48 months and significantly more than 38 months for scheduled hours. This mismatch produces an unreasonably low forced outage rate for the test period. For this reason and the reasons explained above, the proposed adjustment should be rejected.

Q. Did Staff address Mr. Falkenberg's proposed adjustment for UM 995 period outages in their rebuttal testimony?

A. Yes. Staff witness Mr. Wordley also concluded that there is no double recovery for UM 995 outages and recommended that the Commission reject Mr. Falkenberg's proposed adjustment. Staff/800/Wordley/10.

RVM Issues

Q. Do you agree with Mr. Falkenberg that the value the Company has calculated for the transition adjustment is the value of the freed-up resources to the Company?

A. Yes. As long as the Company pays direct access customers the value of the freed-up energy, customers who remain on the Company's system will not subsidize direct access customers. However, if the Company pays direct access customers more than the value to the Company of the freed-up resources, customers that remain on the system will be inappropriately subsidizing direct access customers.

Q. Mr. Falkenberg criticizes aspects of the GRID model, including market cap modeling and GRID's use in calculation of the transition adjustment. Is there any merit in his issues?

A. No. First, the GRID model is used to set net power costs for retail rates and therefore, should be used to calculate the net power cost impact of direct access. Second, as explained by Staff witness Mr. Galbraith, the Partial Stipulation represents a complete and final resolution of the market cap issue for direct access. Third, Mr. Falkenberg's surrebuttal testimony merely suggests there may be problems. He provides no evidence that a problem exists, so there is no basis to support his conclusion and his rejection of the GRID model. Further, it is worth noting that in Mr. Falkenberg's direct testimony he did not raise any issues regarding market cap modeling, and shaping of wholesale market prices.

Q. Is it surprising that the calculation of the transition credit by GRID produces a price that is a little lower than the market price of power?

A. No. It is important to remember that the Company has planned to have potential direct access customers on its system and has optimized its system based on those expectations. That optimization includes buying energy to cover short positions and selling excess capacity into the market. This is usually accomplished through short-term firm (STF) transactions. During graveyard hours the wholesale market is limited because utilities generally acquire or build resources to meet peak requirement and are surplus at that time. So it is predictable that when resources are freed-up, a small portion can not be sold into the wholesale market due to illiquidity and limited amounts of thermal generation must be backed down slightly to balance the system.

Q. Mr. Falkenberg suggests his transmission adder adjustment is conservative and justified because as load grows, additional transmission will be required which will be more costly than existing contracts. Is this argument relevant for this case?

A. No. Mr. Falkenberg has completely overlooked the fact that at this time PacifiCorp's long-term transmission contracts with BPA are fixed and the costs are not avoidable. The only transmission benefits that are potentially avoidable are day-ahead firm or non-firm transmission that would be derived from the redispatch of the Company's system. These benefits are automatically included in the GRID redispatch of the Company's system for direct access. Therefore, a transmission adder is not justified at this time.

Q. Were Mr. Falkenberg's proposed RVM adjustments addressed in the Third Partial stipulation between the Company and Staff?

A. Yes. As part of the Third Partial Stipulation, the Company and Staff agreed to remove RVM adjustments for thermal ramping, station service, deferred maintenance outages, and actual planned maintenance, if the RVM is adopted by the Commission. These same adjustments were proposed by Mr. Falkenberg. The Company and Staff also agreed that the outage period update adjustment should be incorporated into RVM net power costs. Mr. Falkenberg does not support the Company's outage period update adjustment.

Q. Did Mr. Falkenberg's surrebuttal testimony present any new evidence which would justify his proposal to exclude the outage period update?

A. No. The fact remains that the Company provided the information which supported the adjustment on a timely basis to ICNU and Mr. Falkenberg was not disadvantaged by the procedural process. Further, the outage period update contributes to the accuracy of the Company's RVM net power costs by basing them on the most current information possible. This view is also held by Staff. Staff witness Mr. Wordley testifies that:

> One of the objectives of the RVM is to get power costs as accurate as possible for the calendar year that the resulting rates will be in effect. (Staff/800, Wordley/9).

Q. In the event RVM is not adopted by the Commission should the Company's RVM update adjustments be incorporated into the general rate case net power costs?

A. Yes. It is as important during a general rate case to include the most current information that is available as it is for an RVM proceeding. If new contracts are entered or terminated, errors are discovered or other information pertinent to the test period becomes available during the case, that information should be incorporated into rates.

Q. Should all of the RVM adjustments be incorporated into the general rate case if RVM is not adopted?

A. No. The planned outages and the outage period update adjustments are specific to the RVM process and should not be included in the general rate case.

Q. What is the impact of including the RVM adjustments, excluding the two mentioned above, if they were rolled into general rate case net power costs?

A. The RVM adjustments would increase net power costs by approximately $4.9 million on an Oregon basis if adopted. This is slightly higher than the $4.3 million level stipulated to by the Company and Staff. Of course, in addition to the outage period update adjustment proposed by Mr. Falkenberg, which I discussed above, he also contested the Thermal Ramping, Station Service and Deferrable Maintenance adjustments. My following testimony addresses Mr. Falkenberg's testimony on those adjustments in the event RVM is not adopted by the Commission.

<u>Thermal Ramping/Station Service</u>

Q. Mr. Falkenberg suggests that a historical backcast previously performed by the Company supports his contention that GRID understates coal generation. Do you agree?

A. No. The backcast for the twelve month period ending September 2002 was performed with an older version of GRID than is being used in this case. Its results are therefore inapplicable to this case.

Q. Is it your opinion that no matter how high loads become, coal fired generation will remain constant as Mr. Falkenberg suggests?

A. No. Coal fired generation will dispatch based on its cost compared to market prices, market liquidity and system constraints. Coal generation is usually dispatched at or near maximum during on-peak and some of the off-peak hours, with the exception of generation that is withheld for reserves and load following due to the low cost. As such, increases in load are not likely to result in significantly higher coal generation.

Q. Does Mr. Falkenberg's study provide a valid example of coal fired generation increasing due to increased loads?

A. No. As I explained in my rebuttal testimony, Mr. Falkenberg's study should not be used because it is flawed and incomplete. The incompleteness and design of his analysis forces the GRID model to back down thermal generation to unrealistically low levels.

Q. Do you agree with Mr. Falkenberg's suggestion that the UE-139 Commission decision that rejected PGE's ramping adjustment is on point relative to the Company's thermal ramping adjustment?

A. No. The circumstances are completely different and therefore the PGE order does not provide a sound basis disallowing the Company's adjustment. PGE merely speculated that the problem was related to ramping. In the Company's case, there is no speculation that the Company's thermal generation is reduced as a result of ramping after outages, it is a fact.

<u>Deferrable Maintenance Adjustment</u>

Q. Regarding the Company's deferrable maintenance adjustment, Mr. Falkenberg claims that the Company ignores the fact that these outages are deferrable and that they should always be completed during the weekend. Do you have any comments?

A. Yes. Mr. Falkenberg's assertion is wrong. While the outages are deferrable, it does not always mean that they are deferred until weekends. The deferral decisions are made by the plant operators based on what is happening on the system as to when the maintenance should be performed. For example, a decision may be made to perform the maintenance during on-peak hours because a unit has a forced outage. Just because the maintenance is deferrable does not mean it is going to be performed on weekends and the data supports this conclusion.

Q. Please explain.

A. As presented in my rebuttal testimony, plant records show that 51 percent of deferrable maintenance occurs during on-peak hours Monday-Saturday. In Mr. Falkenberg's surrebuttal he correctly pointed out that my data included Saturdays so it was not a valid comparison because we are trying to ascertain how much of the deferrable maintenance occurs on weekends versus the rest of the week. Since then my analysis has been updated to only look at on-peak hours Monday-Friday so that weekends would be excluded. That analysis shows that 42 percent of deferrable maintenance occurred Monday-Friday during on-peak hours. This demonstrates that Mr. Falkenberg's assertion that all deferrable maintenance occurs only on weekends is false and should be rejected because the modeling should be as representative of actual operations as possible.

Q. Mr. Falkenberg suggests that it is unsound for PacifiCorp to be allowed to reflect actual scheduled outages for the rate effective period under RVM. Do you have any comments?

A. Yes. Mr. Falkenberg suggests that it is critical to determining PGE's power costs to include expected actual outages because they have only one coal plant and thus may be better able to predict power costs. While the Company has many more coal plants than PGE, allowing the Company to include scheduled actual maintenance would also allow the Company to better predict net power costs for the RVM rate effective period. It is worth noting that the single largest RVM adjustment proposed by the Company was for scheduled outages. If the underlying goal of the RVM process is to produce results that are as representative as possible for the rate effective period, that goal should apply equally to PGE and the Company.

Q. Does this complete your sur-surrebuttal testimony?

A. Yes.

Case UE-170
PPL Exhibit 702
Witness: Christy A. Omohundro

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-Surrebuttal Testimony of Christy A. Omohundro

RVM

July 2005

Q. Please state your name.

A. My name is Christy A. Omohundro.

Q. Did you previously offer testimony in this proceeding?

A. Yes, I filed direct and rebuttal testimony in this proceeding.

Purpose and Summary of Testimony

Q. What is the purpose of your sur-surrebuttal testimony?

A. The purpose of my sur-surrebuttal testimony is to address the arguments raised by Citizens Utility Board (CUB) witness Mr. Jenks and Industrial Customers of the Northwest (ICNU) witness Mr. Falkenberg against the proposed structure and schedule of the PacifiCorp's Transition Adjustment Mechanism (RVM). I will also comment on Staff witness Mr. Galbraith's recommendation to make adjustments to the Company's annual net power cost updates.

Q. Please summarize your testimony.

A. The Company believes that its proposed RVM accurately reflects the impact on PacifiCorp's system of customers choosing direct access. The RVM also helps accomplish the basic regulatory principle that customer rates, to the extent possible, should reflect current costs. The Company has accepted Mr. Galbraith's recommendation to include the lower variable costs of all new resources in the annual net power cost update, independent of a general filing which would update the higher fixed costs. This concession will give customers the benefit of lower variable costs until the fixed cost portion of the new resources can be included in rates. The proposed RVM with the annual net power cost update provides a fair and workable transition adjustment to departing customers, and better aligns customer rates with the Company's actual costs.

Q. Does Staff support PacifiCorp's proposed RVM?

A. Yes, with one new exception. In his surrebuttal testimony, Staff witness Mr. Galbraith states that "PacifiCorp's proposed Transition Adjustment provides an accurate accounting of the likely impacts of direct access on PacifiCorp's system operations and can be expected to result in transition adjustment rates that reasonably balance the interests of retail electricity consumers and utility investors." Mr. Galbraith modifies PacifiCorp's proposal by recommending that the Company include the variable costs of all improvements to existing resources and all new resources that are in-service prior to the beginning of the rate effective period in the Company's annual net power cost update.

Q. What is the Company's response to Mr. Galbraith's recommendations?

A. As stated in my rebuttal testimony, the Company designed its RVM to exclude variable costs associated with new resources until the plant is providing utility service, as contemplated under ORS 757.355, and the matching fixed costs have been included in the Company's rate base. However, if the Commission would prefer to have the variable costs associated with new resources incorporated into the Company's annual net power cost update, the Company is willing to make this change to the RVM mechanism proposed in this case, assuming the Company is able to bring fixed costs associated with new resources into rates on an expeditious basis.

Q. Does the Company's willingness to adopt Mr. Galbraith's recommendation to include variable costs associated with new resources in the RVM update address CUB's "phantom costs" argument?

A. Yes, subject to the limitations of Oregon's used and useful statute. Incorporating variable costs associated with new resources will ensure customers' rates are based on all used and useful plant, and will eliminate reliance on the proxy market purchases, to which CUB was strongly opposed.

Q. Mr. Galbraith suggests that an annual update of the NVPC component of cost-of-service rates shifts power cost risk from shareholders to ratepayers. Staff/700/Galbraith/11. Is this the primary purpose of the Company's proposal?

A. No. The Company proposed its RVM for purposes of facilitating direct access participation, in response to stakeholder comments and the Commission Order in UM 1081. Furthermore, the Company does not agree that an annual update of NVPC shifts risk from shareholders to customers. While it is true that an annual update of net power costs reduces regulatory lag by allowing the Company to update costs outside of general rate case decisions, this reduction of lag goes both ways, and will benefit customers in periods of lower net power costs. If, for example, the forward price curve were to demonstrate a downward trend in future natural gas prices, then customers would benefit from the Company's annual net power cost updates as prices would be reduced to coincide with up-to-date costs.

Q. Please summarize the arguments made by Mr. Jenks and Mr. Falkenberg against the structure and schedule of the Company's proposed RVM.

A. Mr. Jenks continues to argue that PacifiCorp's proposed RVM should not apply to residential customers and repeats his concern that the proposed RVM makes it difficult to conduct prudence reviews, creates a mismatch between fixed costs and variable costs and allocation factors, enables the utility to "game the regulatory system," shifts additional risk of Utah load growth onto Oregon customers, and increases regulatory burden on all customer classes.

Mr. Falkenberg disputes the Company's statement that the proposed mechanism is largely mechanical and repeats his contention that an annual RVM creates increased regulatory burden on intervenors and the Staff and is not necessary.

Q. CUB's primary argument against PacifiCorp's proposed RVM is its inclusion of residential customers. Please address this issue.

A. As stated in my rebuttal testimony, updating power costs for only a subset of PacifiCorp's customer base would be complex and difficult to achieve in the timeframe required for the direct access enrollment process. Mr. Jenks' assertion that "simply applying the proposed mechanism only to those customers who are eligible for direct access can be easily done" demonstrates a lack of appreciation of the complexity of PacifiCorp's rate setting process. CUB/200/Jenks/25.

Staff witness Mr. Galbraith confirmed PacifiCorp's concern that an update for only some customers would be complex and states that Mr. Jenks' proposal would "be difficult to implement and would result in two sets of cost-of-service rates, one for direct access eligible customers, and one for non-direct access eligible customers". Staff/700/Galbraith/17. He then concludes that "once stakeholders and the Commission have gone to the trouble of reviewing the prudence and reasonableness of the company's projected NVPC it makes sense to update the cost-of-service rates for all customers, not just those eligible for direct access". Staff/700/Galbraith/17.

Mr. Galbraith also comments that by simultaneously setting PacifiCorp's cost-of-service energy rates and transition adjustment rates, the Commission can shield both PacifiCorp's cost-of-service customers and PacifiCorp's shareholders from unwarranted cost shifts. Staff/700/Galbraith/16. He points out that PacifiCorp's cost-of-service energy rates should be based on projected NVPC given the assumption of no direct access, and that the transition adjustment rates should be set based on the impact of direct access on PacifiCorp's costs and revenues. This combined ratemaking does not provide incentive to direct access eligible customers on their choice to go direct access or remain with the company. Staff/700/Galbraith/16.

Q. Please address CUB's concern that no process exists for customers to review and verify the costs included in the Company's October update or the Forward Price Curve used to set the transition adjustment.

A. Updating the Company's official forward price curve and net power costs to include new market purchase contracts, fuel purchases, and energy transactions in October – just before the direct access transition adjustment is calculated – ensures the adjustment applied to departing customers is as accurate as possible and is in the best interest of all customers. If CUB has concerns with specific updates included in the Company's annual update, Staff witness Mr. Galbraith suggests that procedural avenues are available to the parties in the event they feel they cannot adequately address specific updates. Staff/700/Galbraith/12. Mr. Galbraith also states that PGE's annual RVM process has demonstrated that a complete review of all power cost issues can be accomplished. Staff/700/Galbraith/13.

With respect to the Company's Forward Price Curve, Mr. Galbraith comments that CUB did not challenge the use of PacifiCorp-produced forward price curves in the revenue requirement portion of the case and does not feel that this issue represents a fatal flaw in PacifiCorp's proposed transition adjustment mechanism. Staff/700/Galbriath/20.

Q. Please comment on Mr. Jenks' statement that the Company's control over the timing of rate cases nullifies any potential benefit to customers of the temporary mismatch between fixed costs and variable costs.

A. Mr. Jenks acknowledges that the Company does project making significant capital expenditures that would likely offset any financial harm to customers resulting from the absence of updates to reflect a declining ratebase. CUB/200/Jenks/19. His claim that these capital investments are intermittent and that the Company will seek recovery as soon as a new investment becomes used and useful is not well founded. Contrary to Mr. Jenks' assertion, the timing of the majority of significant investments in new power plants, clean air equipment, and hydro relicensing is often nondiscretionary and is dictated by legislative mandates, requirements of a new FERC hydro license, load growth, and other external factors. It is not possible, nor reasonable, to attempt to coordinate these investments around rate case planning for the Company's six state jurisdictions. The Company maintains that in the current cycle of heavy capital expenditures, any temporary mismatch between fixed and variable costs resulting from the annual net power cost update is likely to benefit customers.

Q. Please respond to Mr. Jenks' comments regarding the mismatch of allocation factors for system costs.

A. Mr. Jenks appears to be arguing that an update of allocation factors – an update that reduces Oregon's allocated share of net power costs – is not a desirable outcome. Given Oregon's slower rate of growth relative to PacifiCorp's other jurisdictions, the Company believes that a partial update of allocation factors is beneficial because it results in an accurate allocation of power costs to Oregon customers.

Further, Mr. Jenks argues that an annual update of net variable power costs will take pressure off PacifiCorp to file a general rate case. This is highly unlikely, given the need for significant new investment in power supply and transmission resources over the next ten years. The Company will likely continue to experience lag between general rate cases which seek to include these new resources in rates.

Q. Both Mr. Falkenberg and Mr. Jenks argue that the Company's proposed RVM increases workload and regulatory burden. Please respond.

A. PacifiCorp is required to have a transition adjustment mechanism that allocates the impact of direct access participation on the Company's system to departing customers. UM 1081 and the RVM related components of UE 170 clearly demonstrate that development of a mechanism that is acceptable to all parties is extremely difficult, if not impossible. The Company's recognizes, and shares in, the added workload resulting from its proposed RVM. Given the inherently complex objective of the transition adjustment – an accurate determination of the value of a slice of an electric utility's system – the Company does not believe it would be possible to develop and implement an acceptable transition adjustment mechanism void of complexity and resulting workload. Absent a simpler solution, PacifiCorp relies on the fact that its proposed RVM is supported by OPUC Staff, who, like CUB & ICNU, will be litigating two RVMs and will be faced with the resulting workload increase.

TAM vs. RVM

Q. Mr. Jenks suggests in a footnote of his surrebuttal testimony that PacifiCorp's shift to calling its proposed mechanism an RVM is evidence that the Company's primary argument is that "PGE gets a mechanism, so PacifiCorp should too." Please respond.

A. Despite the Company's efforts to label its proposed mechanism as a Transition Adjustment Mechanism (TAM), the majority of the parties – both in formal discovery and in verbal discussions – continually referred to the mechanism as an "RVM". The name RVM appears to have become a generic name for adjustment mechanisms to facilitate direct access. PacifiCorp has worked with the parties for well over a year, in both UM 1081 and UE 170, to develop a transition adjustment mechanism that is acceptable. Characterizing the Company's primary argument as one as hollow as "PGE gets one so we should too" is not only without merit, but is also unfair.

Q. Does this conclude your sur-surrebuttal testimony?

A. Yes.

903 Tallman Testimony

Case UE-170
PPL Exhibit 903
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-Surrebuttal Testimony of Mark R. Tallman

Capital Additions/New Resource Rule Waiver

July 2005

Q. Are you the same Mark R. Tallman that filed direct testimony in this case?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address Mr. Falkenberg's surrebuttal testimony on PacifiCorp's new generation resources. I also address ICNU's arguments against PacifiCorp's request for a waiver of OAR 860-038-0080, the "New Resource Rule."

Q. Please summarize your testimony.

A. I respond to Mr. Falkenberg's assertion that the West Valley Lease compares unfavorably with long-term resource bids under RFP 2003-A and demonstrate that an extension of the West Valley Lease was the least cost option for PacifiCorp. I also defend PacifiCorp's request for a waiver of the New Resources Rule on the basis that it will result in lower, not higher costs, for customers. PacifiCorp's request was made on a timely basis and is well supported by the evidence in this case. PacifiCorp's decision to focus its efforts on UM 1182 and UM 1056 before working up a large customer opt-out proposal is consistent with the direction of the Commission in Order 05-133, indicating that these dockets are integral to the policies implicated by the New Resource Rule.

Q. Mr. Falkenberg criticizes PacifiCorp's decision to extend the West Valley Lease on the basis that PacifiCorp could have met this need at lower cost through RFP 2003-A. Do you agree?

A. No. While Mr. Falkenberg testifies that "there were other resources with overall costs that differed little from Currant Creek in RFP 2003-A," he does not specifically identify any such bid, nor does he conduct an analysis of the bid compared to the West Valley Lease.

In PPL Exhibit 904, I undertake such analysis. First, I selected Bid 135, the next most economic bid in the 2005 bid category RFP 2003-A to Currant Creek. The bid was for a 20-year physical tolling agreement, based on a 421 MW combined cycle unit to be online by June 2005. I compared this bid against the West Valley Lease for 3 years, June 2005 through May 2008, followed by a Lakeside-clone combined cycle combustion turbine (CCCT) to be online by June 2008, with the plant's life extending 35 years. I normalized all resources to 200 MW for comparison purposes.

This comparison demonstrates that bid 135 would have increased costs for customers. PPL Exhibit 904 shows that the net resource value for bid 135 is $134.6 million less economic than the West Valley/Lakeside-clone choice without including the costs of direct debt. If the costs of direct debt are included, the proxy resource is $181 million less economic than the West Valley/Lakeside-clone choice.

Q. What do you conclude from this analysis?

A. In UI 196, the Commission approved the West Valley Lease because it found that it met the "lower of cost or market" standard. This analysis also demonstrates that the West Valley Lease continues to meet that standard when compared against market alternatives from RFP 2003-A.

Q. ICNU contests PacifiCorp's waiver of the New Resources Rule on the basis that it should have been filed as early as the time of the CCN processes in Utah. Please comment.

A. PacifiCorp filed its request for a waiver in the round of testimony in UE 170 that immediately followed the Commission's order holding UM 1066 in abeyance and suggesting that utilities seek a waiver of the New Resource Rule in the interim. It is difficult to see how this is untimely, especially given the significant uncertainty that has surrounded the status and meaning of this rule since its adoption.

Q. ICNU claims that that the waiver would result in higher than market costs for the West Valley Lease and the Gadsby and Currant Creek projects. Do you agree?

A. No. All of these projects are priced below market at the time they were acquired. Application of the New Resource Rule would therefore result in higher, not lower costs, for these resources.

Q. Please provide evidence that waiver of the New Resource Rule for the West Valley Lease serves the interests of customers.

A. To supplement the record on this point, I have attached PPL Exhibit 905, the Final Report of Lands Energy Consulting, the independent monitor for the West Valley RFP, RFP 2004-X. The report states the following:

> "RFP procedures were careful and executed in a manner to insure clarity of information from bidders and a fair evaluation. LEC concurs with PacifiCorp that rescinding the termination of Leasco was the best alternative resulting from the RFP. Reliability concerns in the Salt Lake City area will be an issue until transmission upgrades can be completed. PacifiCorp is best served with continuing the lease through May of 2008." PPL Exhibit 905, page 2.

Q. Please provide evidence that waiver of the New Resource Rule for the Gadsby CTs serves the interests of customers.

A. As Staff notes in its testimony in support of PacifiCorp's waiver request, the Gadsby CTs were acquired at the same time and at similar cost as West Valley. Confidential PPL Exhibit 906 provides a comparison of Gadsby with the top-ranked bids received in PacifiCorp's 2001 RFP, which was the source of the West Valley Lease. The exhibit compares Gadsby, West Valley, the top-ranked bids and general market purchases (in the 8th column entitled "Physical," which summarizes the results for a market-based take or pay on-peak product delivered to Mona.) In this analysis, the Gadsby CTs had an overall relative ranking of number one.

Q. Please provide evidence that waiver of the New Resource Rule for Currant Creek serves the interests of customers.

A. In my direct and rebuttal testimony, I summarized the IRP, RFP and CCN processes that resulted in the Currant Creek resource. Staff notes in its testimony that it has scrutinized the economic evaluation conducted by the Company in connection with Currant Creek and concluded "that the plant was the least cost option and will provide benefits to customers." Staff/800, Wordley/5.

Q. ICNU contends that the Commission should not grant the waiver request because PacifiCorp has not offered a large customer opt-out proposal or enhancements to the competitive bidding process. Please respond.

A. The Commission's order holding UM 1066 in abeyance noted the importance of the outcomes of UM 1182, the competitive bidding docket, and UM 1056, the IRP docket, to the issues implicated by the New Resource Rule. See Order 05-133 at 2. Before commencing serious work on an opt-out or other proposal, PacifiCorp has focused its efforts on these dockets, with the hope that they will provide important policy direction to inform the application, design and feasibility of an opt-out proposal.

Q. Does this conclude your testimony?

A. Yes.

904 Tallman Exhibit

Case UE-170
PPL Exhibit 904
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

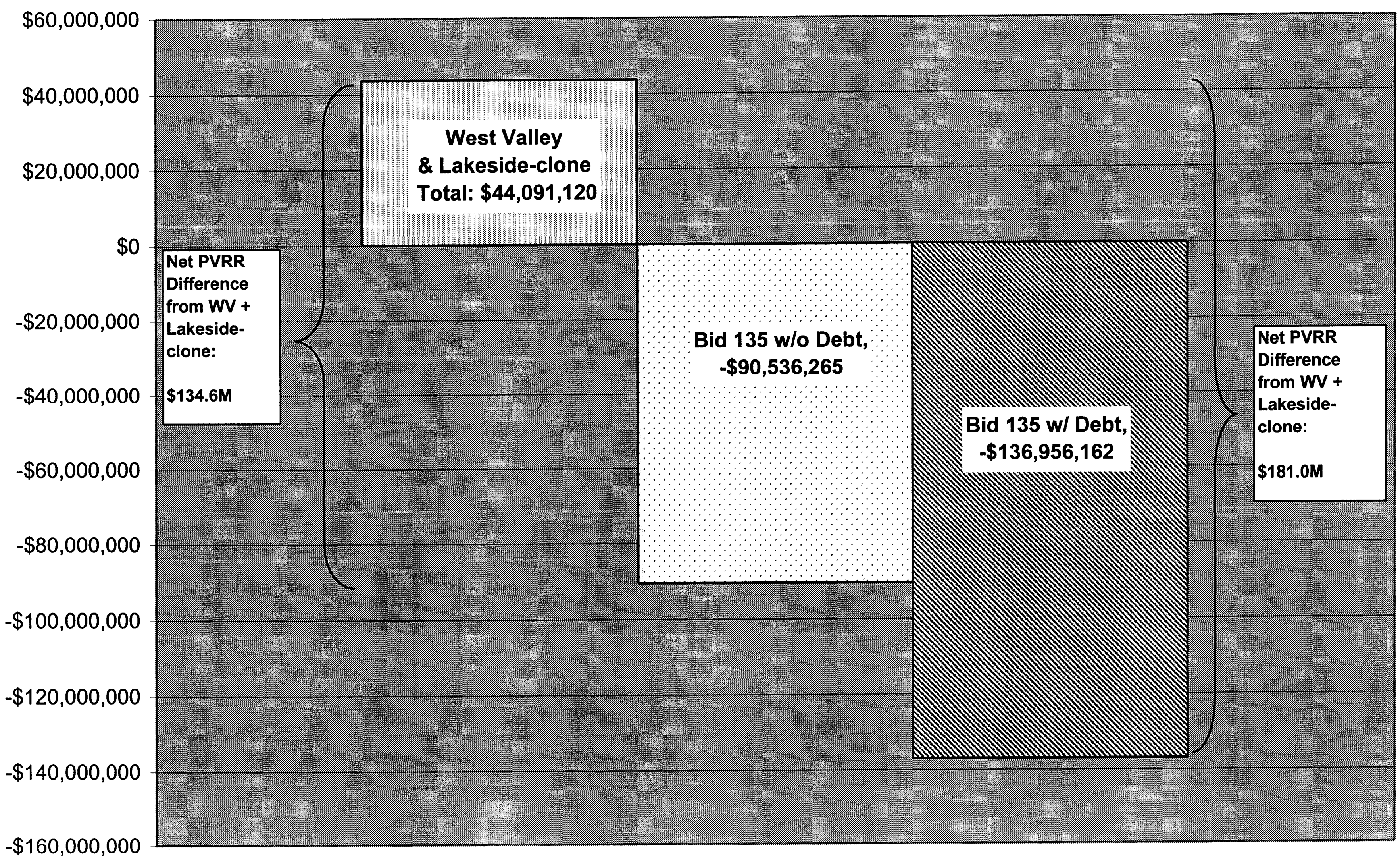
PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of Mark R. Tallman

Present Value Revenue Requirement

July 2005

Present Value Revenue Requirement - Normalized on a 200MW basis



905 Tallman Exhibit

Case UE-170
PPL Exhibit 905
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of Mark R. Tallman

Lands Energy Consulting's Final Report On PacifiCorp's RFP 2004-X

July 2005

PUBLIC VERSION

LANDS ENERGY CONSULTING'S FINAL REPORT
On PACIFICORP'S RFP 2004-X

Lands Energy
CONSULTING

PACIFICORP

December 28, 2004

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This public report details the observations and finding of Lands Energy Consulting ("LEC") regarding the PacifiCorp Request for Proposals 2004X ("RFP"). PacifiCorp released the RFP to seek potential alternatives to the continuation of a lease from the West Valley Leasing Company ("Leasco"). Leasco is a subsidiary of PPM Energy, an affiliate of PacifiCorp. In May of 2004 PacifiCorp exercised the first of two options to terminate Leasco. The company had the option to rescind this termination on or before September 30, 2004. Through the RFP PacifiCorp sought alternatives that would serve customer load in Utah reliably and at lower cost than Leasco.

PacifiCorp hired LEC to act as an independent monitor of the RFP process. LEC was tasked with validating that cost assumptions and modeling of Leasco verses other proposals was fair and unbiased. LEC was also asked to audit the PacifiCorp model and confirm that modeling and other RFP processes were consistently applied to all bids. LEC was also tasked with offering suggestions for improvements to the RFP process.

This report is organized into the following sections:

- I. Background of the RFP and procedural review.
- II. Model validation.
- III. Transmission and reliability considerations
- IV. Bid Evaluation
- V. Conclusions.

The RFP was released on July 19, 2004 to a large number of potential bidders involved in wholesale electric power trade in the WECC. Intent to bid forms were due on July 28, 2004. Six counterparties submitted intent to bid forms. Proposals were due on August 9, 2004. PacifiCorp received three bids from one bidder and two other bidders submitted one bid each.

The requirements for proposals for the RFP were designed to meet the specific resource attributes needed upon termination of Leasco. Leasco is located within a load serving area around Salt Lake City, Utah that is experiencing rapid load growth. Transmission import capability into this area is limited and planned upgrades are not due to be completed before 2008. The RFP called for supply that would be delivered to this area or, if delivered to a nearby import point, would offer liquidated damages in the event of non-delivery. The RFP also restricted proposals to those not involving PacifiCorp affiliates or delivery from PacifiCorp affiliate-owned facilities.

On August 9, 2004 LEC received the bids and reviewed them for conformance to the RFP. One bid involved a transaction from a facility owned by a PacifiCorp affiliate and was determined to be not in conformance with the RFP. One bidder offered three market based transactions delivered at an acceptable import point. Two of these bids did not follow RFP requirements for liquidated damages and were deemed by LEC to be nonconforming. The final offer from this bidder, a three year toll, did provide for liquidated damages and was evaluated. The final bid was for a Greenfield project in the Salt Lake City area with a term of 12.6 years and proceeded to the evaluation phase of the RFP.

The model used by PacifiCorp in this RFP process is a thorough spreadsheet model. LEC did not perform an exhaustive evaluation of the model but did assess the capabilities of the tool with sufficient rigor to be convinced that it was an effective evaluation tool. Leasco economics that were modeled reflected contractual and operational data accurately. Market curves and other model inputs were reviewed and found to be reasonable. The economic comparison metric, present value revenue requirement normalized for capacity[1] was reviewed and LEC agrees that this is a fair and effective means of comparing bid economics.

The two conforming bids evaluated were compared to Leasco economics as the Next Best Alternative ("NBA"). The 12.6 year Greenfield development potentially would have provided for needed reliability support in the Salt Lake City area but the valuation of this bid resulted in economics that were less favorable than Leasco's. The bid was therefore removed from consideration. The three year toll was proposed for delivery at an acceptable import point under the RFP. The absence of a delivery in the Salt Lake City area did however create system reliability issues. Under the Network Transmission service contract between PacifiCorp Transmission and the utility, PacifiCorp is required to provide notice of a material change affecting a network generating resource. PacifiCorp requested a study from the PacifiCorp Transmission organization to determine the reliability impacts and remedies for removal of Leasco. Additionally, LEC advised PacifiCorp to value the capability for Leasco to be used for operating reserves. When the value of Leasco and the reliability costs of its termination were compared to the remaining bid PacifiCorp made the determination that retention of Leasco was the preferred alternative. The company submitted a notice to PPM Energy rescinding the termination of Leasco on September 28, 2004.

PacifiCorp provided LEC with direct access to subject area experts as needed to perform the role of monitor and auditor of the RFP process and technical evaluation. LEC observed a high level of technical expertise among the PacifiCorp quantitative staff. RFP procedures were careful and executed in a manner to insure clarity of information from bidders and a fair evaluation. LEC concurs with PacifiCorp that rescinding the termination of Leasco was the best alternative resulting from the RFP. Reliability concerns in the Salt Lake City area will be an issue until transmission upgrades can be completed. PacifiCorp is best served with continuing the lease through May of 2008. In the interim LEC makes the following recommendations:

- Expand RFP modeling to capture real-time option value of alternatives. The quantitative staff is proficient it this area and the PacifiCorp model should be capable of representing this value. Future resource selections should take this important part of resource value into account.

[1] This will be discussed in detail in the main body of the report.

- Notify PacifiCorp Transmission to plan in their control area reliability studies for a possible removal of Leasco as a network resource on May 31, 2008.
- Finally we recommend that PacifiCorp, in planning in its upcoming IRP, evaluate the economics of removal of Leasco from their resource portfolio on May 31, 2008.

I. Background of the RFP and Procedural Review

In 2001 PacifiCorp contracted with Leasco for a 15-year lease of a power plant with 200 MWs of generating capacity near Salt Lake City. The project utilizes LM6000 generating technology. Within the lease agreement are two separate options for PacifiCorp to terminate the lease early and an option to purchase the project outright for pre-determined amounts.

PacifiCorp exercised its first option to terminate Leasco (effective May 31, 2005) in May 2004. PacifiCorp was entitled to rescind this notice of termination by notifying PPM Energy of this decision by September 30, 2004. In order to decide whether to rescind the termination notice, PacifiCorp conducted RFP 2004-X to seek proposals to replace Leasco with a resource capable of delivering electric power to loads in Utah in a manner that was more economic with equivalent reliability. The Leasco economics would be used as a Next Best Alternative ("NBA") against which to compare bids submitted.

RFP 2004X was issued on July 19, 2004. In this solicitation PacifiCorp was very specific about the load serving power supply that would be needed to replace the leased resource. Leasco fits a particular need PacifiCorp has in the Salt Lake City area. This area ("Load Pocket") is unique in that its population and electricity needs are growing rapidly while there is limited transmission capacity to import power into the area. Import capability into the Load Pocket and reliability concerns for load service in this area were an important part of evaluating alternatives. PacifiCorp transmission has transmission upgrades planned, but many of these upgrades are not due to be completed until 2008 and later.

While being very specific in the RFP about the physical location to which any proposed supply must deliver, PacifiCorp was prepared to evaluate alternative delivery points within certain specifications, and indicated it would consider such alternate delivery points. These points constituted transmission interconnections in the PacifiCorp eastern control area at which power could be delivered into the load pocket. Due to limits to import capability and concerns about reliability impacts of failure to deliver, PacifiCorp conditioned acceptance of proposals at these points on inclusion of a provision for reimbursement of 125% of liquidated damages in the event of curtailment.

RFP 2004X stated that offers for firm power needed to have start dates of no later than June 1, 2005 and be for terms of either 3 years, 3 years with a 9-year extension option, or "up to" 12 years with a 3-year minimum. PacifiCorp told bidders that all bids with terms equal to 3 years would be benchmarked against the June 1, 2005 through May 31, 2008

Leasco economics, and all bids with terms greater than 3 years would be benchmarked against the June 1, 2005 through December 31, 2017 lease and market economics.

Major milestones in the RFP process were as follows:

- PacifiCorp released the RFP to a large number of entities involved in the wholesale trade of electric power in the WECC on July 19, 2004.
- On July 26, 2004 the company hosted a bidders' conference call to provide potential participants with the opportunity ask questions or to request clarifications to the content of the RFP.
- PacifiCorp received six Intent to Bid Forms by the due date of July 28, 2004.
- On August 9, 2004 PacifiCorp received five bids from three different bidders. LEC began work as independent monitor.
- September 27, 2004 PacifiCorp completed the evaluation of bids and informed bidders that their offers were not selected.
- PacifiCorp notified PPM Energy of the decision to rescind the termination of Leasco.

On August 9, 2004 LEC consultants were present in PacifiCorp's offices and received the bids. In keeping with the scope of work as independent monitor LEC made copies for distribution to PacifiCorp legal and credit departments. The consultants then evaluated the bids to determine conformance with the bid criteria established in the RFP. There were concerns with three of the five proposals received regarding to conformance with critical requirements of the RFP. LEC recommended that PacifiCorp review these issues and consider these bids non-conforming. After additional internal review, PacifiCorp made the determination that these bid were non-conforming and dropped them from consideration. LEC agrees with this decision. The remaining two bids were then compared to the Leasco NBA as will be discussed in Section IV of this document.

II. Model Validation

Pursuant to the Statement of Work for Independent Review of 2004-X RFP Process, LEC reviewed the spreadsheet model used to evaluate the value of Leasco and the methodology by which PacifiCorp intended to compare Leasco to other similar offers for capacity and energy.

LEC with a working model provided by PacifiCorp verified the following items:

- The accuracy of input data matching the terms of Leasco agreement and the operating characteristics of the LM6000s.
- The reasonableness of modeling methods and assumptions.
- The reasonableness of comparing offers using the PVRR divided by the PV capacity of the project.

LEC found the PacifiCorp model to be a reasonable reflection the terms of Leasco and the financial impacts of the lease agreement relative to prevailing market prices. The model, however, is quite a thorough spreadsheet model. The review was not exhaustive but was sufficient to establish that this tool could be used for comparing alternatives in an un-biased manner. Key findings in each of the issue areas are summarized below:

Accuracy of Input Data matching the terms of Leasco

LEC validated the following inputs:

- Capacity Payment
- Variable O&M
- Fixed O&M
- Property Taxes and Insurance
- Heat Rates

Inputs were either explicitly in the Leasco contract or provided from historical operational data.

Are Market Assumptions Reasonable

LEC validated the following assumptions:

- Natural Gas Price Curve
- Electric Power Price Curve

LEC confirmed price curve assumptions as being in keeping with third party price information and reflective of prudent utility practice.

Reasonableness of Modeling Methods and Assumptions

LEC evaluated the reasonableness of the following:

- Dispatch logic for on and off peak hours, heat rate and price curves
- Appropriateness of dispatch outcomes for Leasco
- Appropriateness of dispatch outcomes for other bids

LEC confirmed that the model logic was applied in a reasonable manner in evaluating proposal characteristics relative to market and that the modeling treated all bids in an un-biased manner.

Reasonableness of comparing offers using the PVRR divided by the capacity of the project

LEC reviewed the convention of using the PVRR divided by the PVKW as the comparative metric for making resource selections. It is important to understand the need to normalize the market comparison on a present value basis to account for resource options of differing installed capacities. Other utilities have used a method where the value net of cost is levelized and divided by the installed capacity (or average energy production) to normalize the value for the size of the project. In this case, PacifiCorp computes the present value of the revenue requirement (PVRR) and divides by the present value of the capacity over time (PVKW). This is generally equivalent to the first method, and is wholly comparative as a selection metric. LEC finds this method sound and in keeping with industry practice.

Conclusion

The spreadsheet model employed by PacifiCorp for comparing alternatives against the Leasco NBA was appropriate, reasonable, and did not result in any undue bias in favor of Leasco. In fact, the model under-valued Leasco when compared to other options that did not have the short-term flexibility to be dispatched against the real-time hourly markets. Model inputs for the NBA and evaluated bids were accurate and market assumptions were reasonable.

III. Transmission and Reliability

Leasco which is located within the Load Pocket is a declared Network Resource ("NT") under the PacifiCorp Open Access Transmission Tariff. As such it is subject to dispatch decisions by the PacifiCorp Transmission organization as needed for reliability purposes. As required under section 31.6 of the tariff PacifiCorp advised PacifiCorp Transmission of a possible material change resulting in the termination of Leasco as an NT resource. This requirement allows the transmission group to determine if the removal of a network resource will have impacts on service reliability. PacifiCorp transmission responded to this notice by determining the level of deterioration to reliable load service within the Load Pocket and to suggest remedies that could be implemented to mitigate the deterioration. PacifiCorp transmission reported that, using 2005 load projections, the amount of load that must be shed for critical double contingency outage increases from 60 MW to 200 MW and the hours of exposure increases from 100 hours to 200 hours if Leasco were replaced with power purchased at a delivery point not within the Load Pocket. PacifiCorp Transmission stated that mitigation could be accomplished through acceleration of $21 million in capital projects earmarked for 2008 and reconductoring a 138kV line at a cost of $500,000. Leasco economics reflected the benefit of not needing to accelerate the $21 million project and not needing the $500,000 project at all. PacifiCorp Transmission in their report indicated that the possibility of delays in completing mitigation measures represented a residual reliability risk factor.

IV. Bid Evaluation

As discussed in Section I of this document, three of the bids offered into RFP 2004X were determined by a review of LEC and PacifiCorp staff to not be in conformance with the requirements of the RFP. The two remaining bids were compared to the appropriate Leasco NBA. These two bids included a 12.6 year toll from and new resource and a 3 year toll delivered to a point outside of the Load Pocket.

PacifiCorp evaluated the proposed resources and Leasco by simulating the dispatch of these resources into a forward market. The forward market chosen was the most relevant electricity hub within the context of the larger WECC market. Mona was chosen as the most relevant geographic electricity hub. The cost associated with each proposal and

Leasco was compared against the forward Mona market curve and the resources were dispatched when economic. The resultant value of the dispatched generation was compared against the costs of the resource. PacifiCorp's revenue requirement for costs under each proposal was netted against the Mona market value of the energy in an attempt to put a proxy value on a given proposal's net margin relative to this market. The present value of this comparison was computed for each resource ("PVRR"). All proposals were then normalized by dividing the PVRR by the present value of the proposed capacity. The resulting comparative annuity measurement unit is dollars PVRR per kW-mo ("$PVRR-D/kW-mo").

12.6 Year Tolling Agreement

This bid was based on building a new generating resource within the Load Pocket defined by the RFP. There were a number of development issues associated with this project that called into question the ability of the project to meet the geographic and time requirements specified in the RFP. Nevertheless, while due diligence was being conducted to clarify and mitigate these issues, PacifiCorp evaluated the economics of the proposal. In the end, the issues that called into question the ability of the project to meet the geographic and time requirements specified in the RFP were moot because it became apparent that the economics of the proposed transaction were inferior when compared to 12.6 years of the Leasco NBA.

3 Year Tolling Agreement

This bid was for a 3 year tolling agreement delivered at Mona rather than inside the Load Pocket. The bidder provided for liquidated damages as required in the RFP. Economics associated with this bid were compared with 3 years of Leasco economics. This bid brought into consideration the transmission mitigation measures described in Section III. Costs associated with these measures were assessed to the bid economics. The LM 6000 generating units that make up the Leasco project are capable of quick starts. They can be used to meet reliability reserves requirements. During the course of the evaluation LEC suggested that PacifiCorp include this value when establishing Leasco economics. The alternative to holding reserves on Leasco is to hold them on low cost units. Holding these low cost units for reserves represents a significant opportunity cost to PacifiCorp. The precise value of using Leasco for reserves is difficult to determine. PacifiCorp developed a range of values. When consideration of base economics of the 3 year toll, the lack of reserves value, transmission mitigation costs and residual reliability issues present with this bid were considered, PacifiCorp determined that the NBA, Leasco was the preferred alternative.

V. Conclusions

Findings

LEC finds that the logic and valuation methodologies used by PacifiCorp in its analysis of the bids submitted pursuant to the RFP 2004X resulted in a fair and unbiased comparison of the bids against the Leasco NBA. LEC reviewed the content of each bid submitted and concurs with the finding of non-conformance of three of the bids. LEC reviewed the evaluation model and model inputs used in the valuation of each conforming bid and participated in phone calls and written correspondence between PacifiCorp and the bidders. It was observed that the evaluation model and other RFP processes have been consistently applied to all bids and the NBA.

The 12.6 year tolling agreement had inferior economics versus the NBA. The 3 year tolling agreement had economics that were slightly better than, to quite a bit worse than the NBA when the difference in reliability and reserve value between the bid and the NBA was taken into account.

Recommendations

LEC recommends expanding RFP modeling to capture real-time option value of alternatives. The quantitative staff is proficient it this area and the PacifiCorp model should be capable of representing this value. Future resource selections should take this important part of resource value into account.

PacifiCorp should notify PacifiCorp Transmission to plan in their control area reliability studies for a possible removal of Leasco as a network resource on May 31, 2008.

Finally LEC recommends that PacifiCorp, in planning in its upcoming IRP, evaluate the economics of removal of Leasco from their resource portfolio on May 31, 2008.

906 Tallman Exhibit

Case UE-170
PPL Exhibit 906
Witness: Mark R. Tallman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of Mark R. Tallman

Comparison of Gadsby with the Top-Ranked Bids Received in PacifiCorp's 2001 RFP

THIS MATERIAL CONFIDENTIAL SUBJECT TO PROTECTIVE ORDER

July 2005

THIS PPL EXHIBIT 906
UNDER SEPARATE COVER
SUBJECT TO PROTECTIVE ORDER

Case UE-170
PPL Exhibit 1106
Witness: Daniel J. Rosborough

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-Surrebuttal Testimony of Daniel J. Rosborough

Pensions and Benefits

July 2005

Q. Are you the same Daniel J. Rosborough who previously filed direct and rebuttal testimony in this proceeding?

A. Yes.

Q. What is the purpose of your sur-surrebuttal testimony?

A. I testify to PacifiCorp's final 2005 pension expense and explain why this should be used as the basis for setting rates in this case, instead of more dated expense history. I address the surrebuttal testimony of Staff witness Mr. Dougherty and ICNU witness Mr. Selecky on these issues. Because the parties settled employee benefits in the Second Partial Stipulation after the filing of PacifiCorp's rebuttal testimony, my testimony no longer addresses this issue.

Q. Please summarize your testimony regarding PacifiCorp's pension related expenses.

A. I confirm that the Company's final FAS 87 expense for 2005 was $49.9 million, $16.9 million higher than the $33 million expense level proposed by Staff in this case. I confirm that the Company's final FAS 106 expense was $24 million, $3 million higher than the expense level proposed by Staff in this case. I demonstrate how Staff's and ICNU's use of 2004 expense, which ignores the significant expense increases the Company has experienced since that time, undermines the Commission's policy of permitting recovery of FAS pension expenses.

To address Staff's concerns that the Company's projected FAS expenses are inflated, I propose that the Company use a balancing account to track the annual difference between actual 2006 FAS pension expense and the Company's proposed expense levels for FAS 87, FAS 106 and FAS 112. The Company would refund or collect the under- or overcollection, if any, to customers. In this manner, the Commission can ensure full FAS cost recovery, without fear of setting costs on a going-forward basis at unreasonably high levels.

I address the unreasonableness of Staff's and ICNU's proposed partial disallowance of the Company's projected 2006 contribution to the IBEW Local 57 plan. To respond to concerns that the Company's projected contribution may not materialize, however, I propose using the balancing account approach for this expense as well, tracking the annual difference between the Company's $3 million projected expense and its actual expense, with rate adjustments to follow for under- or over collection.

Lastly, to streamline the issues in dispute in this case, PacifiCorp agrees to Staff's adjustment of $263,054 for pension administration expenses.

PacifiCorp's Final 2005 Pension Expense and New Projected 2006 Pension Expense

Q. What is the Company's final 2005 FAS 87 pension expense?

A. PacifiCorp's actuarially determined 2005 FAS 87 expense is $49.9 million. As reported in my rebuttal testimony, the Company's final FAS 87 expense for calendar 2005 is $55.0 million. This expense includes PacifiCorp and other non-regulated entities. I estimated an allocation of $48.4 million to PacifiCorp in my rebuttal testimony; the actual allocation is $1.5 million higher, $49.9 million. These 2005 FAS 87 expenses are now final and will be used in PacifiCorp's accounting and financial reporting for 2005.

Q. What is the Company's final 2005 FAS 106 retiree medical expense?

A. PacifiCorp's actuarially determined 2005 FAS 106 expense is $24 million. As reported in my rebuttal testimony, the Company's final FAS 106 expense for calendar 2005 is $29.9 million. As in the case of the Company's FAS 87 expense, the Company's total expense includes PacifiCorp and other non-regulated entities. I estimated an allocation of $24.1 million to PacifiCorp in my rebuttal testimony; the actual allocation is slightly lower, $24 million. These 2005 FAS 106 expenses are now final and will be used in PacifiCorp's accounting and financial reporting for 2005.

Q. Do you propose to set PacifiCorp's FAS 87 and FAS 106 pension costs in this case using PacifiCorp's actual pension expenses for 2005?

A. Yes. In both his direct and surrebuttal testimony Mr. Dougherty has endorsed setting pension costs in this case using "the most recent full year computation of costs." Staff/1100, Dougherty/3. The most recent full year computation of costs is now 2005. The Commission should set the Company's FAS 87 expense in this case at $49.9 million and its FAS 106 expense at $24 million. In this manner, the Commission can avoid setting pension costs using the "calculations and estimates" about which Mr. Dougherty is concerned, *id.*, while still allowing fair cost recovery levels for PacifiCorp.

Q. **Does Mr. Selecky oppose the updating of PacifiCorp's FAS pension costs in this manner?**

A. Yes. Mr. Selecky argues that it is inappropriate for PacifiCorp to revise its cost estimates after making its rate filing. In PacifiCorp's experience, however, the

Commission has commonly permitted the updating and refining of costs post-filing—either by the utility and or by other parties—to ensure that rates are set using the most recent and accurate cost data possible.

Recovery of Pension Costs Using Actuarially Determined FAS Expense

Q. Is there any disagreement among the parties that the Commission should determine PacifiCorp's pension costs using its actuarially determined FAS pension costs?

A. No. Neither Mr. Dougherty or Mr. Selecky contest this fundamental point in their direct or surrebuttal testimony. Indeed, in his direct testimony, Mr. Dougherty agreed that FAS 87 is the best measure of annual pension costs and notes that the Commission has previously used FAS 87 in setting rates. Staff/400, Dougherty/3. *See, e.g., In re PacifiCorp*, UM 1073, Order 03-233 at Appendix A, p. 2 (April 18, 2003) ("actuarially determined FAS pension costs are generally recoverable in rates as has been the case in past rate cases.")

Q. Are the Staff and ICNU adjustments to PacifiCorp's pension costs consistent with this position?

A. No. It is inconsistent to endorse actuarially determined FAS expense as the appropriate measure of pension costs for ratemaking and then make or defend adjustments by disputing or mischaracterizing aspects of FAS pension expense methodology.

Q. Please provide an example.

A. Mr. Dougherty contends that PacifiCorp's "actual pension costs" have not increased due to the lowering of the discount rate in the actuarial calculations underlying PacifiCorp's FAS 87 expense and the corresponding increase in FAS 87 expense. Staff/1100, Dougherty/3-4. Mr. Dougherty's suggestion that FAS pension expense does not reflect "actual pension costs," however, is at odds with the Commission's position that FAS pension expense is the most accurate method of measuring actual pension costs. While calculations underlie the actuary's determination of the FAS expense, this expense is the "cost" (and not just a calculation) reflected on PacifiCorp's books, in its financial reporting and in its rates.

Q. Does Mr. Dougherty rely on similar inconsistent reasoning in disputing the existence of PacifiCorp's significant pension losses in the last two years?

A. Yes. PacifiCorp's current FAS pension cost in rates is $16.3 million. Its FAS 87 pension cost in 2004 was $31.5 million, resulting in a loss of $15.2 million. As noted above, PacifiCorp's 2005 FAS expense was $49.9 million, resulting in a loss of $33.6 million. In the face of almost $50 million in losses, Mr. Dougherty claims that PacifiCorp did not under-recover in rates because "actual returns on PacifiCorp's plans have exceeded payments to retirees the past two years." Staff/1100, Dougherty/12. Defining pension costs in this context as plan returns minus plan payments is a different and less accurate means of measuring pension costs than using FAS pension costs because, among other things, it does not take into account plan liabilities. When actuarially determined FAS pension costs are the cost measure used in rates, then a shortfall between PacifiCorp's actual FAS expense and that reflected in rates constitutes a loss to PacifiCorp.

Q. Are there other areas where Mr. Dougherty's arguments fail to acknowledge the manner in which FAS pension costs are calculated?

A. Yes. Mr. Dougherty asserts that 2006 FAS pension costs will be lower than in 2005 because of stronger than assumed returns in 2003-04. As I pointed out in my rebuttal testimony, however, actual returns (as opposed to assumed returns used in "projections") on Plan assets are used in the actuary's expense calculation. The positive returns in 2003-04 have already been factored into the Company's FAS pension expense in this case. On a going forward basis, it is unlikely that returns in 2005 will match 2003-04 returns. As of June 30, 2005, the Dow Jones index was down 4.7 percent.

Q. **Mr. Dougherty and Mr. Selecky contest the reasonableness of the 5.75 percent discount rate assumed in PacifiCorp's FAS pension costs. Is this another area where their positions fail to acknowledge the manner in which FAS pension costs are actually set?**

A. Yes. By design under FAS 87, the Company has little discretion to set the Plan's discount rate. FAS 87 requires the discount rate to be reflective of high-quality fixed-income investments (corporate bonds rated Aa or better per SEC guidelines) in effect at the Plan's measurement date. As Mr. Dougherty notes, some interest rate indices have increased in 2005. Others, specifically Moody's Corporate Aa index, have decreased. As of December 31, 2004, the Moody's Aa rate was 5.66 percent; as of June 30, 2005, it had decreased to 5.01 percent, both below the 5.75 percent discount rate used in PacifiCorp's Plan.

Both the Company's auditors and actuary must agree that the discount rate is reasonable. As noted by Mr. Dougherty, those charged with overseeing FAS pension cost compliance—auditors and the SEC—take a conservative approach to "prevent low reporting of pensions on financial statements." Staff/400, Dougherty/13. This ensures the accuracy and consistency of FAS pension expense, which is presumably one of the primary reasons that the Commission has used FAS pension expense to set pension costs in rates.

Q. **Mr. Dougherty testifies that PacifiCorp has influence over the discount rate, that PacifiCorp could support a 6 percent discount rate and that customers should not be required to bear the costs of PacifiCorp's "passive" approach to setting the Plan discount rate. Staff/1100, Dougherty/10. Please comment.**

A. To the extent that PacifiCorp has any influence in setting the assumptions used in calculating its FAS pension costs, it uses these to lower, not increase, Plan expense. PacifiCorp is not passive in this process because it has a strong interest in lowering costs (or mitigating cost increases) by setting the discount rate at the highest level allowable under the FAS guidelines. In practice, therefore, the discount rate is the highest rate that the Company's auditors and actuary will approve. In 2005, the Company's auditors Price Waterhouse Coopers (PWC) would not approve a discount rate higher than 5.75 percent, even though PacifiCorp argued that a higher discount rate might be justified.

Q. **Is it reasonable to set FAS pension costs in this case that assume a 5.75 percent discount rate?**

A. Yes. As noted above, the fact that Moody's Corporate Aa index rate as of June

30, 2005 is 5.01 percent demonstrates that PacifiCorp's use of a 5.75 percent discount rate was more prudent than a 6 percent rate. Additionally, Mr. Dougherty cites significant evidence that a 5.75 percent discount rate is reasonable and "in line with market conditions," Staff/400, Dougherty/8, including: (1) PWC's recommendation that its clients not use a discount rate exceeding 5.75 percent, *id* at 13; (2) Towers Perrin's 12/31/04 benchmark discount rate of 5.83 percent, *id.* at 7; (3) Idaho Power's use of a 5.75 percent discount rate in UE 167, *id.*; (4) Staff's observation of present discount rates "ranging from 5.75 percent to 6.25 percent", *id* at 8; and (5) Staff's notation that the largest group of the clients of PacifiCorp's actuary Hewitt Associates are using a 5.75 percent discount rate, Staff/1100, Dougherty/10.

Other Issues

Q. In his adjustment for FAS 106 expense, Mr. Dougherty disallows as unreasonable costs associated with a Plan amendment designed to continue to share some, but not more than half, of retiree medical inflation for employees who retired after 1990. Can you respond to this adjustment?

A. Yes. This Plan amendment is limited in scope and cost, but has a significant positive impact on PacifiCorp's retirees. The amendment increases the amount of the monthly cost of coverage paid by the Company for employees who retired after 1990, starting January 1, 2006. This change will affect only retirees who opt for the lowest cost coverages. The Company cost will then remain unchanged and retirees will pay the full amount of increase in 2007. Starting in 2008, the amount the Company pays will be shared equally each year, though the Company's cost will not increase more than 5% in any year.

Without this amendment, in some cases, PacifiCorp's retiree medical coverage would have totally consumed a retiree's pension check after only a few more years of retirement. This amendment does increase the costs of the Plan, but we are continuing to make incremental changes each year to the retiree medical program plan design to help maintain the Plan's overall cost.

While Mr. Dougherty's research is accurate that many employers are not increasing retiree medical benefits, some companies are making changes similar to PacifiCorp to address the impact of medical inflation and the significant cost shifts that would result otherwise. From PacifiCorp's perspective, the costs of this Plan amendment were relatively low when considered against the impact the change has had on the quality of medical coverage for PacifiCorp's retirees.

Q. Has Mr. Dougherty changed his position on the Company's IBEW Plan contribution?

A. Yes. Previously, Mr. Dougherty opposed any costs associated with this contribution. Mr. Dougherty now agrees that rates should reflect $1.5 million contribution. While this movement is helpful, the $1.5 million in costs is only half of the $3 million contribution PacifiCorp projects in 2006, and less than half of its three-year average of $3.5 million for its IBEW Plan contributions.

Q. Does the Company have 2005 FAS 112 expense available at this time?

A. No. FAS 112 expense for 2005 will not be available for several months. For this reason, we continue to rely upon the Company's originally filed FAS 112 expense of $6.8 million.

Q. What is the Company's position on Mr. Dougherty's adjustment for pension administration expense?

A. To streamline the issues in dispute in this case, PacifiCorp has agreed to accept this adjustment totaling $263,054.

Q. Mr. Selecky asserts that the Company should have used a CPI index rate of 2.6 percent for compensation increases reflected in Plan expense instead of 4 percent. Please respond.

A. PacifiCorp's most recent annual compensation increase for Plan participants was 5.75 percent. PacifiCorp's use of 4 percent for its Plan expense is reasonable in light of its actual experience.

Balancing Account

Q. Please address Staff's concern that PacifiCorp's FAS pension costs could change significantly if its actuary uses different assumptions for 2006.

A. PacifiCorp's FAS pension costs for 2006 are more certain than many other costs in the case precisely because these costs are actuarially determined. The Company's actuary, Mr. Kopec, has already testified that he expects PacifiCorp's 2006 FAS pension costs to match or exceed its 2005 FAS pension costs.

Q. Nevertheless, could a balancing account be used to address concerns that PacifiCorp's 2006 FAS pension costs are overstated or subject to change?

A. Yes. In its last rate case, PacifiCorp proposed the use of a balancing account to track actual pension costs in rates. In *In re NW Natural*, Order 03-507 at 3, the Commission approved a Stipulation that permitted NW Natural to recover its full-filed pension expense, with deferred accounting to ensure against over collection.

To address the concerns of Staff and ICNU about the level of FAS pension expense for 2006, PacifiCorp proposes to use a balancing account to track the differences in projected and actual FAS 87, FAS 106 and FAS 112 pension expense, as well as the amount of its IBEW contribution. The balancing account would operate symmetrically (i.e., tracking over collection and under collection of pension costs and making rate adjustments accordingly.) Because PacifiCorp's FAS pension expense is a variable, non-discretionary expense item determined by independent auditors and actuaries, PacifiCorp believes that the cost is well suited for balancing account treatment.

Q. Does this conclude your sur-surrebuttal testimony?

A. Yes.

1107 Rosborough Exhibit

Case UE-170
PPL Exhibit 1107
Witness: Daniel J. Rosborough

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of Daniel J. Rosborough

Allocation of Fiscal Year 2005 and 2006 Expenses

July 2005

PacifiCorp

Allocation of Fiscal Year 2005 and 2006 Expenses

	Fiscal Year 2005 Expense	Fiscal Year 2006 Expense
PacifiCorp Retirement Plan		
Bridger Coal Company	$ 1,916,939	$ 2,095,568
Glenrock Coal Company	177,073	171,889
Energy West	1,123,414	1,151,129
Subtotal Mines	$ 3,217,426	$ 3,418,586
Credit Union	$ 67,554	$ 102,572
Enstor	96,774	135,187
PERCO	57,941	86,805
PFS	22,546	30,871
PPM	834,952	1,278,533
PKE	N/A	122,554
Subtotal Non-Regulated	$ 1,079,767	$ 1,756,522
Electric Operations	$ 31,477,807	$ **49,854,892**
Total	$ 35,775,000	$ 55,030,000

Case UE-170
PPL Exhibit 1209
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-Surrebuttal Testimony of William R. Griffith

Rate Spread/Rate Design

July 2005

Q. Are you the same William R. Griffith who presented direct testimony in this case?

A. Yes, I am.

Purpose of Testimony

Q. What is the purpose of your sur-surrebuttal testimony?

A. My sur-surrebuttal testimony addresses the following:

1. Presentation of revised exhibits to include the effects the Klamath River Basin customers remaining on contract rates, and reflecting the revised revenue requirement change;
2. Billing period variability; and
3. Rate Spread.

Updated Exhibits

Q. Have you prepared any updates to your exhibits filed in the direct case?

A. Yes. Updated exhibits are included as PPL Exhibit 1210, PPL Exhibit 1211, PPL Exhibit 1212 and PPL Exhibit 1213.

Q. Please describe PPL Exhibit 1210, PPL Exhibit 1211, and PPL Exhibit 1212.

A. PPL Exhibit 1210 shows the revised rate spread excluding the effects of the elimination of Schedule 94, adjusted for the revised revenue requirement, and including the assumption that the Klamath River Basin customers are billed at contract rates. PPL Exhibit 1211 shows the revised rate spread including the effects of the elimination of Schedule 94, adjusted for the revised revenue requirement, and including the assumption that the Klamath River Basin customers are billed at contract rates. PPL Exhibit 1212 contains the adjusted forecast billing determinants and present and proposed base rates. These reflect a proposed revenue requirement change of $75.9 million.

Q. As a result of these changes, what is the net impact on customers?

A. Including the effects of all tariff riders and the elimination of Schedule 94, PPL Exhibit 1211 shows this results in an overall average net increase of 3.5 percent.

Q. Please describe PPL Exhibit 1213.

A. PPL Exhibit 1213 provides, for illustrative purposes, an analysis of Staff's proposed rate mitigation adjustment and rate spread presented in the Surrebuttal testimony of Mr. Jack Breen. I discuss this more fully later in my testimony.

Q. How are the Klamath River Basin customers presented in this exhibit?

A. The Klamath River Basin customers are shown remaining on their current contract rates for both present and proposed revenues. In the Company's direct case and my rebuttal testimony, the Klamath River Basin customers were included under Schedule 41 standard tariff rates for both present and proposed revenues.

Q. Please explain this change.

A. On June 30, 2005, in a Prehearing Conference Memorandum issued in this docket, the ALJ indicated,

> The parties agreed that the irrigation rate for customers within the Klamath River Basin need not be completed prior to September 12, 2005—the suspension date for the general rate proceeding, but should be resolved prior to April 6, 2006—the expiration date of the 1956 on-project contract. To accomplish this, the parties suggest that the Commission use the current contract rates, set forth in Schedule 33, as interim rates for these irrigation customers when setting PacifiCorp's revenue requirement in the general rate proceeding. The parties further agreed that, once a Commission decision is made regarding the rates for the Klamath River Basin irrigators, PacifiCorp would spread any revenue requirement impact

of that decision to other customer classes through an adjustment to its rate spread/rate design.

PPL Exhibit 1210, PPL Exhibit 1211, and PPL Exhibit 1212 contain this revision setting the Klamath River Basin customers on their contract rates for both present and proposed revenues in this case. Upon resolution of the Klamath River Basin customer issue, any adjustment to Klamath River Basin customer costs and revenues would be offset and applied to all customers through an adjustment schedule in order to maintain the ordered test period revenue requirement.

Billing Period Variability

Q. In light of the surrebuttal testimony of CUB and Staff, what is the Company's position concerning the issue of bill proration and billing period variability?

A. The Company believes that both proposals—i.e., the proposal to prorate bills with meter read cycles less than 26 days and greater than 34 days (the 26-34 day proration proposal) and CUB's alternative proposal (the All Bills proration proposal)--have different advantages and disadvantages. Based on additional review, if the Commission should choose to adopt residential bill proration to address meter read cycle variation, the Company supports CUB's proposal to prorate all residential bills.

Q. Please explain the 26-34 day proration proposal.

A. In my rebuttal testimony, the Company preferred to prorate all bills with meter read cycles less than 26 days and greater than 34 days (the 26-34 day proration proposal). We indicated that this method would address the billing cycle issue simply, with minimal manipulation of billing data. Bills within the normal meter read cycle would not be affected by this change.

Mr. Breen's testimony representing Staff indicates that Staff is in agreement with the Company's proposal to prorate bills shorter than 26 days and greater than 34 days, but Staff does not support the Company's revenue shortfall adjustment.

Q. **Do you agree with Staff's position that the revenue shortfall attributable to prorating bills less than 26 days and more than 34 days presented in your rebuttal testimony should not be recovered by the Company?**

A. No. A shortfall would occur if the 26-34 day proration proposal were implemented using 30 day proration. Absent this proration proposal, a shortfall would not occur.

Q. **Do you have additional information that could help address this issue?**

A. Yes, the Company has done additional research on this. One reason shortfalls occurred in the proration analyses presented in my rebuttal testimony was that all proration was computed based on a 30 day basis. Historically, the Company has prorated a small number of bills, such as opening and closing bills, on a 30 day basis. This has worked well and as a result the Company's proration billing logic has been written based on a 30 day proration period. Thirty day proration created a shortfall, however, in the earlier proration analyses presented in my rebuttal testimony because the total proration amounts did not total to a full year: 12 months of 30 days proration equals only 360 days. To limit a revenue shortfall, proration should occur on a 30.42 day basis (365 days/12 months = 30.42 days).

Q. Could the Company prorate bills on a 30.42 day basis?

A. We could not prorate bills on a 30.42 day basis with our existing proration logic. Extensive modification to the existing proration logic would be necessary in order to prorate bills based on 30.42 days. The same result can be achieved mathematically, however, by setting the first residential energy block to terminate at 493 kWh per month for non-prorated bills (30/30.42*500 kWh) and the second energy block at 986 kWh. Although this would limit the shortfall, for non-prorated customers under the 26-34 day proration proposal, the residential energy blocks would be different from the tariffed blocks. This would create the type of customer confusion we hoped this option would avoid.

Q. **Please explain the All Bills proration proposal.**

A. The underlying logic of the All Bills proration proposal prorates every residential bill based on the number of billing days in the meter read cycle and implements, in essence, daily blocks for all bills (493 kWh for each thirty days). This assures a more equitable treatment of allocating kWh blocks; however, it does produce kWh block variability based on the number of days in the billing cycle. As an example, the 0-500 kWh block would equal 0-493 kWh for a 30 day bill, and 0-526 kWh for a 32 day bill. These correspond to Mr. Jenks' proposed daily blocks where the first block would equal 16.44 kWh/day (16.44 x 30 = 493 kWh).

Q. In its surrebuttal testimony, CUB indicates that the All Bills proration proposal is a "no brainer". Please comment.

A. Clearly, the All Bills proration adjustment is not a "no brainer", but it does resolve CUB's equity issue and it handles the limitations discussed above given existing proration logic should the Commission choose to implement proration to address meter cycle variability. However, such a method will add complexity to all of the 460,000 residential bills rendered each month. If all residential bills are prorated, the thresholds for the three rate blocks for all residential customers' bills will vary depending on the number of days in the billing cycle. This may lead to customer confusion.

On the other hand, under the 26-34 day proration proposal, only monthly billing cycle outliers will be adjusted, and the existing equity issue will not be resolved.

Based on this review, if the Commission should choose to adopt residential bill proration, the Company believes the All Bills proration proposal is the preferred approach going forward for residential customers.

Q. Could the Company implement either the 26-34 day proration proposal or the All Bills proration proposal discussed above for residential customers with rates effective on and after September 12, 2005?

A. Yes. The Company could implement either proposal described above using the existing proration logic currently in place in the Company's billing system.

Rate Spread and Rate Mitigation Adjustment

Q. Does the Company offer any changes to its proposed rebuttal rate spread methodology?

A. After adjusting for the revenue requirement change and other assumptions, the Company continues to support the rate spread proposal presented in my rebuttal testimony. PPL Exhibit 1210 shows the revised rate spread excluding the effects of the elimination of Schedule 94, adjusted for the revised revenue requirement, and including the assumption that the Klamath River Basin customers are billed at contract rates. PPL Exhibit 1211 shows the revised rate spread including the effects of the elimination of Schedule 94, adjusted for the revised revenue requirement, and including the assumption that the Klamath River Basin customers are billed at contract rates. The method employed in PPL Exhibits 1210 and 1211 is the same method proposed in my rebuttal testimony. In addition to providing a reasonable outcome, this approach results in the elimination of the RMA for residential and Schedule 47/48T customers as the Company first proposed in its direct case.

Q. In its surrebuttal testimony, Staff presents a proposal that eliminates net rate reductions and, depending on the revenue requirement, would implement up to a three percent rate increase for any customer class below cost of service when the 1.5 times the net increase guideline should produce an overall increase less than three percent. Does the Company support Staff's proposal?

A. PPL Exhibit 1213 provides an analysis of Staff's proposal for illustrative purposes. Based on our analysis, the Company believes Staff's proposal is a reasonable alternative if the Commission should choose to eliminate net rate decreases in the face of an overall increase. Based on our analysis, the effect of this proposal would also result in a continuation of the RMA for residential and Schedule 47/48 customers.

In order to provide cost of service-based differentiation, our analysis of

Staff's proposal implements 1.5 times the net overall increase (5.2%) for any rate schedule requiring a base rate increase greater than 10 percent. Schedules requiring an increase between one and 10 percent to base rates receive approximately the average net increase (3.5%). No customer class receives a net decrease. Based on this analysis, an RMA would continue for residential and Schedule 47/48 customers.

The Company believes a proposal such as Staff's is a reasonable alternative if the Commission should choose to eliminate net rate decreases in the face of an overall increase and should also choose to allow the RMA to continue for residential and Schedule 47/48 customers.

Q. Does this conclude your sursurrebuttal testimony?

A. Yes it does.

1210 Griffith Exhibit

Case UE-170
PPL Exhibit 1210
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of William R. Griffith

Estimated Effect of Proposed Price Change
Excluding the Effects of the Elimination of Schedule 94

July 2005

Table 1210-1
EXCLUDING THE EFFECTS OF THE ELIMINATION OF SCHEDULE 94
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)	%	Line No.
	(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	($17,523)	$371,788	$417,336	($8,329)	$409,007	$28,025	7.2%	$37,219	10.0%	1
2	**Total Residential**			460,491	5,079,177	$389,311	($17,523)	$371,788	$417,336	($8,329)	$409,007	$28,025	7.2%	$37,219	10.0%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23/36	23	68,716	1,111,483	$74,368	$223	$74,591	$90,891	($5,913)	$84,978	$16,523	22.2%	$10,387	13.9%	3
4	Gen. Svc. 31 - 200 kW	28/36	28	9,809	2,110,361	$117,664	$867	$118,531	$117,841	$2,556	$120,397	$177	0.2%	$1,866	1.6%	4
5	Gen. Svc. 201 - 999 kW	30/36	30	1,017	1,436,166	$70,762	$1,019	$71,781	$75,889	($259)	$75,630	$5,127	7.3%	$3,849	5.4%	5
6	Large General Service >= 1,000 kW	48	48	231	3,388,352	$126,742	$984	$127,726	$149,980	($4,437)	$145,543	$23,238	18.3%	$17,817	14.0%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	7	230,294	$10,889	$50	$10,939	$12,494	($319)	$12,175	$1,605	14.7%	$1,236	11.3%	7
8	Agricultural Pumping Service	41	41	6,229	119,204	$10,351	($2,427)	$7,924	$11,946	($2,917)	$9,029	$1,595	15.4%	$1,105	13.9%	8
9	Agricultural Pumping - Other	33	33	2,110	90,609	$604	$0	$604	$604	$0	$604	$0	0.0%	$0	0.0%	9
10	**Total Commercial & Industrial**			88,119	8,486,469	$411,380	$716	$412,096	$459,645	($11,289)	$448,356	$48,265	11.7%	$36,260	8.8%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	7,933	12,626	$1,584	$5	$1,589	$1,503	$102	$1,605	($81)	-5.1%	$16	1.0%	11
12	Street Lighting Service	50	50	316	11,391	$1,251	$3	$1,254	$1,186	$81	$1,267	($65)	-5.2%	$13	1.0%	12
13	Street Lighting Service HPS	51	51	667	16,349	$2,883	$15	$2,898	$2,734	$193	$2,927	($149)	-5.2%	$29	1.0%	13
14	Street Lighting Service	52	52	111	1,998	$232	$0	$232	$220	$14	$234	($12)	-5.2%	$2	0.9%	14
15	Street Lighting Service	53	53	229	8,400	$538	$1	$539	$511	$34	$545	($27)	-5.0%	$6	1.1%	15
16	Recreational Field Lighting	54	54	91	760	$65	($1)	$64	$62	$2	$64	($3)	-4.6%	$0	0.0%	16
17	**Total Public Street Lighting**			9,347	51,524	$6,553	$23	$6,576	$6,216	$426	$6,642	($337)	-5.1%	$66	1.0%	17
18	**Total Sales to Ultimate Consumers**			557,957	13,617,170	$807,244	($16,784)	$790,460	$883,197	($19,192)	$864,005	$75,953	9.4%	$73,545	9.3%	18
19	**Employee Discount**				20,911	($397)	$18	($379)	($426)	$9	($417)	($29)		($38)		19
20	**Total Sales with Employee Discount**			557,957	13,617,170	$806,847	($16,766)	$790,081	$882,771	($19,183)	$863,588	$75,924	9.4%	$73,507	9.3%	20
21	AGA Revenue					$1,404		$1,404	$1,404		$1,404	$0		$0		21
22	**Total Sales with Employee Discount and AGA**			557,957	13,617,170	$808,251	($16,766)	$791,485	$884,175	($19,183)	$864,992	$75,924	9.4%	$73,507	9.3%	22

[1] Excludes effects of the BPA Energy Discount (Schedule 98), Low Income Bill Payment Assistance Charge (Schedule 91), Public Purpose Charge (Schedule 290) and Deferred Accounting Adjustment (Schedule 94).
[2] Includes new Sch 95 Miscellaneous Deferred Credit $1.8 million.

Table 1210-2
PACIFIC POWER & LIGHT COMPANY
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2006

Line No.	Description	Pre Sch No.	Pro Sch No.	Y2K 96 ($000)	CTL 97 ($000)	T MTN 198 ($000)	291 292 293 ($000)	RMA 299 ($000) PRE	RMA 299 ($000) PRO	Mis Credit 95 ($000)	Total ($000) PRE	Total ($000) PRO
	Residential											
1	Residential	4	4	$102	($9,701)	$1,016	$914	($9,854)	$0	($660)	($17,523)	($8,329)
2	**Total Residential**											
	Commercial & Industrial											
3	Gen. Svc. < 31 kW	23/36	23	$23	($2,123)	$222	$667	$1,434	($4,557)	($145)	$223	($5,913)
4	Gen. Svc. 31 - 200 kW	28/36	28	$43	($4,030)	$422	$1,140	$3,292	$5,255	($274)	$867	$2,556
5	Gen. Svc. 201 - 999 kW	30/36	30	$29	($2,743)	$286	$776	$2,671	$1,580	($187)	$1,019	($259)
6	Large General Service >= 1,000 kW	48	48	$67	($6,472)	$579	$1,830	$4,980	$0	($441)	$984	($4,437)
7	Partial Req. Svc. >= 1,000 kW	47	47	$5	($440)	$22	$124	$339	$0	($30)	$50	($319)
8	Agricultural Pumping Service	41	41	$2	($228)	$23	$72	($2,296)	($2,771)	($15)	($2,427)	($2,917)
9	Agricultural Pumping - Other	33	33	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	**Total Commercial & Industrial**			$169	($16,036)	$1,554	$4,609	$10,420	($493)	($1,092)	$716	($11,289)
	Lighting											
11	Outdoor Area Lighting Service	15	15	$0	($24)	$1	$7	$21	$119	($1)	$5	$102
12	Street Lighting Service	50	50	$0	($22)	$1	$7	$17	$96	($1)	$3	$81
13	Street Lighting Service HPS	51	51	$0	($31)	$3	$10	$33	$213	($2)	$15	$193
14	Street Lighting Service	52	52	$0	($4)	$0	$1	$3	$17	$0	$0	$14
15	Street Lighting Service	53	53	$0	($16)	$1	$5	$11	$45	($1)	$1	$34
16	Recreational Field Lighting	54	54	$0	($1)	$0	$0	$0	$3	$0	($1)	$2
17	**Total Public Street Lighting**			$0	($98)	$6	$30	$85	$493	($5)	$23	$426
18	**Total**			$271	($25,835)	$2,576	$5,553	$651	$0	($1,757)	($16,784)	($19,192)
19	**Employee Discount**			$0	$10	($1)	($1)	$10	$0	$1	$18	$9
20	**Total Sales with Employee Discount**			$271	($25,825)	$2,575	$5,552	$661	$0	($1,756)	($16,766)	($19,183)

Table 1210-3
PACIFIC POWER & LIGHT COMPANY
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2006

Line No.	Description	Pre Sch No.	Pro Sch No.	Y2K 96 ¢/kWh	CTL 97 ¢/kWh	T MTN 198S ¢/kWh	T MTN 198P ¢/kWh	T MTN 198T ¢/kWh	291 292 293 ¢/kWh	RMA 299 ¢/kWh PRE	RMA 299 ¢/kWh PRO	Mis Credit 95 ¢/kWh
	Residential											
1	Residential	4	4	0.002	(0.191)	0.020			0.018	(0.194)	0.000	(0.013)
	Commercial & Industrial											
2	Gen. Svc. < 31 kW	23	23	0.002	(0.191)	0.020	0.019		0.060	0.129	(0.410)	(0.013)
3	Gen. Svc. 31 - 200 kW	28	28	0.002	(0.191)	0.020	0.019		0.054	0.156	0.249	(0.013)
4	Gen. Svc. 201 - 999 kW	30	30	0.002	(0.191)	0.020	0.019		0.054	0.186	0.110	(0.013)
5	Large General Service >= 1,000 kW	48	48	0.002	(0.191)	0.018	0.017	0.016	0.054	0.147	0.000	(0.013)
6	Partial Req. Svc. >= 1,000 kW	47	47	0.002	(0.191)	0.017	0.016		0.054	0.147	0.000	(0.013)
7	Agricultural Pumping Service	41	41	0.002	(0.191)	0.019	0.018		0.060	(1.926)	(2.325)	(0.013)
8	Agricultural Pumping - Other	33	33	0.000	0.000	0.000	0.000		0.000	0.000	0.000	0.000
	Lighting											
9	Outdoor Area Lighting Service	15	15	0.002	(0.191)	0.012			0.060	0.160	0.940	(0.013)
10	Street Lighting Service	50	50	0.002	(0.191)	0.011			0.060	0.145	0.840	(0.013)
11	Street Lighting Service HPS	51	51	0.002	(0.191)	0.017			0.060	0.199	1.300	(0.013)
12	Street Lighting Service	52	52	0.002	(0.191)	0.013			0.060	0.150	0.870	(0.013)
13	Street Lighting Service	53	53	0.002	(0.191)	0.006			0.060	0.130	0.530	(0.013)
14	Recreational Field Lighting	54	54	0.002	(0.191)	0.010			0.060	0.060	0.460	(0.013)

Case UE-170
PPL Exhibit 1211
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of William R. Griffith

Estimated Effect of Proposed Price Change
Including the Effects of the Elimination of Schedule 94

July 2005

Table 1211-1
INCLUDING THE EFFECTS OF THE ELIMINATION OF SCHEDULE 94
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

Line No.	Description	Pre Sch No.	Pro Sch No.	No. of Cust	MWh	Present Revenues ($000) Base Rates	Present Revenues ($000) Adders[1]	Present Revenues ($000) Net Rates	Proposed Revenues ($000) Base Rates	Proposed Revenues ($000) Adders[1,2]	Proposed Revenues ($000) Net Rates	Change Base Rates ($000)	Change Base Rates %	Change Net Rates ($000)	Change Net Rates %	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) (6) + (7)	(9)	(10)	(11) (9) + (10)	(12) (9) - (6)	(13) (12)/(6)	(14) (11) - (8)	(15) (14)/(8)	
	Residential															
1	Residential	4	4	460,491	5,079,177	$389,311	($559)	$388,752	$417,336	($8,329)	$409,007	$28,025	7.2%	$20,255	5.2%	1
2	**Total Residential**			460,491	5,079,177	$389,311	($559)	$388,752	$417,336	($8,329)	$409,007	$28,025	7.2%	$20,255	5.2%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23/36	23	68,716	1,111,483	$74,368	$3,935	$78,303	$90,891	($5,913)	$84,978	$16,523	22.2%	$6,675	8.5%	3
4	Gen. Svc. 31 - 200 kW	28/36	28	9,809	2,110,361	$117,664	$7,912	$125,576	$117,841	$2,556	$120,397	$177	0.2%	($5,179)	-4.1%	4
5	Gen. Svc. 201 - 999 kW	30/36	30	1,017	1,436,166	$70,762	$5,802	$76,564	$75,889	($259)	$75,630	$5,127	7.3%	($934)	-1.2%	5
6	Large General Service >= 1,000 kW	48	48	231	3,388,352	$126,742	$11,873	$138,615	$149,980	($4,437)	$145,543	$23,238	18.3%	$6,928	5.0%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	7	230,294	$10,889	$488	$11,377	$12,494	($319)	$12,175	$1,605	14.7%	$798	7.0%	7
8	Agricultural Pumping Service	41	41	6,229	119,204	$10,351	($2,029)	$8,322	$11,946	($2,917)	$9,029	$1,595	15.4%	$707	8.5%	8
9	Agricultural Pumping - Other	33	33	2,110	90,609	$604	$0	$604	$604	$0	$604	$0	0.0%	$0	0.0%	9
10	**Total Commercial & Industrial**			88,119	8,486,469	$411,380	$27,981	$439,361	$459,645	($11,289)	$448,356	$48,265	11.7%	$8,995	2.1%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	7,933	12,626	$1,584	$47	$1,631	$1,503	$102	$1,605	($81)	-5.1%	($26)	-1.6%	11
12	Street Lighting Service	50	50	316	11,391	$1,251	$41	$1,292	$1,186	$81	$1,267	($65)	-5.2%	($25)	-1.9%	12
13	Street Lighting Service HPS	51	51	667	16,349	$2,883	$70	$2,953	$2,734	$193	$2,927	($149)	-5.2%	($26)	-0.9%	13
14	Street Lighting Service	52	52	111	1,998	$232	$7	$239	$220	$14	$234	($12)	-5.2%	($5)	-2.1%	14
15	Street Lighting Service	53	53	229	8,400	$538	$29	$567	$511	$34	$545	($27)	-5.0%	($22)	-3.9%	15
16	Recreational Field Lighting	54	54	91	760	$65	$2	$67	$62	$2	$64	($3)	-4.6%	($3)	-4.5%	16
17	**Total Public Street Lighting**			9,347	51,524	$6,553	$196	$6,749	$6,216	$426	$6,642	($337)	-5.1%	($107)	-1.6%	17
18	**Total Sales to Ultimate Consumers**			557,957	13,617,170	$807,244	$27,618	$834,862	$883,197	($19,192)	$864,005	$75,953	9.4%	$29,143	3.5%	18
19	**Employee Discount**				20,911	($397)	$1	($396)	($426)	$9	($417)	($29)		($21)		19
20	**Total Sales with Employee Discount**			557,957	13,617,170	$806,847	$27,619	$834,466	$882,771	($19,183)	$863,588	$75,924	9.4%	$29,122	3.5%	20
21	AGA Revenue					$1,404		$1,404	$1,404		$1,404	$0		$0		21
22	**Total Sales with Employee Discount and AGA**			557,957	13,617,170	$808,251	$27,619	$835,870	$884,175	($19,183)	$864,992	$75,924	9.4%	$29,122	3.5%	22

[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] Excludes effects of Deferred Accounting Adjustment (Schedule 94) and includes new Sch 95 Miscellaneous Deferred Credit $1.8 million.

Table 1211-2
PACIFIC POWER & LIGHT COMPANY
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2006

Line No.	Description	Pre Sch No.	Pro Sch No.	D ACNT 94 ($000)	Y2K 96 ($000)	CTL 97 ($000)	T MTN 198 ($000)	291 292 293 ($000)	RMA 299 ($000) PRE	RMA 299 ($000) PRO	Mis Credit 95 ($000)	Total ($000) PRE	Total ($000) PRO
	Residential												
1	Residential	4	4	$16,964	$102	($9,701)	$1.016	$914	($9,854)	$0	($660)	($559)	($8,329)
2	**Total Residential**												
	Commercial & Industrial												
3	Gen. Svc. < 31 kW	23/36	23	$3,712	$23	($2,123)	$222	$667	$1,434	($4,557)	($145)	$3,935	($5,913)
4	Gen. Svc. 31 - 200 kW	28/36	28	$7,045	$43	($4,030)	$422	$1,140	$3,292	$5,255	($274)	$7,912	$2,556
5	Gen. Svc. 201 - 999 kW	30/36	30	$4,783	$29	($2,743)	$286	$776	$2,671	$1,580	($187)	$5,802	($259)
6	Large General Service >= 1,000 kW	48	48	$10,889	$67	($6,472)	$579	$1,830	$4,980	$0	($441)	$11,873	($4,437)
7	Partial Req. Svc. >= 1,000 kW	47	47	$438	$5	($440)	$22	$124	$339	$0	($30)	$488	($319)
8	Agricultural Pumping Service	41	41	$398	$2	($228)	$23	$72	($2,296)	($2,771)	($15)	($2,029)	($2,917)
9	Agricultural Pumping - Other	33	33	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	**Total Commercial & Industrial**			$27,265	$169	($16,036)	$1,554	$4,609	$10,420	($493)	($1,092)	$27,981	($11,289)
	Lighting												
11	Outdoor Area Lighting Service	15	15	$42	$0	($24)	$1	$7	$21	$119	($1)	$47	$102
12	Street Lighting Service	50	50	$38	$0	($22)	$1	$7	$17	$96	($1)	$41	$81
13	Street Lighting Service HPS	51	51	$55	$0	($31)	$3	$10	$33	$213	($2)	$70	$193
14	Street Lighting Service	52	52	$7	$0	($4)	$0	$1	$3	$17	$0	$7	$14
15	Street Lighting Service	53	53	$28	$0	($16)	$1	$5	$11	$45	($1)	$29	$34
16	Recreational Field Lighting	54	54	$3	$0	($1)	$0	$0	$0	$3	$0	$2	$2
17	**Total Public Street Lighting**			$173	$0	($98)	$6	$30	$85	$493	($5)	$196	$426
18	**Total**			$44,402	$271	($25,835)	$2,576	$5,553	$651	$0	($1,757)	$27,618	($19,192)
19	**Employee Discount**			($17)	$0	$10	($1)	($1)	$10	$0	$1	$1	$9
20	**Total Sales with Employee Discount**			$44,385	$271	($25,825)	$2.575	$5,552	$661	$0	($1,756)	$27,619	($19,183)

Table 1211-3
PACIFIC POWER & LIGHT COMPANY
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2006

Line No.	Description	Pre Sch No.	Pro Sch No.	D ACNT 94S ¢/kWh	D ACNT 94P ¢/kWh	D ACNT 94T ¢/kWh	Y2K 96 ¢/kWh	CTL 97 ¢/kWh	T MTN 198S ¢/kWh	T MTN 198P ¢/kWh	T MTN 198T ¢/kWh	291 292 293 ¢/kWh	RMA 299 ¢/kWh PRE	RMA 299 ¢/kWh PRO	Mis Credit 95 ¢/kWh
	Residential														
1	Residential	4	4	0.334			0.002	(0.191)	0.020			0.018	(0.194)	0.000	(0.013)
	Commercial & Industrial														
2	Gen. Svc. < 31 kW	23	23	0.334	0.320		0.002	(0.191)	0.020	0.019		0.060	0.129	(0.410)	(0.013)
3	Gen. Svc. 31 - 200 kW	28	28	0.334	0.320		0.002	(0.191)	0.020	0.019		0.054	0.156	0.249	(0.013)
4	Gen. Svc. 201 - 999 kW	30	30	0.334	0.320		0.002	(0.191)	0.020	0.019		0.054	0.186	0.110	(0.013)
5	Large General Service >= 1,000 kW	48	48	0.334	0.320	0.307	0.002	(0.191)	0.018	0.017	0.016	0.054	0.147	0.000	(0.013)
6	Partial Req. Svc. >= 1,000 kW	47	47	0.334	0.320		0.002	(0.191)	0.017	0.016		0.054	0.147	0.000	(0.013)
7	Agricultural Pumping Service	41	41	0.334	0.320		0.002	(0.191)	0.019	0.018		0.060	(1.926)	(2.325)	(0.013)
8	Agricultural Pumping - Other	33	33	0.000	0.000		0.000	0.000	0.000	0.000		0.000	0.000	0.000	0.000
	Lighting														
9	Outdoor Area Lighting Service	15	15	0.334			0.002	(0.191)	0.012			0.060	0.160	0.940	(0.013)
10	Street Lighting Service	50	50	0.334			0.002	(0.191)	0.011			0.060	0.145	0.840	(0.013)
11	Street Lighting Service HPS	51	51	0.334			0.002	(0.191)	0.017			0.060	0.199	1.300	(0.013)
12	Street Lighting Service	52	52	0.334			0.002	(0.191)	0.013			0.060	0.150	0.870	(0.013)
13	Street Lighting Service	53	53	0.334			0.002	(0.191)	0.006			0.060	0.130	0.530	(0.013)
14	Recreational Field Lighting	54	54	0.334			0.002	(0.191)	0.010			0.060	0.060	0.460	(0.013)

1212 Griffith Exhibit

Case UE-170
PPL Exhibit 1212
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of William R. Griffith

Billing Determinants

July 2005

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. 4								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	5,079,177,218	kWh	0.472	¢	$23,973,716	0.447	¢	$22,703,922
Distribution Charge								
Basic Charge, per month	5,525,896	bill	$7.00		$38,681,272	$8.00		$44,207,168
Three Phase Demand Charge, per kW demand	17,729	kW	$2.20		$39,004	$2.20		$39,004
Three Phase Minimum Demand Charge, per month	1,597	bill	$3.80		$6,069	$3.80		$6,069
Distribution Energy Charge, per kWh	5,079,177,218	kWh	3.445	¢	$174,977,655	3.104	¢	$157,657,661
Energy Charge (Sch 200)								
<=500 kWh	2,333,709,553	kWh	2.512	¢	$58,622,784	3.193	¢	$74,515,346
'500-1,000 kWh	1,455,499,315	kWh	3.026	¢	$44,043,409	3.846	¢	$55,978,504
>1,000 kWh	1,289,968,350	kWh	3.796	¢	$48,967,199	4.824	¢	$62,228,073
Total Energy kWh	5,079,177,218	kWh			$151,633,392			$192,721,923
Total	5,079,177,218				$389,311,108			$417,335,747
						Change		$28,024,639
Schedule No. 4 - Employee Discount								
Residential Service								
Transmission & Ancillary Services Charge								
per kWh	20,911,318	kWh	0.472	¢	$98,701	0.447	¢	$93,474
Distribution Charge								
Basic Charge, per month	17,653	bill	$7.00		$123,571	$8.00		$141,224
Three Phase Demand Charge, per kW demand	81	kW	$2.20		$178	$2.20		$178
Three Phase Minimum Demand Charge, per month	13	bill	$3.80		$49	$3.80		$49
Distribution Energy Charge, per kWh	20,911,318	kWh	3.445	¢	$720,395	3.104	¢	$649,087
Energy Charge (Sch 200)								
<=500 kWh	8,021,936	kWh	2.512	¢	$201,511	3.193	¢	$256,140
'500-1,000 kWh	5,973,311	kWh	3.026	¢	$180,752	3.846	¢	$229,734
>1,000 kWh	6,916,071	kWh	3.796	¢	$262,534	4.824	¢	$333,631
Total Energy kWh	20,911,318	kWh			$644,797			$819,505
Subtotal	20,911,318				$1,587,691			$1,703,517
Total Employee Discount					($396,923)			($425,879)

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. 23/723 - Composite General Service (Secondary)								
Transmission & Ancillary Services Charge								
per kWh	1,110,753,184	kWh	0.513	¢	$5,698,164	0.477	¢	$5,298,293
Distribution Charge								
Basic Charge								
Single Phase, per month	661,920	bill	$10.20		$6,751,584	$16.55		$10,954,776
Three Phase, per month	162,319	bill	$15.25		$2,475,365	$24.75		$4,017,395
Load Size Charge								
≤ 15 kW	995,904	kW	No Charge			No Charge		
per kW for all kW in excess of 15 kW	576,819	kW	$0.70		$403,773	$1.15		$663,342
Demand Charge, the first 15 kW of demand	683,056	kW	No Charge			No Charge		
Demand Charge, per kW for all kW in excess of 15 kW	286,028	kW	$2.38		$680,747	$3.86		$1,104,068
Reactive Power Charge, per kvar	31,056	kvar	65.00	¢	$20,186	65.00	¢	$20,186
Distribution Energy Charge, per kWh	1,110,753,184	kWh	1.420	¢	$15,772,695	2.309	¢	$25,647,291
Energy Charge (Sch 200)								
1st 3,000 kWh, per kWh	874,528,677	kWh	4.069	¢	$35,584,572	4.127	¢	$36,091,798
All additional kWh, per kWh	236,224,507	kWh	2.935	¢	$6,933,189	2.977	¢	$7,032,404
Total	1,110,753,184				$74,320,275			$90,829,553
						Change		$16,509,278

Schedule	Forecast 1/06 - 12/06 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Schedule No. 23/723 - Composite General Service (Primary)								
Transmission & Ancillary Services Charge								
per kWh	727,970	kWh	0.472	¢	$3,436	0.464	¢	$3,378
Distribution Charge								
Basic Charge								
Single Phase, per month	179	bill	$9.90		$1,772	$16.55		$2,962
Three Phase, per month	165	bill	$14.80		$2,442	$24.75		$4,084
Load Size Charge								
≤ 15 kW	1,370	kW	No Charge			No Charge		
per kW for all kW in excess of 15 kW	2,356	kW	$0.70		$1,649	$1.15		$2,709
Demand Charge, the first 15 kW of demand	842	kW	No Charge			No Charge		
Demand Charge, per kW for all kW in excess of 15 kW	363	kW	$2.31		$839	$3.76		$1,365
Reactive Power Charge, per kvar	2,922	kvar	60.00	¢	$1,753	60.00	¢	$1,753
Distribution Energy Charge, per kWh	727,970	kWh	0.924	¢	$6,726	2.245	¢	$16,343
Energy Charge (Sch 200)								
1st 3,000 kWh, per kWh	590,747	kWh	4.325	¢	$25,550	4.013	¢	$23,707
All additional kWh, per kWh	137,223	kWh	3.121	¢	$4,283	2.895	¢	$3,973
Total	727,970				$48,450			$60,274
						Change		$11,824

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. 28/728 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge								
per kW, (minimum 31 kW)	6,800,861	kW	$1.74		$11,833,498			
per kW, (minimum 15 kW)	6,592,953	kW				$1.34		$8,834,557
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	55,933	bill	$16.00		$894,928	$14.00		$783,062
Load Size 51-100 kW, per month	37,134	bill	$28.00		$1,039,752	$25.00		$928,350
Load Size 101-300 kW, per month	23,648	bill	$65.00		$1,537,120	$57.00		$1,347,936
Load Size > 300 kW, per month	281	bill	$93.00		$26,133	$82.00		$23,042
Load Size Charge								
≤ 50 kW	1,897,563	kW	$0.94		$1,783,709	$0.85		$1,612,929
51-100 kW, per kW	2,446,182	kW	$0.77		$1,883,560	$0.70		$1,712,327
101-300 kW, per kW	3,419,856	kW	$0.41		$1,402,141	$0.35		$1,196,950
>300 kW, per kW	120,291	kW	$0.31		$37,290	$0.25		$30,073
Demand Charge, per kW (minimum 31 kW)	6,800,861	kW	$2.68		$18,226,307			
Demand Charge, per kW (minimum 15 kW)	6,592,953	kW				$2.44		$16,086,805
Reactive Power Charge, per kvar	519,989	kvar	65.00	¢	$337,993	65.00	¢	$337,993
Distribution Energy Charge, per kWh	2,087,230,152	kWh	0.330	¢	$6,887,860	0.286	¢	$5,969,478
Energy Charge (Sch 200)								
1st 20,000 kWh, per kWh	1,493,782,683	kWh	3.408	¢	$50,908,114	3.753	¢	$56,061,664
All additional kWh, per kWh	593,447,469	kWh	3.309	¢	$19,637,177	3.647	¢	$21,643,029
Total	2,087,230,152				$116,435,582			$116,568,195
						Change		$132,613

Schedule	Forecast 1/06 - 12/06 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Schedule No. 28/728 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge								
per kW, (minimum 31 kW)	70,337	kW	$2.00		$140,674			
per kW, (minimum 15 kW)	69,561	kW				$1.28		$89,038
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	135	bill	$17.00		$2,295	$19.00		$2,565
Load Size 51-100 kW, per month	134	bill	$30.00		$4,020	$33.00		$4,422
Load Size 101-300 kW, per month	345	bill	$70.00		$24,150	$76.00		$26,220
Load Size > 300 kW, per month	34	bill	$100.00		$3,400	$109.00		$3,706
Load Size Charge								
≤ 50 kW	2,227	kW	$0.95		$2,116	$1.05		$2,338
51-100 kW, per kW	10,211	kW	$0.78		$7,965	$0.85		$8,679
101-300 kW, per kW	58,646	kW	$0.41		$24,045	$0.45		$26,391
>300 kW, per kW	16,973	kW	$0.31		$5,262	$0.35		$5,941
Demand Charge, per kW (minimum 31 kW)	70,337	kW	$3.00		$211,011			
Demand Charge, per kW (minimum 15 kW)	69,561	kW				$3.31		$230,247
Reactive Power Charge, per kvar	14,775	kvar	60.00	¢	$8,865	60.00	¢	$8,865
Distribution Energy Charge, per kWh	22,353,219	kWh	0.050	¢	$11,177	0.058	¢	$12,965
Energy Charge (Sch 200)								
1st 20,000 kWh, per kWh	11,025,982	kWh	3.292	¢	$362,975	3.638	¢	$401,125
All additional kWh, per kWh	11,327,237	kWh	3.196	¢	$362,018	3.532	¢	$400,078
Total	22,353,219				$1,169,973			$1,222,580
						Change		$52,607

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. 30/730 - Composite								
Large General Service - (Secondary)								
Transmission & Ancillary Services Charge per kW	3,723,635	kW	$1.67		$6,218,470	$1.54		$5,734,398
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	96	bill	$320.00		$30,624	$319.00		$30,528
Load Size 201-300 kW, per month	3,659	bill	$100.00		$365,928	$100.00		$365,928
Load Size > 300 kW, per month	7,726	bill	$260.00		$2,008,751	$259.00		$2,001,025
Load Size Charge								
≤ 200 kW	7,126	kW	$0.00		$0	$0.00		$0
201-300 kW, per kW	841,598	kW	$1.10		$925,758	$1.10		$925,758
>300 kW, per kW	3,457,167	kW	$0.55		$1,901,442	$0.55		$1,901,442
Demand Charge, per kW	3,723,635	kW	$2.51		$9,346,324	$2.50		$9,309,088
Reactive Power Charge, per kvar	794,996	kvar	65.00	¢	$516,747	65.00	¢	$516,747
Energy Charge (Sch 200)								
1st 20,000 kWh, per kWh	200,307,204	kWh	3.353	¢	$6,716,301	4.245	¢	$8,503,041
All additional kWh, per kWh	1,140,844,656	kWh	3.334	¢	$38,035,761	3.647	¢	$41,606,605
Total	1,341,151,860				$66,066,106			$70,894,560
						Change		$4,828,454
Schedule No. 30/730 - Composite								
Large General Service - (Primary)								
Transmission & Ancillary Services Charge per kW	268,014	kW	$1.60		$428,822	$1.42		$380,580
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	2	bill	$310.00		$766	$312.00		$771.00
Load Size 201-300 kW, per month	124	bill	$100.00		$12,373	$101.00		$12,497.00
Load Size > 300 kW, per month	549	bill	$260.00		$142,703	$262.00		$143,800.00
Load Size Charge								
≤ 200 kW	84	kW	$0.00		$0	$0.00		$0
201-300 kW, per kW	27,886	kW	$1.05		$29,280	$1.05		$29,280
>300 kW, per kW	294,332	kW	$0.55		$161,883	$0.55		$161,883
Demand Charge, per kW	268,014	kW	$2.46		$659,314	$2.48		$664,675
Reactive Power Charge, per kvar	35,568	kvar	60.00	¢	$21,341	60.00	¢	$21,341
Energy Charge (Sch 200)								
1st 20,000 kWh, per kWh	11,668,827	kWh	3.233	¢	$377,253	4.303	¢	$502,110
All additional kWh, per kWh	79,855,727	kWh	3.215	¢	$2,567,362	3.532	¢	$2,820,504
Total	91,524,554				$4,401,097			$4,737,441
						Change		$336,344

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. 36 (Mirror Sch 23) - Industrial Partial Requirements Service - (Primary)								
Transmission & Ancillary Services Charge								
per kWh	2,279	kWh	0.472	¢	$11	0.464	¢	$11
Distribution Charge								
Basic Charge								
Single Phase, per month	0	bill	$9.90		$0	$16.55		$0
Three Phase, per month	12	bill	$14.80		$178	$24.75		$297
Load Size Charge								
≤ 15 kW	84	kW	No Charge			No Charge		
per kW for all kW in excess of 15 kW	71	kW	$0.70		$50	$1.15		$82
Demand Charge, the first 15 kW of demand	15	kW	No Charge			No Charge		
Demand Charge, per kW for all kW in excess of 15 kW	6	kW	$2.31		$14	$3.76		$23
Reactive Power Charge, per kvar	161	kvar	60.00	¢	$97	60.00	¢	$97
Distribution Energy Charge, per kWh	2,279	kWh	0.924	¢	$21	2.245	¢	$51
kvarh Charge, per kvarh	161	kvarh	0.080	¢	$0			
Standby Charge, per kW	0	kW	$1.16		$0			
Overrun Demand Charge, per kW	0	kW	$9.24		$0			
Energy Charge (Sch 200)								
1st 3,000 kWh, per kWh	2,279	kWh	4.325	¢	$99	4.013	¢	$91
All additional kWh, per kWh	0	kWh	3.121	¢	$0	2.895	¢	$0
Overrun kWh Charge, per kWh	0	kWh	6.242	¢	$0			
Total	2,279				$470			$652
						Change		$182
Schedule No. 36 (Mirror Sch 28) - Commercial Partial Requirements Service - (Primary)								
Transmission & Ancillary Services Charge per kW	3,565	kW	$2.00		$7,130	$1.28		$4,563
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, per month	0	bill	$17.00		$0	$19.00		$0
Load Size 51-100 kW, per month	23	bill	$30.00		$690	$33.00		$759
Load Size 101-300 kW, per month	32	bill	$70.00		$2,240	$76.00		$2,432
Load Size > 300 kW, per month	0	bill	$100.00		$0	$109.00		$0
Load Size Charge								
≤ 50 kW	0	kW	$0.95		$0	$1.05		$0
51-100 kW, per kW	819	kW	$0.78		$639	$0.85		$696
101-300 kW, per kW	4,093	kW	$0.41		$1,678	$0.45		$1,842
>300 kW, per kW	0	kW	$0.31		$0	$0.35		$0
Demand Charge, per kW	3,565	kW	$3.00		$10,695	$3.31		$11,800
Reactive Power Charge, per kvar	536	kvar	60.00	¢	$322	60.00	¢	$322
Distribution Energy Charge, per kWh	776,848	kWh	0.050	¢	$388	0.058	¢	$451
kvarh Charge, per kvarh	6,416,976	kvarh	0.080	¢	$5,134			
Standby Charge, per kW	1,644	kW	$2.50		$4,110			
Overrun Demand Charge, per kW	0	kW	$20.00		$0			
Energy Charge (Sch 200)								
1st 20,000 kWh, per kWh	540,448	kWh	3.292	¢	$17,792	3.638	¢	$19,661
All additional kWh, per kWh	236,400	kWh	3.196	¢	$7,555	3.532	¢	$8,350
Overrun kWh Charge, per kWh	0	kWh	6.392	¢	$0			
Total	776,848				$58,373			$50,876
						Change		($7,497)

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. 36 (Mirror Sch 30) - Composite Partial Requirements Service - (Primary)								
Transmission & Ancillary Services Charge per kW	12,181	kW	$1.60		$19,490	$1.42		$17,297
Distribution Charge								
Basic Charge								
Load Size ≤ 200 kW, per month	0	bill	$310.00		$0	$312.00		$0
Load Size 201-300 kW, per month	0	bill	$100.00		$0	$101.00		$0
Load Size > 300 kW, per month	51	bill	$260.00		$13,260	$262.00		$13,362
Load Size Charge								
≤ 200 kW	0	kW	$0.00		$0	$0.00		$0
201-300 kW, per kW	0	kW	$1.05		$0	$1.05		$0
>300 kW, per kW	15,800	kW	$0.55		$8,690	$0.55		$8,690
Demand Charge, per kW	12,181	kW	$2.46		$29,965	$2.48		$30,209
Reactive Power Charge, per kvar	100,881	kvar	60.00	¢	$60,528	60.00	¢	$60,528
kvarh Charge, per kvarh	13,435,756	kvarh	0.080	¢	$10,749			
Standby Charge, per kW	6,080	kW	$2.03		$12,342			
Overrun Demand Charge, per kW	1,617	kW	$16.24		$26,260			
Energy Charge (Sch 200)								
1st 20,000 kWh, per kWh	488,941	kWh	3.233	¢	$15,808	4.303	¢	$21,040
All additional kWh, per kWh	3,000,932	kWh	3.215	¢	$96,480	3.532	¢	$105,993
Overrun kWh Charge, per kWh	5,179	kWh	6.430	¢	$333			
Total	3,489,873				$293,572			$257,119
						Change		($36,453)

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

Schedule No. 41/741
Agricultural Pumping Service (Secondary)

Schedule	Forecast 1/06 - 12/06 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Transmission & Ancillary Services Charge								
per kWh	118,197,254	kWh	0.443	¢	$523,614	0.449	¢	$530,706
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, or Single Phase Any Size	5,772		No Charge			No Charge		
Three Phase Load Size 51 - 300 kW, per month	441	bill	$300.00		$132,300	$350.00		$154,350
Three Phase Load Size > 300 kW, per month	12	bill	$1,200.00		$14,400	$1,400.00		$16,800
Total Customers	6,225							
Total Bills	32,984							
Load Size Charge								
Single Phase Any Size, Three Phase ≤ 50 kW	67,373	kW	$15.00		$1,010,595	$18.00		$1,212,714
Three Phase 51-300 kW, per kW	35,525	kW	$9.00		$319,725	$11.00		$390,775
Three Phase > 300 kW, kW	5,174	kW	$6.00		$31,044	$7.00		$36,218
Single Phase, Minimum Charge	663	bill	$50.00		$33,150	$58.00		$38,454
Three Phase, Minimum Charge	1,287	bill	$90.00		$115,830	$105.00		$135,135
Distribution Energy Charge, per kWh	118,197,254	kWh	3.579	¢	$4,230,280	4.097	¢	$4,842,541
Reactive Power Charge, per kvar	21,581	kvar	65.00	¢	$14,028	65.00	¢	$14,028
Energy Charge (Sch 200)								
Winter, 1st 100 kWh/kW, per kWh	956,115	kWh	4.935	¢	$47,184	5.741	¢	$54,891
Winter, All additional kWh, per kWh	1,230,688	kWh	3.269	¢	$40,231	3.803	¢	$46,803
Summer, All kWh, per kWh	116,010,451	kWh	3.269	¢	$3,792,382	3.803	¢	$4,411,877
Total	118,197,254				$10,304,763			$11,885,292
						Change		$1,580,529

Schedule No. 41/741
Agricultural Pumping Service (Primary)

Schedule	Forecast 1/06 - 12/06 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Transmission & Ancillary Services Charge								
per kWh	1,006,562	kWh	0.424	¢	$4,268	0.437	¢	$4,399
Distribution Charge								
Basic Charge								
Load Size ≤ 50 kW, or Single Phase Any Size	3		No Charge			No Charge		
Three Phase Load Size 51 - 300 kW, per month	0	bill	$200.00		$0	$260.00		$0
Three Phase Load Size > 300 kW, per month	1	bill	$700.00		$700	$920.00		$920
Total Customers	4							
Total Bills	31							
Load Size Charge								
Single Phase Any Size, Three Phase ≤ 50 kW	15	kW	$10.00		$150	$13.00		$195
Three Phase 51-300 kW, per kW	0	kW	$5.00		$0	$7.00		$0
Three Phase > 300 kW, kW	453	kW	$4.00		$1,812	$5.00		$2,265
Single Phase, Minimum Charge	0	bill	$30.00		$0	$40.00		$0
Three Phase, Minimum Charge	1	bill	$50.00		$50	$65.00		$65
Distribution Energy Charge, per kWh	1,006,562	kWh	0.656	¢	$6,603	1.448	¢	$14,575
Reactive Power Charge, per kvar	1,587	kvar	60.00	¢	$952	60.00	¢	$952
Energy Charge (Sch 200)								
Winter, 1st 100 kWh/kW, per kWh	27,208	kWh	4.705	¢	$1,280	5.582	¢	$1,519
Winter, All additional kWh, per kWh	137,099	kWh	3.117	¢	$4,273	3.698	¢	$5,070
Summer, All kWh, per kWh	842,255	kWh	3.117	¢	$26,253	3.698	¢	$31,147
Total	1,006,562				$46,341			$61,107
						Change		$14,766

Schedule	Forecast 1/06 - 12/06 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Schedule 33 - USBR\UKRB	2,110							
Rate 35	44,445,269	kWh	0.750	¢	$333,340	0.750	¢	$333,340
Rate 40	43,433,762	kWh	0.600	¢	$260,603	0.600	¢	$260,603
Rate 33	2,730,398	kWh	0.371	¢	$10,130	0.371	¢	$10,130
Total	90,609,429	kWh			$604,073			$604,073
						Change		$0

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. 47/747 - Industrial								
Large General Service - Partial Requirement (Primary)								
Transmission & Ancillary Services Charge								
per kW of billing demand	812,180	kW	$1.64		$1,331,975			
per kW of on-peak demand	810,080	kW				$1.17		$947,794
Distribution Charge								
Basic Charge								
Load Size ≤ 4,000 kW, per month	0	bill	$220.00		$0	$250.00		$0
Load Size > 4,000 kW, per month	48	bill	$400.00		$19,200	$460.00		$22,080
Load Size/Facility Charge								
Load Size ≤ 4,000 kW, per kW	0	kW	$0.45		$0	$0.70		$0
Load Size > 4,000 kW, per kW	962,675	kW	$0.40		$385,070	$0.60		$577,605
Demand Charge, per kW of billing demand	812,180	kW	$1.42		$1,153,296			
Demand Charge, per kW of on-peak demand	810,080	kW				$1.48		$1,198,918
Reactive Power Charge, per kvar	119,909	kvar	60.00	¢	$71,945	60.00	¢	$71,945
kvarh, per kvarh	63,696,113	kvarh	0.080	¢	$50,957	0.080	¢	$50,957
Standby Charge, per kW	158,685	kW	$1.53		$242,788			
Overrun Demand Charge, per kW	4,773	kW	$12.24		$58,422			
Contingency Reserves Charges								
Spinning Reserves, per kW of Facility	962,675	kW				$0.27		$259,922
Supplemental Reserves, per kW of Facility	962,675	kW				$0.27		$259,922
Energy Charge (Sch 200)								
per kWh	136,771,435	kWh	2.869	¢	$3,923,972			
Overrun kWh	13,771	kWh	5.738	¢	$790			
per on-peak kWh	84,097,985	kWh				3.594	¢	$3,022,482
per off-peak kWh	52,673,450	kWh				3.294	¢	$1,735,063
Total	136,771,435				$7,238,415			$8,146,688
						Change		$908,273

Schedule	Forecast 1/06 - 12/06 Units		Present Price		Present Dollars	Proposed Price		Proposed Dollars
Schedule No. 47/747 - Composite								
Large General Service - Partial Requirement (Transmission)								
Transmission & Ancillary Services Charge								
per kW of billing demand	303,272	kW	$1.87		$567,119			
per kW of on-peak demand	302,488	kW				$1.52		$459,782
Distribution Charge								
Basic Charge								
Load Size ≤ 4,000 kW, per month	12	bill	$200.00		$2,400	$280.00		$3,360
Load Size > 4,000 kW, per month	24	bill	$370.00		$8,880	$530.00		$12,720
Load Size/Facility Charge								
Load Size ≤ 4,000 kW, per kW	30,307	kW	$0.40		$12,123	$0.40		$12,123
Load Size > 4,000 kW, per kW	401,587	kW	$0.40		$160,635	$0.40		$160,635
Demand Charge, per kW of billing demand	303,272	kW	$0.55		$166,800			
Demand Charge, per kW of on-peak demand	302,488	kW				$1.03		$311,563
Reactive Power Charge, per kvar	83,477	kvar	55.00	¢	$45,912	55.00	¢	$45,912
kvarh, per kvarh	21,947,445	kvarh	0.08	¢	$17,558	0.08	¢	$17,558
Standby Charge, per kW	130,210	kW	$1.21		$157,554			
Overrun Demand Charge, per kW	0	kW	$9.68		$0			
Contingency Reserves Charges								
Spinning Reserves, per kW of Facility	431,894	kW				$0.27		$116,611
Supplemental Reserves, per kW of Facility	431,894	kW				$0.27		$116,611
Energy Charge (Sch 200)								
per kWh	93,522,427	kWh	2.685	¢	$2,511,077			
Overrun kWh	0	kWh	5.370	¢	$0			
per on-peak kWh	57,505,046	kWh				3.420	¢	$1,966,673
per off-peak kWh	36,017,381	kWh				3.120	¢	$1,123,742
Total	93,522,427				$3,650,058			$4,347,290
						Change		$697,232

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				$1.59		$3,656,173
Distribution Charge								
Basic Charge								
Load Size ≤ 4,000 kW, per month	1,638	bill	$240.00		$393,120	$280.00		$458,640
Load Size > 4,000 kW, per month	43	bill	$440.00		$18,920	$520.00		$22,360
Load Size/Facility Charge								
Load Size ≤ 4,000 kW, per kW	2,444,513	kW	$0.50		$1,222,257	$1.45		$3,544,544
Load Size > 4,000 kW, per kW	302,852	kW	$0.45		$136,283	$1.30		$393,708
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				$1.34		$3,081,303
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				3.787	¢	$20,905,247
per off-peak kWh	349,367,402	kWh				3.487	¢	$12,182,441
Total	901,394,001				$38,668,066			$44,672,353
						Change		$6,004,287
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				$1.71		$6,775,642
Distribution Charge								
Basic Charge								
Load Size ≤ 4,000 kW, per month	679	bill	$220.00		$149,380	$250.00		$169,750
Load Size > 4,000 kW, per month	401	bill	$400.00		$160,400	$460.00		$184,460
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				$1.48		$5,864,299
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				3.594	¢	$41,221,255
per off-peak kWh	725,881,137	kWh				3.294	¢	$23,910,525
Total	1,872,827,573				$68,764,783			$81,697,930
						Change		$12,933,147

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 - 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			$2.06	$1,937,720
Distribution Charge						
Basic Charge						
Load Size ≤ 4,000 kW, per month	0	bill	$200.00	$0	$280.00	$0
Load Size > 4,000 kW, per month	12	bill	$370.00	$4,440	$530.00	$6,360
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
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			$1.03	$968,860
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			3.420 ¢	$11,766,866
per off-peak kWh	270,069,921	kWh			3.120 ¢	$8,426,182
Total	614,130,342			$19,308,825		$23,609,445
					Change	$4,300,620
Schedule No. 54/754						
Recreational Field Lighting						
Transmission & Ancillary Services Charge						
per kWh	760,384	kWh	0.011 ¢	$84	0.010 ¢	$76
Distribution Charge						
Basic Charge, Single Phase, per month	722	bill	$6.00	$4,332	$6.00	$4,332
Basic Charge, Three Phase, per month	374	bill	$9.00	$3,366	$9.00	$3,366
Distribution Energy Charge, per kWh	760,384	kWh	5.973 ¢	$45,418	5.614 ¢	$42,688
Energy Charge (Sch 200)						
per kWh	760,384	kWh	1.608 ¢	$12,227	1.525 ¢	$11,596
Total	760,384	kWh		$65,427		$62,058
					Change	($3,369)
Schedule No. 15 - Composite						
Outdoor Area Lighting Service						
No. of Customers	7,933					
Transmission & Ancillary Services Charge						
per kWh	12,626,392	kWh	0.015 ¢	$1,894	0.014 ¢	$1,768
Distribution Charge						
Distribution Charge, per kWh	12,626,392	kWh	10.356 ¢	$1,307,589	9.823 ¢	$1,240,291
Energy Charge (Sch 200)						
per kWh	12,626,392	kWh	2.174 ¢	$274,498	2.062 ¢	$260,356
Total	12,626,392	kWh	12.545 ¢	$1,583,981		$1,502,415
					Change	($81,566)
Schedule No. 50						
Mercury Vapor Street Lighting Service						
No. of Customers	316					
Transmission & Ancillary Services Charge						
per kWh	11,391,000	kWh	0.013 ¢	$1,481	0.012 ¢	$1,367
Distribution Charge						
Distribution Charge, per kWh	11,391,000	kWh	9.157 ¢	$1,043,074	8.686 ¢	$989,422
Energy Charge (Sch 200)						
per kWh	11,391,000	kWh	1.809 ¢	$206,063	1.716 ¢	$195,470
Total	11,391,000	kWh	10.979 ¢	$1,250,618		$1,186,259
					Change	($64,359)

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. 51/751								
High Pressure Sodium Vapor Street Lighting Service								
No. of Customers	667							
Transmission & Ancillary Services Charge								
per kWh	16,349,118	kWh	0.020	¢	$3,270	0.019	¢	$3,106
Distribution Charge								
Distribution Charge, per kWh	16,349,118	kWh	14.758	¢	$2,412,803	13.998	¢	$2,288,550
Energy Charge (Sch 200)								
per kWh	16,349,118	kWh	2.854	¢	$466,604	2.707	¢	$442,571
Total	16,349,118	kWh	17.632	¢	$2,882,677			$2,734,227
						Change		($148,450)
Schedule No. 52/752								
Company-Owned Street Lighting Service								
No. of Customers	111							
Transmission & Ancillary Services Charge								
per kWh	1,998,000	kWh	0.015	¢	$300	0.014	¢	$280
Distribution Charge								
Distribution Charge, per kWh	1,998,000	kWh	9.432	¢	$188,451	8.947	¢	$178,761
Energy Charge (Sch 200)								
per kWh	1,998,000	kWh	2.187	¢	$43,696	2.074	¢	$41,439
Total	1,998,000	kWh	11.634	¢	$232,447			$220,480
						Change		($11,967)
Schedule No. 53/753								
Customer-Owned Street Lighting Service								
No. of Customers	229							
Transmission & Ancillary Services Charge								
per kWh	8,399,592	kWh	0.006	¢	$504	0.006	¢	$504
Distribution Charge								
Distribution Charge, per kWh	8,399,592	kWh	5.470	¢	$459,458	5.188	¢	$435,771
Energy Charge (Sch 200)								
per kWh	8,399,592	kWh	0.935	¢	$78,536	0.887	¢	$74,504
Total	8,399,592	kWh	6.411	¢	$538,498			$510,779
						Change		($27,719)
TOTAL OREGON	13,617,170,666				$807,243,978			$883,197,393
Employee Discount					($396,923)			($425,879)
TOTAL OREGON (WITH EMPLOYEE DISCOUNT)					$806,847,055			$882,771,514

Case UE-170
PPL Exhibit 1213
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of William R. Griffith

Estimated Revenues of Adjustment Schedules

July 2005

Table 1213 - 1: ANALYSIS OF STAFF'S PROPOSAL
INCLUDING THE EFFECTS OF THE ELIMINATION OF SCHEDULE 94
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)	%	Line No.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) (6) + (7)	(9)	(10)	(11) (9) + (10)	(12) (9) - (6)	(13) (12)/(6)	(14) (11) - (8)	(15) (14)/(8)	
	Residential															
1	Residential	4	4	460,491	5,079,177	$389,311	($559)	$388,752	$417,336	($15,186)	$402,150	$28,025	7.2%	$13,398	3.5%	1
2	**Total Residential**			460,491	5,079,177	$389,311	($559)	$388,752	$417,336	($15,186)	$402,150	$28,025	7.2%	$13,398	3.5%	2
	Commercial & Industrial															
3	Gen. Svc. < 31 kW	23/36	23	68,716	1,111,483	$74,368	$3,935	$78,303	$90,891	($8,536)	$82,355	$16,523	22.2%	$4,052	5.2%	3
4	Gen. Svc. 31 - 200 kW	28/36	28	9,809	2,110,361	$117,664	$7,912	$125,576	$117,841	$8,296	$126,137	$177	0.2%	$561	0.5%	4
5	Gen. Svc. 201 - 999 kW	30/36	30	1,017	1,436,166	$70,762	$5,802	$76,564	$75,889	$3,317	$79,206	$5,127	7.3%	$2,642	3.5%	5
6	Large General Service >= 1,000 kW	48	48	231	3,388,352	$126,742	$11,873	$138,615	$149,980	($4,132)	$145,848	$23,238	18.3%	$7,233	5.2%	6
7	Partial Req. Svc. >= 1,000 kW	47	47	7	230,294	$10,889	$488	$11,377	$12,494	($299)	$12,195	$1,605	14.7%	$818	7.2%	7
8	Agricultural Pumping Service	41	41	6,229	119,204	$10,351	($2,029)	$8,322	$11,946	($3,192)	$8,754	$1,595	15.4%	$432	5.2%	8
9	Agricultural Pumping - Other	33	33	2,110	90,609	$604	$0	$604	$604	$0	$604	$0	0.0%	$0	0.0%	9
10	**Total Commercial & Industrial**			88,119	8,486,469	$411,380	$27,981	$439,361	$459,645	($4,546)	$455,099	$48,265	11.7%	$15,738	3.6%	10
	Lighting															
11	Outdoor Area Lighting Service	15	15	7,933	12,626	$1,584	$47	$1,631	$1,503	$128	$1,631	($81)	-5.1%	$0	0.0%	11
12	Street Lighting Service	50	50	316	11,391	$1,251	$41	$1,292	$1,186	$106	$1,292	($65)	-5.2%	$0	0.0%	12
13	Street Lighting Service HPS	51	51	667	16,349	$2,883	$70	$2,953	$2,734	$219	$2,953	($149)	-5.2%	$0	0.0%	13
14	Street Lighting Service	52	52	111	1,998	$232	$7	$239	$220	$19	$239	($12)	-5.2%	$0	0.0%	14
15	Street Lighting Service	53	53	229	8,400	$538	$29	$567	$511	$56	$567	($27)	-5.0%	$0	0.0%	15
16	Recreational Field Lighting	54	54	91	760	$65	$2	$67	$62	$5	$67	($3)	-4.6%	$0	0.0%	16
17	**Total Public Street Lighting**			9,347	51,524	$6,553	$196	$6,749	$6,216	$533	$6,749	($337)	-5.1%	$0	0.0%	17
18	**Total Sales to Ultimate Consumers**			557,957	13,617,170	$807,244	$27,618	$834,862	$883,197	($19,199)	$863,998	$75,953	9.4%	$29,136	3.5%	18
19	**Employee Discount**				20,911	($397)	$1	($396)	($426)	$16	($410)	($29)		($14)		19
20	**Total Sales with Employee Discount**			557,957	13,617,170	$806,847	$27,619	$834,466	$882,771	($19,183)	$863,588	$75,924	9.4%	$29,122	3.5%	20
21	AGA Revenue					$1,404		$1,404	$1,404		$1,404	$0		$0		21
22	**Total Sales with Employee Discount and AGA**			557,957	13,617,170	$808,251	$27,619	$835,870	$884,175	($19,183)	$864,992	$75,924	9.4%	$29,122	3.5%	22

[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] Excludes effects of Deferred Accounting Adjustment (Schedule 94) and includes new Sch 95 Miscellaneous Deferred Credit $1.8 million.

Table 1213 - 2: ANALYSIS OF STAFF'S PROPOSAL
PACIFIC POWER & LIGHT COMPANY
ESTIMATED REVENUES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2006

Line No.	Description	Pre Sch No.	Pro Sch No.	D ACNT 94 ($000)	Y2K 96 ($000)	CTL 97 ($000)	T MTN 198 ($000)	291 292 293 ($000)	RMA 299 ($000) PRE	RMA 299 ($000) PRO	Mis Credit 95 ($000)	Total ($000) PRE	Total ($000) PRO
	Residential												
1	Residential	4	4	$16,964	$102	($9,701)	$1,016	$914	($9,854)	($6,857)	($660)	($559)	($15,186)
2	**Total Residential**												
	Commercial & Industrial												
3	Gen. Svc. < 31 kW	23/36	23	$3,712	$23	($2,123)	$222	$667	$1,434	($7,180)	($145)	$3,935	($8,536)
4	Gen. Svc. 31 - 200 kW	28/36	28	$7,045	$43	($4,030)	$422	$1,140	$3,292	$10,995	($274)	$7,912	$8,296
5	Gen. Svc. 201 - 999 kW	30/36	30	$4,783	$29	($2,743)	$286	$776	$2,671	$5,156	($187)	$5,802	$3,317
6	Large General Service >= 1,000 kW	48	48	$10,889	$67	($6,472)	$579	$1,830	$4,980	$305	($441)	$11,873	($4,132)
7	Partial Req. Svc. >= 1,000 kW	47	47	$438	$5	($440)	$22	$124	$339	$20	($30)	$488	($299)
8	Agricultural Pumping Service	41	41	$398	$2	($228)	$23	$72	($2,296)	($3,046)	($15)	($2,029)	($3,192)
9	Agricultural Pumping - Other	33	33	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	**Total Commercial & Industrial**			$27,265	$169	($16,036)	$1,554	$4,609	$10,420	$6,250	($1,092)	$27,981	($4,546)
	Lighting												
11	Outdoor Area Lighting Service	15	15	$42	$0	($24)	$1	$7	$21	$145	($1)	$47	$128
12	Street Lighting Service	50	50	$38	$0	($22)	$1	$7	$17	$121	($1)	$41	$106
13	Street Lighting Service HPS	51	51	$55	$0	($31)	$3	$10	$33	$239	($2)	$70	$219
14	Street Lighting Service	52	52	$7	$0	($4)	$0	$1	$3	$22	$0	$7	$19
15	Street Lighting Service	53	53	$28	$0	($16)	$1	$5	$11	$67	($1)	$29	$56
16	Recreational Field Lighting	54	54	$3	$0	($1)	$0	$0	$0	$6	$0	$2	$5
17	**Total Public Street Lighting**			$173	$0	($98)	$6	$30	$85	$600	($5)	$196	$533
18	**Total**			$44,402	$271	($25,835)	$2,576	$5,553	$651	($7)	($1,757)	$27,618	($19,199)
19	**Employee Discount**			($17)	$0	$10	($1)	($1)	$10	$7	$1	$1	$16
20	**Total Sales with Employee Discount**			$44,385	$271	($25,825)	$2,575	$5,552	$661	$0	($1,756)	$27,619	($19,183)

Table 1213 - 3: ANALYSIS OF STAFF'S PROPOSAL
PACIFIC POWER & LIGHT COMPANY
PRESENT AND PROPOSED RATES OF ADJUSTMENT SCHEDULES
FORECAST 12 MONTHS ENDED DECEMBER 31, 2006

Line No.	Description	Pre Sch No.	Pro Sch No.	D ACNT 94S ¢/kWh	D ACNT 94P ¢/kWh	D ACNT 94T ¢/kWh	Y2K 96 ¢/kWh	CTL 97 ¢/kWh	T MTN 198S ¢/kWh	T MTN 198P ¢/kWh	T MTN 198T ¢/kWh	291 292 293 ¢/kWh	RMA 299 ¢/kWh PRE	RMA 299 ¢/kWh PRO	Mis Credit 95 ¢/kWh
	Residential														
1	Residential	4	4	0.334			0.002	(0.191)	0.020			0.018	(0.194)	(0.135)	(0.013)
	Commercial & Industrial														
2	Gen. Svc. < 31 kW	23	23	0.334	0.320		0.002	(0.191)	0.020	0.019		0.060	0.129	(0.646)	(0.013)
3	Gen. Svc. 31 - 200 kW	28	28	0.334	0.320		0.002	(0.191)	0.020	0.019		0.054	0.156	0.521	(0.013)
4	Gen. Svc. 201 - 999 kW	30	30	0.334	0.320		0.002	(0.191)	0.020	0.019		0.054	0.186	0.359	(0.013)
5	Large General Service >= 1,000 kW	48	48	0.334	0.320	0.307	0.002	(0.191)	0.018	0.017	0.016	0.054	0.147	0.009	(0.013)
6	Partial Req. Svc. >= 1,000 kW	47	47	0.334	0.320		0.002	(0.191)	0.017	0.016		0.054	0.147	0.009	(0.013)
7	Agricultural Pumping Service	41	41	0.334	0.320		0.002	(0.191)	0.019	0.018		0.060	(1.926)	(2.555)	(0.013)
8	Agricultural Pumping - Other	33	33	0.000	0.000		0.000	0.000	0.000	0.000		0.000	0.000	0.000	0.000
	Lighting														
9	Outdoor Area Lighting Service	15	15	0.334			0.002	(0.191)	0.012			0.060	0.160	1.145	(0.013)
10	Street Lighting Service	50	50	0.334			0.002	(0.191)	0.011			0.060	0.145	1.058	(0.013)
11	Street Lighting Service HPS	51	51	0.334			0.002	(0.191)	0.017			0.060	0.199	1.463	(0.013)
12	Street Lighting Service	52	52	0.334			0.002	(0.191)	0.013			0.060	0.150	1.100	(0.013)
13	Street Lighting Service	53	53	0.334			0.002	(0.191)	0.006			0.060	0.130	0.800	(0.013)
14	Recreational Field Lighting	54	54	0.334			0.002	(0.191)	0.010			0.060	0.060	0.800	(0.013)

1301 Martin Testimony

Case UE-170
PPL Exhibit 1301
Witness: Larry O. Martin

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-Surrebuttal Testimony of Larry O. Martin

Tax

July 2005

Q. Are you the same Larry O. Martin who previously filed rebuttal testimony in this proceeding?

A. Yes.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I provide testimony in response to the surrebuttal testimony of:

- Bryan Conway and Judy Johnson submitted on behalf of the Staff of the Oregon Public Utilities Commission (Staff);
- Bob Jenks submitted on behalf of Citizens' Utility Board of Oregon (CUB); and
- James T. Selecky submitted on behalf of Industrial Consumers of Northwest Utilities (ICNU).

Q. Please outline your testimony.

A. My sur-surrebuttal testimony responds to the newly proposed consolidated tax adjustment reflected in the joint rebuttal testimony of Staff witnesses Mr. Conway and Ms. Johnson. In particular, I address whether the Staff proposal is consistent with the "benefits and burdens" test, which the Department of Justice (DOJ) has advised is a prerequisite to any consolidated tax adjustment.

My sur-surrebuttal testimony also responds to new arguments in Messrs. Jenks' and Selecky's testimony. In particular, I address whether the proposals are methodologically sound, identify certain assertions in Messrs. Jenks' and Selecky's testimony that are inconsistent with accounting principles and tax law, and discuss some of the risks associated with the proposed consolidated tax adjustments.

The overall benefits of the ScottishPower capital structure on the Company's credit ratings is addressed in the direct and surrebuttal testimony of Bruce Williams. For the reasons described in detail in Mr. Williams' and my testimony, the proposed adjustments are flawed; inconsistent with Oregon Administrative Rules, past Commission treatment of the issue and sound regulatory principles; expose customers to volatile costs and risks; and, should be rejected.

Staff's Consolidated Tax Adjustment

Q. Please summarize the consolidated tax adjustment proposed by Staff in this proceeding.

A. Staff propose a consolidated tax adjustment to allocate the tax benefits of an affiliated entity's deductible expense to customers. Specifically, Staff propose to allocate a portion of the tax deduction created by PacifiCorp's parent company's, Pacificorp Holdings, Inc.'s (PHI), interest payments. Staff propose a $4.6 million adjustment to PacifiCorp's Oregon-allocated revenue requirement.

Q. Is Staff's adjustment consistent with the stand-alone method?

A. No. Staff's proposed adjustment—like CUB's, ICNU's and Utility Reform Project's proposed adjustments—would allocate to customers the tax benefits of an affiliated entity's expense. Despite this, Staff's testimony recognizes that the stand-alone method is superior to other methods and asserts that their adjustment is calculated on a stand-alone basis.

Q. How does Staff justify this inconsistency?

A. Staff, like CUB, rationalizes departure from the stand-alone method by asserting two things: (1) that the ring-fence between PacifiCorp's customers and PacifiCorp's affiliated entities has already been penetrated and (2) that customers are entitled to a share of an affiliated entity's tax benefits if customers bore the burden of creating that tax benefit. With respect to the first assertion, Staff and CUB argue that the ring-fence is penetrable because the financial strength of PacifiCorp's corporate family impacts PacifiCorp's credit rating. They argue that, regardless of whether the net impact on PacifiCorp is positive or negative, the fact that there is any impact supports an allocation of the tax effects of the parent's interest payments to customers. With respect to the second assertion, Staff and CUB argue that customers bear the burden of PHI's debt and are therefore entitled to the benefit of the interest deduction.

Q. Do Staff apply the "benefits and burdens" test correctly?

A. No. Staff's misapply the "benefits and burdens" test by focusing not on the deductible expense, which is PHI's obligation to make payments on the debt, but rather on the debt itself absent the obligation to make payments. Indeed, Staff acknowledges that "customers have no obligation to pay the debt." (Staff/1000/Conway-Johnson/4.)

Q. Why do you say that the "benefits and burdens" test focuses on the deductible expense?

A. My explanation of the "benefits and burdens" test mirrors the description of the test in the DOJ's March 22, 2005, memorandum to the Commission, which advised that:

> Taking into account the "benefits and burdens" . . . means that the benefits of consolidated tax savings are given to ratepayers (by reducing the utility's tax allowance) if the customers bore the burden of *paying the deductible expenses that generated the savings.*

This principle was also reflected in the White Paper on Treatment of Income Taxes in Utility Ratemaking, which stated:

> Unless the underlying revenues and costs of the parent and subsidiaries were also reflected in rates, setting rates based on consolidated tax payments would be considered poor regulatory policy . . . Regulators should reflect tax benefits in rates to the same extent that customers bear the expenses creating those benefits.

In other words, the test asks whether the expenses or losses that created the tax credits or deductions are included in the cost of service? Here, the tax "savings" arise from the interest payments on the debt, so the "deductible expense" is the interest payment—*i.e.,* the burden of the debt is the interest payment. Thus, the question is whether the customers bear the burden of the debt by paying the interest payment that generated the interest deduction.

Q. Is the deductible expense that generated the tax savings included in the cost of service?

A. No. Neither Staff nor CUB assert that the deductible expense is included in the cost of service. As I explained in my rebuttal testimony, PacifiCorp's shareholder, not the customers, pay the expense (the interest payment) that created the tax deduction.

Q. Does Staff demonstrate that customers bear the burden of PHI's obligation in some other way?

A. No. Mr. Conway and Ms. Johnson do not demonstrate that customers bear the burden of PHI's obligation. Rather, they speculate that customers "*could* bear some burden associated with PHI['s] debt." (Staff/1000/Conway-Johnson/4.)

Q. Does Staff demonstrate that customers are negatively impacted by PHI's debt?

A. No. Mr. Conway and Ms. Johnson do not demonstrate that customers are negatively impacted by PHI's debt. Rather, they speculate that "[c]ustomers *could be* negatively impacted by PHI debt even though customers have no obligation to pay the debt." When asked the basis for this statement, Staff provided no workpapers or explanation beyond their testimony. (PPL Exhibit 1302 (Staff Response to OPUC Data Request 5.11).)

This is particularly troubling in light of Mr. Conway's and Ms. Johnson's equivocation on whether a burden even exists. For example, when asked whether ring-fencing has insulated customers from burdens related to PHI, they respond "Perhaps." (Staff/1000/Conway-Johnson/6.) Likewise, when asked whether customers bear the burden of PHI debt as a result of the debt's impact on bond ratings, they again respond "Perhaps." (Staff/1000/Conway-Johnson/9.)

Q. Please address Staff's argument that the impact of the common parent's financial strength on PacifiCorp's credit rating could constitute a burden on customers.

A. Staff argues that the financial strength of PHI, ScottishPower and the entire affiliated group impacts PacifiCorp's credit rating, and that this impact may constitute a burden on customers with respect to PHI's debt. However, Staff equivocates on this point as well, concluding that:

> . . . PacifiCorp's ratings suffer due to debt at PHI but, PacifiCorp's ratings are currently benefited by PacifiCorp's relation to ScottishPower. *The net result of these two effects is unknown.* (Staff/1000/Conway-Johnson/7 (emphasis added).)

> [S]ome customer harm *may have* occurred. Based on existing information, it is difficult to be precise in determining what PacifiCorp's rating would be absent the debt at PHI. (Staff/1000/Conway-Johnson/10 (emphasis added).)

In contrast, Mr. Williams' rebuttal and sur-surrebuttal testimony demonstrates unequivocally that the financial strength of PacifiCorp's parents has benefited, not burdened, customers.

Q. Does Staff's argument that PHI debt may negatively impact PacifiCorp's credit rating provide a basis for Staff's proposed adjustment?

A. No. Staff, like CUB and ICNU, focus their tax adjustment on a single expense item—the interest payments on the loan that PHI used to acquire PacifiCorp. Even if Staff, CUB or ICNU demonstrated a burden on customers caused by the PHI debt, an adjustment based on this single expense item would create a windfall for customers. Insofar as intervenors argue that this expense item harms customers, they are seeking to relitigate UM 918. Recognizing this point, Mr. Conway and Ms. Johnson acknowledge that "some consideration should be given to the tax treatment in a general rate case to reflect the agreements adopted by the Commission, if any, when the holding company was formed." (Staff/1000/Conway-Johnson/5.) In UM 918, the Commission considered potential burdens on customers of the acquisition and ordered compensation in the form of merger credits and merger conditions. (*See* UM 918, Order No. 99-616 (Ore. P.U.C. Oct. 6, 1999).) Recognizing this, Staff acknowledge that "conditions of the merger [such as the merger credits] could be sufficient to ensure that customers are held harmless." (Staff/1000/Conway-Johnson/7.)

Q. Have Staff or CUB provided any basis for determining what portion, if any, of the alleged burden on customers is in addition to the burden that has already been compensated for by the merger credits and conditions?

A. No. Neither Staff nor CUB provide any basis for determining what portion, if any, of the alleged burden on customers remains uncompensated after taking into account the merger credits and conditions. In fact, Staff and CUB fail to address the fact that the debt is now less than half the amount that the Commission contemplated when it issued Order No. 99-616, in which the Commission determined that the acquisition would create a net benefit for customers.

Flaws in CUB's and ICNU's Proposed Consolidated Tax Adjustments

Q. Please describe the allocation methodology proposed by Mr. Jenks.

A. Mr. Jenks proposes allocating the tax deduction from PHI's interest payments to PacifiCorp on a system net-plant basis.

Q. Is CUB's methodology sound?

A. No. CUB's methodology is flawed in three key respects. First, Mr. Jenks fails to adequately demonstrate that PHI's interest payment burdens customers. Second, he fails to account for the off-setting effect of the merger credits and conditions on any burden related to the acquisition. And, third, net plant does not have any relation to the interest deduction. Normally, inter-company allocations are based on relative taxable incomes. A more appropriate allocation basis would therefore be the relative taxable income of the members of the consolidated group.

Q. Mr. Jenks compares his proposed adjustment to shared corporate costs. Is this an appropriate comparison?

A. No. PacifiCorp would have costs for tax filing, shareholder services, and finance and corporate strategy whether or not it was held by a parent company. In contrast, the interest payment on PHI's debt is specific to PHI. Unless it is established that customers, and not investors, bear the burden of these payments, it is not appropriate or consistent with Commission policy to allocate the tax effects of these payments to customers.

Q. Are shared corporate costs an example of failed ring-fencing, as Mr. Jenks argues?

A. Absolutely not. Recognizing that PacifiCorp would incur these costs regardless of whether it is a member of an affiliated group or a standalone company, the Commission allocates to customers only that portion of the shared corporate costs that benefit customers. In this way, the Commission's approach to shared corporate costs is consistent with its ring-fencing policies.

Q. Please describe the allocation methodology proposed by Mr. Selecky.

A. Mr. Selecky proposes allocating the tax deduction from PHI's interest payments to PacifiCorp. He appears to base his allocation on the relative net book value of assets.

Q. Is ICNU's methodology sound?

A. No. ICNU's methodology is flawed in two key respects. First, ICNU fails to adequately demonstrate that PHI's interest payment burdens customers. Indeed, Mr. Selecky does not even argue that his proposed adjustment is based on the "benefits and burdens" test, but rather argues as a matter of policy that a consolidated tax adjustment is appropriate. (ICNU/211/Selecky/2.) This is despite the fact that Commission precedent and Oregon Administrative Rules require the Commission to base the tax expense in rates on the utility's regulated operations only (*i.e.,* on a stand-alone basis). Second, Mr. Selecky, like Mr. Jenks, does not base his allocation on the relative taxable income of the members of the consolidated group. Rather, Mr. Selecky appears to base his proposed adjustment on the relative net book value of assets. Like net plant, the net book value of assets has no relation to the interest deduction.

Q. Messrs. Jenks and Selecky assert that an adjustment based on PHI's interest deduction does not entail risks of future claims based on reversals of the tax savings in subsequent years. Do you agree?

A. No. Messrs. Jenks' and Selecky's discussion of the timing issue misconstrues the nature of the benefits associated with filing a return on a consolidated basis.

Q. Please summarize Messrs. Jenks' and Selecky's argument that the consolidated tax savings from PHI's interest deduction is a permanent benefit.

A. Messrs. Jenks and Selecky argue that, because the tax effect of PHI's interest expense is a deduction and not a deferral, the consolidated tax savings from PHI's interest deduction is a permanent benefit. (CUB/200/Jenks/9-12; ICNU/211/Selecky/3-5.)

Q. Is the consolidated tax savings from the interest deduction a permanent benefit?

A. No. Messrs. Jenks' and Selecky's arguments fail to recognize that the proposed tax adjustment is a consolidated tax adjustment. Any consolidated tax adjustment implicates timing differences by allocating to one entity the tax effect of filing on a consolidated basis, which effect will eventually reverse in the normal course of business. As I explained in my rebuttal testimony, one of the key reasons entities choose to participate in the filing of consolidated tax returns is because of timing differences. Filing a consolidated tax return effects the current taxes payable rather than the total income tax expense. In other words, the benefit, if any, of filing consolidated returns is the effect upon the timing of the income tax payment, not the total tax liability. The consolidated return may reduce current taxes owed (if there are losses to offset gains), but the result is that taxes in future years are increased and will ultimately become due. This is because, absent the consolidated return, the losses, including the interest deduction, would have carried forward to reduce taxes payable in a subsequent year.

Q. Is the federal income tax paid by PHI permanently reduced by its participation in the consolidated return?

A. No. As I explained in my rebuttal testimony, even when a consolidated income tax return is used, each affiliated entity's taxable income is separately reported to the IRS. Accordingly, the Company contributes to the consolidated group its separately calculated share of current income tax.

As explained above, consolidated tax adjustments made in the PHI consolidated return do not permanently minimize tax expense. Because taxes owed in subsequent years will be higher by an amount equal to the consolidated "savings," the only benefit to the company is the time value of money of the subsequent tax payment. Thus, the consolidated "savings" are a timing benefit only. This timing benefit is already allocated to customers through an adjustment to rate base.

Q. Messrs. Jenks and Selecky both argue that the adjustment does not implicate timing differences because the interest deductions are neither deferred taxes resulting from accelerated depreciation nor net operating losses. Are they correct?

A. No. While it is true that the interest deductions have nothing to do with accelerated depreciation, the interest expense, like other expenses, make up net operating losses. Because net operating losses can be carried forward into future periods, allocation of the consolidated benefits of net operating losses entail timing issues.

Q. Do these timing differences create rate volatility risks for customers?

A. Yes. As I explained in my rebuttal testimony, net operating losses are deferred tax items. Because deferrals eventually reverse, a consolidated tax adjustment based on PHI's net operating losses, assuming one were appropriate, would eventually result in a rate increase to compensate PHI for the loss of the future benefit.

Q. Is it true, as Mr. Jenks suggests, that PacifiCorp can easily elect to file taxes on a standalone basis?

A. No. While the decision to elect to deconsolidate is voluntary, the decision to make such an election is constrained by the Internal Revenue Code (IRC), which imposes onerous and potentially costly conditions on deconsolidating entities.

Q. What issues factor into a decision to deconsolidate?

A. As I explained in my rebuttal testimony, if corporations meet certain ownership thresholds the IRS will impose certain limitations on the group irrespective of whether the corporation elects to join in a consolidated tax return. For example, after an election to file a consolidated return has been made, the election is binding on all members of the group with 80% or greater common ownership. Notwithstanding this limitation, the IRS may approve of an election to file on a standalone basis if the group persuades the IRS that it has "good cause" to discontinue filing on a consolidated basis. "Good cause" ordinarily means a change in federal tax law that has a "substantial adverse effect" on the group's consolidated federal tax liability. If the group succeeds in making the election to discontinue filing on a consolidated basis, there is an issue as to whether there is an immediate tax cost. This is, in part, because tax generally is not collected on transactions among members of the group. That tax is deferred as long as all the affiliates remain in the group. When a group elects to discontinue filing on a consolidated basis, that event triggers tax on all past transactions between members of the affiliated group. If the group has filed on a consolidated basis for a long time, the built-up deferred tax amount can be substantial and may be a significant practical deterrent to an election to discontinue filing on a consolidated basis. Oregon law mirrors federal law in that it requires any group that files federal returns on a consolidated basis to file Oregon returns on a consolidated basis. ORS 317.710(2). Likewise, Oregon requires "unitary" entities such as PHI to file a consolidated return.

Q. Please respond to Mr. Jenks' argument that your use of the term "affiliated entity" to describe PHI "misrepresents CUB's testimony by failing to distinguish between affiliates and parent companies."

A. Mr. Jenks attempts to create a distinction between members of a consolidated group that does not exist. His argument apparently relies on a more general usage of the term affiliate. In the context of taxes, however, the ordinary usage is superseded by the specific statutory definition of the term, which includes the common parent.

Q. Is your usage of the term consistent with its specific tax meaning?

A. Yes. My use of the term "affiliated entity" is consistent with the IRC and Oregon tax law. The term used in the tax law is "affiliated group." The members of the affiliated group are called "includible corporations." The includible corporations are (i) a "common parent" and (ii) subsidiaries in the chain of ownership proceeding from the common parent. *See* IRC §1504(a)(1); ORS 317.705(1). Consistent with the IRC and Oregon tax law, "affiliated entity" and "affiliate" are shorthand for "member of the affiliated group" and "includible corporation."

Q. Are the risks of a consolidated tax adjustment lessened because the adjustment is based on the tax effects of an expense of the common parent as opposed to another member of the affiliated group?

A. No. The risks discussed in my rebuttal testimony are equally implicated whether the consolidated tax adjustment is based on a deductible expense borne by a parent, brother-sister affiliate or subsidiary. The federal consolidated return rules treat transactions among members of an affiliated group the same, regardless of whether the particular members involved in the transaction are the common parent or a subsidiary, or some other combination of includible corporations. Oregon similarly does not distinguish in any significant way between the parent and other members of the affiliated group.

Q. Would any of the proposed consolidated tax adjustments, if accepted, impact the Production Activity Deduction?

A. Yes. Any and all adjustments to the Company's revenue requirement in this case will affect the computation of the Production Activity Deduction.

Q. Please summarize your sur-surrebuttal testimony.

A. The Commission has historically taken great care to carefully separate PacifiCorp from its non-regulated affiliates in order to protect customers from potentially significant subsequent liabilities, from risk of non-regulated operations' losses, and from risk of rate volatility. The "benefits and burdens" test allows the Commission to look beyond the stand-alone tax expense to tax effects of non-regulated affiliates without jeopardizing the careful separation between regulated and non-regulated operations and imposing great risks on customers. The proposed consolidated tax adjustments fail to satisfy this test, because they fail to adequately demonstrate that customers bear the burden of the deductible expense that creates the consolidated tax savings. Consequently, the proposals inequitably allocate the tax benefits of PHI's losses to customers, are inconsistent with long-standing regulatory ratemaking principles and practice, and should be rejected.

Q. Does this conclude your sur-surrebuttal testimony?

A. Yes.

1302 Martin Exhibit

Case UE-170
PPL Exhibit 1302
Witness: Larry O. Martin

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of Larry O. Martin

Staff Response to OPUC Data Request 5.11

July 2005

5.11 Please provide a copy of all analyses (or if any such analysis is not in written form, a written description of such analysis) that Mr. Conway and Ms. Johnson rely on to support the assertions in their testimony at page 4, lines 18-19.

See Staff/1000, Conway-Johnson page 10 line 18 through page 16 line 11 and Staff/1002.

1601 Wrigley Testimony

Case UE-170
PPL Exhibit 1601
Witness: Paul M. Wrigley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Sur-Surrebuttal Testimony of Paul M. Wrigley

Revenue Requirement

July 2005

Q. Are you the same Paul M. Wrigley who previously filed rebuttal testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my sur-surrebuttal testimony is to update the Company's revenue requirement PPL Exhibit 801 to reflect the three Partial Stipulations already filed in this proceeding and additional updates proposed by the Company in its rebuttal and sur-surrebuttal testimony. In addition, I respond to ICNU witness Mr. Falkenberg's surrebuttal testimony and Staff witness Mr. Wordley's surrebuttal testimony addressing the issue of whether the level of the Company's investment in the Gadsby CT should be reduced by $7.5 million.

Updated Revenue Requirement

Q. Please describe PPL Exhibit 1602.

A. PPL Exhibit 1602 updates page 1.1 of PPL Exhibit 801, the Company's Results of Operations for the twelve month future period ended December 31, 2006. It shows that an overall price increase of $75.9 million is required to produce the 11.125% ROE supported by Dr. Hadaway's testimony.

Q. Please describe the revisions from the original revenue increase of $102 million shown in PPL Exhibit 801.

A. PPL Exhibit 1602 incorporates the following changes;

1. It includes the updates to revenue requirement described in the Partial Settlement filed with Commission on May 4th 2005. Two of the adjustments described in the Partial Settlement will be further updated

based upon the Commission's final action in this proceeding. As described in the Partial Settlement, the Company's income tax expense will be adjusted based upon the final weighted cost of debt and the Production Activity Deduction will be determined based upon the final revenue requirement authorized in this docket.

2. It includes the $2.41 million reduction in revenue requirement for full-time employee benefits described in the Second Partial Stipulation filed with the Commission on June 29th 2005.
3. It includes the Fuel Handling Change described in the Third Partial Stipulation filed with the Commission on June 29th 2005 which increases the Company's revenue requirement by $2.49 million. Concurrent with this change, I also include the correction for the James River royalty offset (Georgia Pacific), proposed in Staff witness Mr. Breen's direct testimony, my rebuttal testimony and Mr. Falkenberg's surrebuttal testimony, which reduces Oregon's purchased power expense by $2.05 million.
4. As described in Mr. Rosborough's sur-surrebuttal testimony, the Company is updating the pension expense included in the filing to reflect the actual known and measurable pension expense for Fiscal Year 2006 of $49.855 million as compared to the $42.2 million included in the Company's original filing. The Company has also updated its FAS 106 expense to reflect actual 2005 expense which reflects savings associated with recent Medicare legislation. This results in a decrease of FAS 106 expense from

$26.8 million to $24 million. The Company has also conceded Staff witness Mr. Dougherty's pension administration adjustment and lowered the total pension administration amount included in the filing to $1.02 million.

5. Mr. Williams' sur-surrebuttal testimony reduces the embedded cost of debt from 6.35 percent to 6.288 percent and the cost of preferred stock from 6.63 percent to 6.59 percent and I have included that change in my calculation of revenue requirement.
6. As described in the Prehearing Conference Memorandum of June 30th, 2005 the current contact rates (Schedule 33) for the Klamath River Basin irrigators have been used in calculating this revenue requirement. Following previous practice, the discount is treated as a cost to PacifiCorp's entire hydro system rather than a state specific cost to ensure the costs and benefits associated with the discount are appropriately matched.

Gadsby Turbine

Q. Please respond to ICNU witness Mr. Falkenberg's surrebuttal testimony and Staff witness Mr. Wordley's surrebuttal testimony addressing whether the level of the Company's investment in the Gadsby CT should be reduced by $7.5 million.

A. Mr. Wordley and I are in agreement that the Commission should reject ICNU's proposed adjustment to decrease the level of the Gadsby CT plant in rate base by $7.5 million.

Mr. Falkenberg's argument that the Company might have been able to recover the peaker rental fee by choosing a different choice of test year is illogical – the Company didn't make the $7.5 million payment, so it never could have recovered the amount. Furthermore, the amount could not have been recovered through the UM 995 power cost deferral for three reasons:

1. The payment wasn't made;
2. Lease payments are not included in net power costs; and
3. Even if it had been made, the payment would have been after the end of the UM 995 deferral period.

Q. Were customers harmed by the Company's non-payment of the $7.5 million peaker rental fee?

A. No. As Mr. Falkenberg asserts, the Company retained the amount – only in the sense that the amount was never spent. This amount was never in rates so it is difficult to see how customers were harmed. Because the non-payment is reflected in lower Fiscal Year 2002 expense, the base year for determining the revenue requirement in UE 147. Oregon rate payers have benefited from this non-payment.

Q. Please respond to the contention that the Company wasn't interested in getting "the best deal for customers".

A. As Mr. Wordley says: "GE's offer, even excluding the waiver of the remaining lease obligation which was included in the order, was better than the Pratt & Whitney CT purchase…" Staff/800/Wordley/8. The deal was prudent, and therefore GE's negotiating stance is irrelevant.

Q. Please respond to the testimony of Mr. Moio, cited by Mr. Falkenberg.

A. As Mr. Falkenberg reports, the case in which this testimony was presented was settled so this testimony should carry no weight. In addition, it should carry no weight as Mr. Moio is not a witness in this proceeding and not available to be cross examined.

Q. Does this conclude your sur-surrebuttal testimony?

A. Yes.

1602 Wrigley Exhibit

Case UE-170
PPL Exhibit 1602
Witness: Paul M. Wrigley

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Sur-Surrebuttal Testimony of Paul M. Wrigley

Normalized Results of Operations – MSP Protocol

12 Months Ended December 2006

July 2005

PACIFICORP
OREGON
Normalized Results of Operations - MSP Protocol
12 Months Ended December 2006

		(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1	Operating Revenues:			
2	General Business Revenues	815,355,929	75,935,304	891,291,233
3	Interdepartmental	-		
4	Special Sales	190,420,306		
5	Other Operating Revenues	41,993,953		
6	Total Operating Revenues	1,047,770,188		
7				
8	Operating Expenses:			
9	Steam Production	198,260,694		
10	Nuclear Production	-		
11	Hydro Production	12,671,344		
12	Other Power Supply	254,297,732		
13	Transmission	31,649,943		
14	Distribution	67,294,763		
15	Customer Accounting	30,723,856	210,827	30,934,682
16	Customer Service & Info	3,550,131		
17	Sales	1,286		
18	Administrative & General	71,226,189		
19	Total O&M Expenses	669,675,938		
20	Depreciation	116,549,193		
21	Amortization	17,681,472		
22	Taxes Other Than Income	44,649,679	1,720,694	46,370,373
23	Income Taxes - Federal	44,555,345	24,725,404	69,280,749
24	Income Taxes - State	7,275,691	3,359,772	10,635,463
25	Income Taxes - Def Net	5,082,905		
26	Investment Tax Credit Adj.	-		
27	Misc Revenue & Expense	(157,967)		
28	Total Operating Expenses:	905,312,256	30,016,696	935,328,953
29				
30	Operating Rev For Return:	142,457,932	45,918,608	188,376,540
31				
32	Rate Base:			
33	Electric Plant In Service	4,295,806,268		
34	Plant Held for Future Use	0		
35	Misc Deferred Debits	37,112,878		
36	Elec Plant Acq Adj	22,088,848		
37	Nuclear Fuel	-		
38	Prepayments	7,434,535		
39	Fuel Stock	14,580,689		
40	Material & Supplies	27,114,872		
41	Working Capital	22,512,519		
42	Weatherization Loans	141,486		
43	Misc Rate Base	2,476,034		
44	Total Electric Plant:	4,429,268,130	-	4,429,268,130
45				
46	Rate Base Deductions:			
47	Accum Prov For Deprec	(1,750,770,829)		
48	Accum Prov For Amort	(134,809,077)		
49	Accum Def Income Tax	(326,838,164)		
50	Unamortized ITC	(8,522,767)		
51	Customer Adv For Const	5,611		
52	Customer Service Deposits	-		
53	Misc Rate Base Deductions	(39,504,761)		
54				
55	Total Rate Base Deductions	(2,260,439,987)	-	(2,260,439,987)
56				
57	Total Rate Base:	2,168,828,143	-	2,168,828,143
58				
59	Return on Rate Base	6.5684%		8.686%
60	Return on Equity	6.8478%		11.125%
61				
62	TAX CALCULATION:			
63	Operating Revenue	199,371,873	74,003,784	273,375,657
64	Other Deductions			
65	Interest (AFUDC)			
66	Interest	67,369,701	-	67,369,701
67	Schedule "M" Additions	147,834,546	-	147,834,546
68	Schedule "M" Deductions	142,035,277	-	142,035,277
69	Income Before Tax	137,801,441	74,003,784	211,805,224
70				
71	State Income Taxes	7,275,691	3,359,772	10,635,463
72	Taxable Income	130,525,750	70,644,012	201,169,762
73				
74	Federal Income Taxes + Other	44,555,345	24,725,404	69,280,749