BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

DIRECT TESTIMONY ON NON-POWER COST ISSUES OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

July 12, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am a utility regulatory consultant, and President of RFI Consulting, Inc. ("RFI"). I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY RFI?

A. RFI provides consulting services related to electric utility system planning, energy cost recovery issues, revenue requirement, cost of service, and rate design.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in Exhibit ICNU/101 attached to my testimony that was filed on June 30, 2006, in this proceeding.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. My testimony addresses a limited set of issues related to PacifiCorp's revenue requirements and the Hybrid comparator analysis presented by the Company in Exhibit PPL/901, tab 9b. I previously submitted testimony in this proceeding on net power cost issues.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

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

1. **PacifiCorp's normalized generation overhaul costs appear substantially overstated. The projected levels for the test year exceed actual and forecast expenditures every year for the period 2002-2006. To provide more realistic overhaul costs, I recommend a disallowance in the amount shown on Table 1.**

2. **PacifiCorp has an eighty-year contract to provide the Western Area Power Administration ("WAPA") transmission service. The Commission made an imprudence disallowance related to this contract in UE 116 because the contract lacks any price escalation provisions. The Utah Commission has also made disallowances related to this contract. I recommend a disallowance in the amount shown on Table 1 to address this problem.**

3. **PacifiCorp requests recovery of Senate Bill ("SB") 1149 implementation costs that appear to be excessive in relation to the limited direct access participation that has occurred in PacifiCorp's service territory. I recommend that the Commission remove these costs from rates. This disallowance is shown on Table 1.**

4. **The Company contends that its new "Hybrid Method" would produce an increase in Oregon revenue requirements of $46 million compared to the Revised Protocol allocation methodology. However, this result fails to provide a reasonable basis for comparison because of ad-hoc adjustments made to the model in the UM 1050 workshop process. I recommend the Commission reject this analysis.**

Table 1
Summary of Recommended Adjustments

	Total Company	Oregon Jurisdiction
1 Thermal Overhaul	$11,170,362	$2,958,659
2 WAPA Revenue	$3,153,903	$835,028
3 SB 1149 Cost	$1,406,094	$1,406,094
Total	$15,730,359	$5,199,781

Generation Overhaul Costs

Q. HAVE YOU REVIEWED PROFORMA ADJUSTMENT 4.8, GENERATION OVERHAUL NORMALIZATION?

A. Yes. In this adjustment, the Company "normalizes" actual generation overhaul expenses in fiscal year ("FY") 2005 to the level forecasted in calendar year ("CY") 2007. In making this adjustment, the Company notes that overhaul expenses in FY 2005 were low.

Q. DOES THIS ADJUSTMENT APPEAR TO BE REASONABLE?

A. No, there is ample room to question this adjustment. Certainly, there are reasons why 2005 expense levels may be lower than would occur under normal conditions. However, the level of the proposed adjustment appears excessive, particularly given the minimal support provided.

For FY 2002 to 2005 actual generation overhaul expense averaged $24.7 million. For the FY 2006 Budget, overhaul expenses were projected to be $27.1 million. In contrast, the Company assumes expenditures of $38.6 million for FY 2007 and $39.6 million for FY 2008.

One reason for this increase is that in FY 2007 Currant Creek is included for the first time at $523,000, and again in FY 2008, it is included at $4.5 million. Removing Currant Creek from the test year figures produces a result of $38.1 million for 2007 and $35.1 for 2008, for all of the plants other than Currant Creek. In the Company's methodology, normalized CY 2007 figures are estimated by taking 25% of FY 2007 figures and 75% of FY 2008. This results in a composite cost included in the test year of $35.9 million. This represents an increase of 45%

for generation overhaul costs over the actual figures from 2002 to 2005 ($24.7 million).

Q. DOES THE COMPANY EXPLAIN THIS INCREASE IN ITS TESTIMONY?

A. PP&L witness Barry Cunningham discusses this issue briefly on pages 4-7 of his testimony. PPL/700, Cunningham/4-7. His discussion is quite general in nature and provides few specifics as to the reasons for this substantial increase.

Q. DOES MR. CUNNINGHAM INDICATE THAT A POSSIBLE REASON FOR THIS INCREASE IS BECAUSE OVERHAUL WORK WAS DEFERRED IN 2005?

A. Mr. Cunningham addresses this question on page 6 of his testimony. PPL/700, Cunningham/6. He testifies the increase is not because work has not been deferred in the past. Instead, he contends such work cannot be deferred for more than a few months to a year.

Q. WHAT IS THE IMPLICATION OF THIS STATEMENT?

A. Mr. Cunningham indicates work cannot be deferred for any extended period of time. As a result, the figures for the period 2002 to 2005 should not have been reduced by a program of deferring overhauls. That being the case, there is no reason to expect that costs in those years are unrepresentative. For this reason, I believe that they provide a reasonable basis for comparison to the projected test year level.

Q. DO YOU HAVE ANY CONCERNS REGARDING THE PROPOSED TEST YEAR FIGURES?

A. Yes. I am concerned that the test year figures may represent a "wish list" of expenditures for various plants. It is not uncommon for plant personnel to identify a large number of projects and costs that they might desire to implement in order to improve plant performance. However, it frequently is the case that, when actual budget decisions are made, such requests are denied or substantially pared down. There is certainly a danger that these costs will be built into rate levels, but not actually spent to improve plant performance. As I showed in my net power cost testimony, PacifiCorp's generator fleet has shown a marked decline in reliability in recent years. Certainly, if additional spending is needed to reverse the decline, it would be money well spent. However, based on past expenditure levels, I see no basis for assuming the money will actually be spent in the test year.

Further, the decline in reliability by PacifiCorp's plants has been very costly. Unless the Commission makes an adjustment to reverse that decline in the power cost study, it would be inequitable to charge customers for the costs of improving reliability, but not providing any of the benefits. This would be the "worst of all possible worlds" from an equity standpoint.

Q. WHAT IS YOUR RECOMMENDATION?

A. In Exhibit ICNU/117, I present a calculation of overhaul costs based on a four-year average from 2002 to 2005. These figures would provide representative levels for the test year. I have computed an adjustment to replace Pro-Forma 4.8 based on the 2002 to 2005 average. I recommend the Commission reverse the Company adjustment and implement my proposed adjustment in its place. This reduces revenue requirements by $2.96 million on an Oregon basis.

WAPA Contract

Q. PLEASE EXPLAIN THE WAPA WHEELING RATE ISSUE.

A. This is an issue that arose out of the transmission rate Utah Power and Light ("UP&L") charges the Western Area Power Administration ("WAPA"). In the Final Order in Docket No. 99-035-10, the Utah PSC recounted the history of this adjustment:

> In 1962, UP&L entered into a fixed-rate contract of 80 years duration with the United States Bureau of Reclamation (later the Western Area Power Administration, WAPA), to wheel Colorado River Storage Project (CRSP) power over the Company's transmission system to public power "preference" customers. Some years later, Utah Power purchased CP National Corporation's Utah system, and thereby acquired a wheeling contract between CP National and the Bureau of Reclamation, having the same purpose and wheeling rate as the Utah Power contract. The wheeling rate in these contracts is $4.20 per kiloWatt-year; neither permits escalation.
>
> In Docket No. 82-035-13, Report and Order issued May 23, 1983, this Commission recognized that the contracts were not compensatory and ordered an imputation of revenues, based on the then-current Federal Energy Regulatory Commission (FERC) wheeling rate of $24.12, to prevent the subsidy that otherwise would flow from Utah Power's retail customers to CRSP preference customers. Revenue imputation for these WAPA contracts has been the Commission's policy since then.

<u>Re PacifiCorp</u>, UPSC Docket No. 99-035-10, Final Order at 23 (May 24, 2000). Based on the same order, the Utah Commission determined that the lack of price escalators in an 80-year contract was imprudent. Thus, it imputed revenue to the contract based on the current FERC wheeling rate. The Company has filed some of its cases in Utah with this adjustment included as one of its pro-forma adjustments. However, in the most recent two cases, it did not include the adjustment. Certain Utah parties raised the issue in their testimony and during

settlement negotiations. However, the ultimate resolution of this issue in the last two Utah cases is opaque because they were "black box" settlements. Imputing additional revenues based on the FERC wheeling rate remains the precedent of the Utah Commission and it has never been overturned, irrespective of how the Company chose to file its recent cases.

Q. DID THE OREGON COMMISSION MAKE A SIMILAR FINDING?

A. Yes. In Order No. 01-787 in Docket No. UE 116, the Oregon Commission stated as follows:

> We hold that an adjustment needs to be made for the WAPA wheeling contracts. . . .
>
> It is reasonable to presume from this evidence that by using the Utah formula with the current FERC wheeling rate, the Oregon adjustment should be \$2 million. We adopt this amount as the adjustment to be made regarding these wheeling contracts.

Re PacifiCorp, OPUC Docket No. UE 116, Order No. 01-787 at 37-38 (Sept. 7, 2001). As in Utah, many aspects of the past several Oregon cases have been settled, but the Commission has not stated that its position regarding this issue has changed since UE 116. There is simply no basis to assume that the Commission has changed its views on this matter.

Q. DID THE COMPANY FILE THIS CASE CONSISTENT WITH THE UE 116 PRECEDENT?

A. No. Based on PacifiCorp's Response to ICNU data request ("DR") No. 3.10, application of the Utah formula for this test year would result in an additional disallowance in the amount shown on Table 1. Exhibit ICNU/118 provides the details of this calculation.

Q. IN PACIFICORP'S RESPONSE TO ICNU DR NO. 3.11, THE COMPANY SUGGESTS THAT IT DISAGREES WITH THIS ADJUSTMENT FOR OREGON IN PART BECAUSE PACIFICORP CLAIMS THAT IT WOULD BE MORE APPROPRIATE TO REMOVE ALL INVESTMENTS, COSTS, AND REVENUES ASSOCIATED WITH THIS CONTRACT. PLEASE COMMENT.

A. In effect, the Company is suggesting that WAPA should be identified as a separate class of service with specific assignments of transmission plant allocated to that customer. There is simply no basis for such an assumption. Under the logic of the Revised Protocol, which uses a Rolled–in allocation factor for transmission costs, it makes no sense to isolate a single customer in this manner. Rather, the cost of the contract would be the average cost of transmission on the system. This has been measured by use of the FERC wheeling tariff in the past, and it remains a valid benchmark today.

<u>SB 1149 Costs</u>

Q. IS THE COMPANY REQUESTING RECOVERY OF COSTS RELATED TO IMPLEMENTATION OF SB 1149?

A. Yes. Pro-forma adjustment 4.15 on PPL/901 includes $1.4 million of costs related to SB 1149 implementation. These costs are allocated 100% to Oregon. Based on the information shown on PPL/901 and Mr. Wrigley's testimony, the expenses requested appear to be on-going levels. PPL/900, Wrigley/22.

Q. DESCRIBE SB 1149.

A. SB 1149 required PacifiCorp to establish a direct access program for large nonresidential customers to have the option to "shop" for an electrical supplier. It was an attempt by the legislature to promote competition in retail electrical service markets.

Q. HAS THERE BEEN SUBSTANTIAL PARTICIPATION IN DIRECT ACCESS?

A. No. Participation has been quite limited for PacifiCorp. Very few large customers find this an attractive option. ICNU has addressed this problem in prior cases and will not belabor the point here. However, ICNU believes that Commission decisions in UM 1183 and UE 170 have failed to develop a workable Transition Adjustment Mechanism. Essentially, direct access customers do not receive the full value of the resources used to serve them and are penalized if they select an alternate energy supplier. Generally, this has lead to a lack of participation in direct access in PacifiCorp's service territory.

Q. GIVEN THESE CIRCUMSTANCES, DOES THE LEVEL OF SB 1149 COSTS REQUESTED BY THE COMPANY APPEAR REASONABLE?

A. No. Given the very limited participation, these costs seem excessive. I recommend that the Commission disallow these costs unless the Company can demonstrate in its rebuttal testimony that these expenditures are necessary and reasonable, given current and expected participation in direct access. The total amount of disallowing these costs on an Oregon basis is $1.4 million.

Hybrid Comparator

Q. WHAT IS THE PURPOSE OF THE HYBRID COMPARATOR FILED BY THE COMPANY IN PPL/901, TAB 9B?

A. This analysis is intended to provide a comparator to the Revised Protocol methodology. According to the Company, it demonstrates that compared to Hybrid Method, the Revised Protocol saves Oregon ratepayers $46 million for the 2007 Test Year. PPL/901, tab 9b.

The Commission ordered PacifiCorp to develop a "fully functional" Hybrid Method when it adopted the Revised Protocol in Order No. 05-021 in Docket No. UM 1050:

> We direct PacifiCorp to include a fully developed Hybrid Method as one of options for structural protection in this report. To accomplish this, PacifiCorp should work with parties from Oregon and those interested from other states. This Hybrid Method should be designed to meet the three original Commission goals in Order No. 02-193. Once completed, the participating Oregon parties are to present the Hybrid Method to the Commission no later than December 1, 2005.
>
> Furthermore, while the Revised Protocol uses the Modified Accord as a comparator for the Revised Protocol, we want to also use the Hybrid Method as a comparator. Therefore, upon approval of the agreed-upon Hybrid Method, or January 1, 2006, whichever comes first, PacifiCorp must file its annual reports and general rate case filings comparing results under the Revised Protocol with both Modified Accord and Hybrid Method results.

Re PacifiCorp, OPUC Docket No. UM 1050, Order No. 05-021 at 12 (Jan. 12, 2005).

Q. DO YOU BELIEVE THE RESULTS OF THE COMPANY'S "HYBRID" ANALYSIS ARE REASONABLE?

A. No. These results are not indicative of a true Hybrid Method, and instead present a false comparison. Further, the Hybrid Method presented by the Company fails to achieve the Commission's goals from UM 1050. The Hybrid Workgroup did not develop a functioning Hybrid Method, but rather turned the Hybrid Method into a distorted version of Hybrid "reverse engineered" to replicate results of the Revised Protocol. Significant changes to the resource assignments in the original Hybrid Method were made without supporting evidence. This was done in order to make the New Hybrid Method more acceptable to the representatives in

PacifiCorp's eastern states and to reduce the differences between the Hybrid Method and the Revised Protocol. In the end, the new analysis is obviously flawed, and the result (the Revised Protocol resulting in $46 million in "savings" to Oregon) is counterintuitive. It also contradicts the results of the various projections presented by the Company in support of this new methodology in its November 2005 Hybrid Report.

Q. DO ANY PARTIES SUPPORT THE NEW HYBRID METHOD?

A. No, to my knowledge, neither the OPUC Staff, nor the Company, nor any other party in any state believes the New Hybrid Method is a reasonable cost allocation method.

Ironically, although many of the changes proposed by the representatives of the eastern states were incorporated into the New Hybrid Method, this methodology remains unacceptable to those states. The representatives from the eastern states promoted changes due to a concern that the Hybrid Method would eventually be utilized as a substitute for the Revised Protocol. As noted in Hybrid Report of November 2005, all parties agree that the New Hybrid Method failed to meet the original Oregon Commission goal of developing a hybrid methodology acceptable to all the states.

Q. IS THE NEW HYBIRD METHOD USEFUL TO THE COMMISSION?

A. No. The attempt to devise a New Hybrid Method that Idaho, Utah, and Wyoming found moderately "less offensive" frustrated the two objectives clearly articulated by the Commission. First, the New Hybrid Method is not a useful tracking tool. This is because parties (except for ICNU) agreed to a re-assignment of certain resources simply as a means of producing results that are as close as possible to the Revised Protocol. Consequently, any benefit as a tracking tool was lost from the start. Second, the validity of the Hybrid Method as a Structural Protection Mechanism ("SPM") was undermined by reassignment of the costs of an eastern 2014 combined cycle plant to the western control area. Again, there was complete agreement by all parties to the Hybrid and Load Growth workshop that the New Hybrid Method was not a useful SPM.

Q. DISCUSS THE PROBLEMS WITH THE NEW HYBRID METHOD.

A. In the original Hybrid Method, the APS Exchange contract and the Cholla Plant were assigned to the eastern control area. These resources are interconnected to the eastern control area. However, the New Hybrid Method assigns the APS contract to the west, but Cholla to the east. Historically, the exchange contract and the Cholla resource were linked. While the assignment of both APS and Cholla to the west was considered, it was rejected because the results were not agreeable to the eastern states. The final assignment of Cholla to the east and APS to the west provides particularly unfavorable results for the west, but was adopted in order to produce results closer to the Revised Protocol.

The assignment of the APS contract to the western control area is inconsistent with the way PacifiCorp operates its system. For example, a review of the GRID transmission topology shows that this is inappropriate. Specifically, APS and Cholla are located far to the southeastern side of the system, and there is no way that the loads or resources in the western control area have any real connection with Cholla or the exchange transaction.

Q. ARE THESE THE ONLY QUESTIONABLE RESOURCE ASSIGNMENTS IN THE NEW HYBRID METHOD?

A. No. The model also assigns 125 MW of Jim Bridger to the east. The assignment of 125 MW of Bridger to the eastern control area is also result oriented. Bridger was originally a Pacific Power & Light resource and is located in the western control area. Further, Bridger itself is not directly connected to Utah because any power from Bridger must flow to Wyoming first before being transferred to Utah. As a result, this flow of power seems unlikely.

Q. ARE THERE OTHER PROBLEMS WITH THE ANALYSIS IN PPL/901, TAB 9B?

A. It appears that the various questionable resource assignments, or other modeling infirmities, have produced some very unexpected results. While Table 2 in the November 2005 Hybrid report showed only a negligible NPV difference in cost to Oregon between the New Hybrid Method and the Revised Protocol (-.09% difference NPV$ 2007-2020), the actual result, $46 million, is quite substantial. This indicates that either the original modeling studies were seriously flawed, or that the unexpected changes in fuel and power prices have made this New Hybrid Method particularly unattractive for Oregon. In contrast, the original Hybrid Method, as updated in July 2003, predicted NPV savings to Oregon of 3.2% for the period 2007 to 2020. ICNU/119 (November 2005 Hybrid Report Table 2). This reversal from savings in the original projections, to a substantial cost increase in the current test year analysis, clearly indicates that the New Hybrid Method is simply not a useful tool for Oregon to rely upon. If the original studies underlying the various adjustments to Hybrid were flawed, as compared to an actual rate case analysis, then there is no basis for assuming the changes to the model were reasonable.

Q. IN DOCKET UM 1050 YOU PRESENTED AN ANALYSIS OF THE AVERAGE RATE PER KWH FOR OREGON AND UTAH FOR THE PERIOD 1988 (PRE-MERGER) TO 2002. THE PURPOSE OF THIS ANALYSIS WAS TO PROVIDE A "COMPARATOR" BASED ON CUSTOMER RATES. IF ONE UPDATES THESE FIGURES DO THE CONCLUSIONS CHANGE?

A. No. The updated average rate analysis is presented in Exhibit ICNU/120. I have included average price data for 2003 through 2005. This data was obtained from the Department of Energy ("DOE") Energy Information Administration ("EIA") Form 861 and ICNU 17.15. The EIA 861 is an official document published by EIA, based on annual submissions by electric utilities, and it represents the most recent data available from EIA. The EAI and discovery data spans the period prior to the merger of the systems to the most recent year available, 2005.

As was the case at the time of UM 1050, there is prima facie evidence that the merger between PP&L and the higher cost UP&L system has had a detrimental effect on the rates of Oregon customers. The exhibit shows a series of graphs and tables depicting the trend in average rates for PP&L and UP&L customers in Oregon and Utah over the period 1988 to 2005.

The EIA data shows that in 1988, UP&L in Utah had average rates 34% higher (for all customer classes) than PP&L did in Oregon. Utah's residential rates were 56% higher, and Utah's industrial rates were 19% higher than Oregon's. From 1988 to 2005, Oregon's average rates for all classes have <u>increased</u> by 16.7% while Utah's average rates <u>decreased</u> by 11.0%. Currently, the composite average rate for all customer classes is within 2% for Oregon and

Utah. Industrial rates are essentially equal in Utah and Oregon. The substantial rate advantage enjoyed by Oregon before the merger has now been eliminated.

Clearly, this data strongly suggests that through the many years of compromise and negotiation, Oregon has lost ground while Utah has gained ground. The latest Hybrid analysis clearly demonstrates this fact. A method originally supported by Oregon parties because it was believed to be a more accurate representation of the dual control area nature of the system and preferable to Oregon, now produces results far less favorable to the state. This is apparently due to the many compromises made during the 2005 Hybrid workshops.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the Commission reject the filed Hybrid study as a comparator to judge the reasonableness of the Revised Protocol. I recommend the Commission send the Company "back to the drawing board" with direction to establish a more straightforward analysis, which focuses solely on resources required to serve Oregon. The Company has already been directed to perform such an analysis for Washington as one of the outcomes of the 2005 general rate case in that state. WUTC v. PacifiCorp, WUTC Docket No. UE-050684, Order 04 at ¶¶ 62-70 (Apr. 17, 2006). It should not be difficult to devise a model applicable to both states. Because the projections relied upon in development of the New Hybrid Method have proven so inaccurate, I believe it is fair to question the entire modeling approach used by the Company. For this reason, development of a simpler method would be much more preferable.

Q. SHOULD THE COMMISSION DIRECT THE COMPANY TO HOLD NEW WORKSHOPS WITH PARTICIPATION FROM OTHER STATES IN THIS PROCESS?

A. No. That process failed to produce a useful model for Oregon and failed to produce any consensus among the parties. There is no benefit in repeating it.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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ICNU/117

GENERATION OVERHAUL ADJUSTMENT

July 12, 2006

Item	ICNU	Company	Adjustment	Allocator	Oregon Allocated
Steam Account 514 SG	6,966,637	17,337,549	-10,370,912	26.63%	-$2,761,566
Steam Account 514 SSGCH	-3,838,845	-4,631,595	792,750	27.56%	$218,506
Hydro (East) 514 SG-U	0	612,450	-612,450	26.63%	-$163,083
Hydro (West) 545 SG-P	0	478,750	-478,750	26.63%	-$127,482
Other Generation 554 SG (Incl. Currant Cr.)	3,479,740	3,209,740	270,000	26.63%	$71,896
Other Generation 554 SSGCT	0	771,000	-771,000	25.54%	-$196,929
	Total	**17,777,894**	**-11,170,362**		**-2,958,659**

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ICNU/118

WAPA WHEELING ADJUSTMENT

July 12, 2006

Exhibit ICNU/118
WAPA Wheeling Adjustment

Line No.	Description	Acct.	Total Company	Factor	Factor %	Oregon Allocation
	Adjustment to Expense:					
1	Adjustment to WAPA Wheeling Revenues	456	3,135,903	SG	26.628%	835,028
	Adjustment Detail:			Peak KW	Revenues	
	Actual WAPA KWH and billed revenues (12 months 6/30/04)					
2	Contract (2436)			2,589,767	$ 2,108,376	
	Imputed revenue using current FERC tariff price:					
3	Peak KWH		2,589,767			
4	Monthly Price (Annual price $24.30)		$2.0250			
5	Imputed Revenues		5,244,278		5,244,278	
	Discounted Revenue on the WAPA Contract (2436 only) for 12 months					
6	ended Dec 31, 2004				3,135,903	

Description of Adjustment:

This adjustment increases jurisdictional revenues as previously ordered by the Utah Commission consistently since 1983 for the WAPA Contract. Also adopted by the Oregon Commisison in UE 116

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(dba PACIFICORP)	)
	)
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ICNU/119

HYBRID REPORT TABLE 2 (NOV. 21, 2005)

July 12, 2006

Oregon. The shaded columns highlight the results that reflect the Hybrid presented in this Hybrid Report as a reporting comparator for use in Oregon.

Table 2
Updated July 2003 Hybrid and Hybrid
Percentage Difference in NPV Revenue Requirement
from Revised Protocol

	Updated July 2003 Hybrid (*)	Hybrid (#)	
State	14-Year NPV @ 8.4277% Fiscal Years 2007-2020	9-Year NPV @ 8.4277% Fiscal Years 2007-2015	14-Year NPV @ 8.4277% Fiscal Years 2007-2020
California	-4.80%	- 0.15%	- 0.21%
Oregon	-3.21%	0.03%	- 0.09%
Washington	-2.58%	0.14%	- 0.03%
West Control Area	-3.18%	0.04%	- 0.08%
Utah	1.65%	- 0.08%	0.04%
Idaho	1.08%	- 0.69%	- 0.68%
Wyoming	3.00%	0.54%	0.43%
East Control Area	1.84%	- 0.02%	0.05%

(*) also known as Hybrid Case 2, and consistent with the Company's 2004 IRP Report
(#) also known as Hybrid Case 3b1a, and consistent with the Company's 2004 IRP Report

As can be seen in the table above, the modifications and added components brought the results, for all States, closer to the Revised Protocol. As shown in the results above, the West Control Area moved from approximately 3% below Revised Protocol (14-Year NPV) to less than 0.1% below Revised Protocol (14-Year NPV). In comparison, the East Control Area moved from approximately 2% above Revised Protocol (14-Year NPV) to less than 0.1% above Revised Protocol (14-Year NPV).

Section 5 provides a detailed description of the Hybrid, presented in this Hybrid Report as a reporting comparator for use in Oregon, and **Section 6** provides an explanation of the results of the Hybrid, with particular emphasis on the results for the West Control Area, East Control Area and Oregon. **Section 7** provides a discussion of the concerns that continue to exist with the Hybrid and its methodology.

4.2 Formation of the Hybrid Workgroup

In February 2005, the Company scheduled a meeting with Oregon parties (and other interested parties from the States of Idaho, Utah, Washington and Wyoming) to review Oregon Order No. 05-21 and discuss how to meet its conditions. At the

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ICNU/120

PRE AND POST MERGER TREND IN RATES

July 12, 2006

Exhibit ICNU/120
Pre and Post Merger Trend in Rates
Average Revenue per kWh - Oregon and Utah 1988-2005
Source: DOE Energy Information Administration Form 861* and ICNU 17.15

	========Oregon Customer Avg. Cents/kWh=======				=========Utah Customer Avg. Cents/kWh=========			
	Residential	**Commercial**	**Industrial**	**All Customers**	**Residential**	**Commercial**	**Industrial**	**All Customers**
1988	5.29	5.09	3.78	4.72	8.26	7.32	4.50	6.33
1989	5.24	5.18	3.74	4.70	7.79	6.92	3.96	5.76
1990	5.21	5.09	3.74	4.67	7.38	6.27	3.72	5.38
1991	5.16	5.08	3.76	4.67	7.34	6.08	3.79	5.37
1992	5.20	5.07	3.85	4.71	7.09	5.89	3.63	5.14
1993	5.28	5.07	3.89	4.76	7.00	5.83	3.69	5.16
1994	5.50	5.02	3.87	4.80	6.99	5.79	3.76	5.20
1995	5.53	4.94	3.85	4.79	7.00	5.80	3.65	5.12
1996	5.76	5.18	3.91	5.00	7.00	5.79	3.57	5.10
1997	5.97	5.25	3.83	5.05	6.93	5.60	3.40	4.98
1998	6.15	5.33	3.74	5.09	6.87	5.59	3.37	4.97
1999	6.23	5.39	3.94	5.26	6.18	5.08	3.27	4.63
2000	6.41	5.43	4.20	5.42	6.19	4.97	3.25	4.59
2001	6.52	5.51	4.66	5.64	6.60	5.25	3.36	4.91
2002	6.40	5.67	4.11	5.55	6.60	5.21	3.69	5.06
2003	6.37	5.68	4.10	5.58	6.66	5.26	3.59	5.03
2004	6.24	5.51	4.02	5.46	7.06	5.61	3.86	5.35
2005	6.31	5.56	4.01	5.51	7.41	5.89	4.01	5.63
1988-2005 % Change	**19.4%**	**9.3%**	**6.2%**	**16.7%**	**-10.2%**	**-19.5%**	**-10.9%**	**-11.0%**

* Annual Data Supplied to EIA by PacifiCorp, Utah Power & Light and Pacific Power & Light

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

DIRECT TESTIMONY OF

MICHAEL P. GORMAN

ON BEHALF OF

THE CITIZENS' UTILITY BOARD AND

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

July 12, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. WHAT IS YOUR OCCUPATION?

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. These are set forth in Exhibit CUB-ICNU/401.

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

A. I am appearing on behalf of the Citizens' Utility Board ("CUB") and the Industrial Customers of Northwest Utilities ("ICNU").

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

A. I will recommend an appropriate capital structure, a fair return on common equity, and an overall rate of return for PacifiCorp.

Q. PLEASE SUMMARIZE YOUR RATE OF RETURN RECOMMENDATIONS.

A. I recommend the Public Utility Commission of Oregon ("Commission") award PacifiCorp a return on common equity of 9.8% and overall rate of return of 8.05%, as shown on my Exhibit CUB-ICNU/402. My return on common equity recommendation would result in a $30 million reduction to PacifiCorp's filed revenue requirement.

I recommend the rejection of PacifiCorp's projected capital structure. The Company's projected capital structure is overweighted with common equity and therefore is too expensive and unreasonable for rate setting purposes. I recommend a capital structure composed of 48.9% equity, 1.1% preferred stock, and 50.0% debt be used to develop PacifiCorp's overall rate of return in this proceeding. Adoption of the recommended capital structure would reduce PacifiCorp's requested revenue requirement by $10 million. In total, my proposals would reduce PacifiCorp's revenue requirement by $40 million.

My recommended return on equity for PacifiCorp is based on constant growth Discounted Cash Flow ("DCF"), Risk Premium ("RP"), and Capital Asset Pricing Model ("CAPM") analyses.

I demonstrate that my recommended return on equity and proposed capital structure for PacifiCorp will provide PacifiCorp an opportunity to realize cash flow financial coverages and a balance sheet strength that conservatively support PacifiCorp's current bond rating. Consequently, my recommended return on equity represents fair compensation for PacifiCorp's investment risk and will preserve PacifiCorp's financial integrity and credit standing.

I respond to PacifiCorp witness Dr. Samuel Hadaway's recommended 11.5% return on equity. Dr. Hadaway estimates PacifiCorp's return on equity to be 11.0% and he proposed a 0.5% add-on to reflect PacifiCorp's alleged higher risk. Dr. Hadaway's 11.0% return on equity is overstated because his risk premium reflects an unreasonable adjustment to historical risk premium numbers and his growth rate is excessive and significantly overstates consensus market participants' assessment of future growth of utility stocks and the overall U.S. economy in general. Dr. Hadaway's proposed 0.5% PacifiCorp risk premium should be rejected because it is flawed, unjust, and unreasonable. Reasonable data inputs to Dr. Hadaway's own models would reduce his return on equity estimates and support a return on equity consistent with my recommended 9.8% return on equity.

ELECTRIC UTILITY INDUSTRY MARKET PERSPECTIVE

Q. PLEASE DESCRIBE THE MARKET'S PERCEPTION OF THE ELECTRIC UTILITY INDUSTRY OVER THE LAST SEVERAL YEARS.

A. I believe Standard & Poor's ("S&P") captures the sentiment of the investment market toward the electric utility industry experienced over the last several years. In 2001, S&P stated it recorded 81 downgrades to utility credit ratings, with only 29 upgrades. S&P stated in 2002 that the credit rating activity in the electric utility industry was negative due to: 1) weakening financial profiles; 2) loss of investor confidence which affected the industry's liquidity and financial flexibility; 3) heightened business risk derived from more investments outside the traditional regulated utility business; 4) corporate restructuring and mergers and acquisitions; and 5) certain regulatory difficulties.

S&P attributed most of the 2002 liquidity and credit erosion in the industry to heavy debt-funded investments in higher risk non-regulated activities, and the loss of management credibility due to accounting and trading irregularities. Exhibit CUB-ICNU/403, Gorman/2-9 (S&P Utilities & Perspectives, Global Utilities Rating Service (Oct. 14, 2002)).

Importantly, this negative perception of the energy industry over the last several years has been improved considerably because the industry has reverted to a "back to basics" business model. As part of the back to basics business model, utilities have been shedding non-regulated activities and using the asset sale proceeds to retire debt. Also, utilities have adopted corporate governance policies that have helped regain the confidence of the market.

In 2005, S&P revised its industry outlook by stating that the industry's leading indicators of credit rating trends show that there are nearly twice as many stable outlooks as negative outlooks. S&P credits this improved credit quality and liquidity enhancement to improving credit rating metrics resulting primarily from a reduction of high cost debt and elimination of higher risk non-utility investments, and the industry's shift to a back to basics business model, which concentrates on core competencies, debt reduction and risk management. Exhibit CUB-ICNU/403, Gorman/10-11 (S&P: Industry Report Card: U.S. Electric/Water/Gas (Jan. 4, 2005)).

PROJECTED INTEREST RATES AND CAPITAL MARKET COSTS

Q. SHOULD THE COMMISSION FOLLOW THE LEAD OF DR. HADAWAY AND PLACE HEAVY RELIANCE ON PROJECTED INTEREST RATES AND FUTURE CAPITAL MARKET COSTS RELATIVE TO TODAY'S OBSERVABLE CAPITAL MARKET COSTS?

A. No. While projected interest rates should be given some consideration, the determination of PacifiCorp's cost of capital today should be based primarily on observable and verifiable actual current market costs. This is appropriate because projected changes to interest rates are uncertain and the accuracy is at best problematic. Indeed, this is clearly evident by a review of projected changes to interest rates made over the last five years, in comparison to how accurate these projections turned out to be. This analysis clearly illustrates that observable interest rates today are as accurate as economists' consensus projections of future interest rates.

An analysis supporting this conclusion is illustrated on my Exhibit CUB-ICNU/404. On this exhibit, under Columns 1 and 2, I show contemporary market yields and projected Treasury bond yields two years in the future. In Column 1, I show the Treasury yield. In Column 2, I show the projected yield two years out. As shown in

Columns 1 and 2, over the last five years Treasury yields were projected to increase relative to the current Treasury yields at the time of the projection. The projected yield change is shown under Column 5. In Column 4, I show what the Treasury yield actually turned out to be two years after the forecast. Under Column 6, I show the actual yield change from the time of the projections.

As shown on Exhibit CUB-ICNU/404, over the last five years economists have consistently been projecting increases to interest rates. However, as demonstrated under Column 6, those yield projections have turned out to be overstated in virtually every case. Indeed, Treasury yields have actually decreased or remained flat over the last five years, rather than increase as the economists' projections indicated.

This review of the experience with projected interest rates illustrates that interest rate projection accuracy is highly problematic. Indeed, current observable interest rates are just as likely a reasonable projection of future interest rates as are economists' projections. Accordingly, while I will use projected interest rates to provide some sense of the market's expectations of future capital market costs in my models, I will not use them exclusively. Rather, my analyses will be based on the combination of current observable interest rates and projected interest rates. Thus, my analyses will capture a return on equity range reflecting a broad range of potential actual capital market costs during the period rates will be in effect.

PACIFICORP'S PROPOSED CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE IS THE COMPANY REQUESTING TO USE TO DEVELOP ITS OVERALL RATE OF RETURN FOR ELECTRIC OPERATIONS IN THIS PROCEEDING?

A. PacifiCorp's proposed capital structure is shown below in Table 1.

TABLE 1

PacifiCorp's Proposed Capital Structure (March 31, 2007)

Description	Percent of Total Capital
Common Equity	52.8%
Preferred Equity	1.0%
Long-Term Debt	46.2%
Total Financial Capital Structure	100.0%

Source: PPL/300, Williams/3.

PacifiCorp's proposed capital structure reflects $500 million of parent company common equity infusions for FY 2006, and reflects a projected $525 million of equity infusions in FY 2007, based on the Company's budgeted quarterly cash contributions of $131.25 million in that fiscal year.

Q. WHY IS PACIFICORP REFLECTING AN ADDITIONAL $525 MILLION OF EQUITY CONTRIBUTIONS IN FY 2007?

A. PacifiCorp witness Mr. Williams states the following reasons in support of the additional equity contributions.

1. The Company's budget reflects significant cost increases including investments in utility plant and other activities.

2. Due to increasingly more rigorous expectations of credit rating agencies for credit metrics and balance sheet strength to support the Company's current "A-" credit rating from S&P and Moody's and to prevent tradings from further downgrading PacifiCorp.

3. The projected capital structure makes PacifiCorp's capital structure weights comparable to the proxy utility group Dr. Hadaway used for estimating PacifiCorp's return on equity.

Q. IS THE COMPANY'S PROPOSED CAPITAL STRUCTURE FOR SETTING RATES REASONABLE?

A. No. PacifiCorp's FY 2007 budgeted capital structure, along with the budgeted equity contributions results in an excessively weighted common equity capital structure, which unnecessarily increases the Company's revenue requirement and claimed revenue deficiency, and is not needed to support its current "A-" senior secured bond rating and "BBB+" unsecured bond rating from S&P.

Q. DID MR. WILLIAMS IDENTIFY OR PROVIDE SPECIFIC EVIDENCE FROM S&P, MOODY'S OR FITCH IN SUPPORT OF THE NEED TO INCREASE THE COMMON EQUITY RATIO TO PRESERVE PACIFICORP'S CURRENT BOND RATING?

A. No.

Q. WHY DO YOU BELIEVE AN INCREASE IN THE COMMON EQUITY RATIO AS PROPOSED BY THE COMPANY IS NOT NEEDED TO SUPPORT PACIFICORP'S CURRENT BOND RATING?

A. In supporting the Company's current bond rating, I first want to clearly distinguish what the Company's current credit rating is. PacifiCorp's senior secured S&P bond rating is "A-," and its unsecured S&P bond rating is "BBB+." This is significant because a large portion of the Company's financial obligations is based on off-balance sheet ("OBS") debt equivalence from purchased power agreements ("PPAs"). These PPA OBS are subordinated debt obligations, which are distinguished by S&P and the other credit rating agencies in assessing the credit strength and default risk of PacifiCorp's senior secured debt, in comparison to its total debt.

PacifiCorp's proposed total debt ratio for ratemaking purposes is 46.2%. This compares to a benchmark S&P publishes both PacifiCorp's current business profile score of 5, to maintain a total debt ratio in the range of 42% to 50% for a single "A" bond rating and 50% to 60% for "BBB" bond rating. Accordingly, for PacifiCorp's current "A-" secured bond rating, and "BBB+" unsecured bond rating, PacifiCorp's actual FY06 total debt ratio of 50% will support PacifiCorp's current weak "A" (i.e., or "A-") credit rating, and strong "BBB" (i.e., or "BBB+") bond rating.

As discussed in more detail below, when off-balance sheet debt equivalents are included with PacifiCorp's FY06 actual capital structure, PacifiCorp's adjusted total debt ratio would be approximately 53.0%, which is below the midpoint of S&P's benchmark for a "BBB" rated utility company, and thus supportive of an unsecured bond rating of "BBB+." Since OBS debt is a subordinated debt obligation, it should not have significant erosion to the senior secured credit rating of PacifiCorp, but it is necessary to review the overall corporate credit rating, which includes unsecured debt obligations. In significant contrast, PacifiCorp's proposed capital structure composed of 46.2% debt is too far below this criterion.

Q. DO THE CREDIT RATING REPORTS PROVIDED BY THE COMPANY SUGGEST A NEED TO INCREASE ITS EQUITY RATIO AND REDUCE DEBT LEVERAGE TO SUPPORT PACIFICORP'S CURRENT CREDIT RATING?

A. No. Recent credit rating reports from both S&P and Moody's do not cite a need to reduce PacifiCorp's current leverage to support its current ratings. However, although both rating agencies are concerned about how the growth in PacifiCorp's regulated rate base will be financed, they do <u>not</u> state a need to increase the percentage of equity to total capital. As such, maintaining the FY06 capital structure mix of 48.9% common equity, 1.1% preferred stock, and 50% long-term debt is supportive of PacifiCorp's current bond ratings.

For example, a March 6, 2006 report by Moody's Investors Service, Moody's rates PacifiCorp's outlook as stable and issued a rating of "Baa1," and a first mortgage bond rating of "A3." In characterizing PacifiCorp's credit rating as "stable," Moody's stated as follows:

> The Baa1 senior unsecured rating of PacifiCorp reflects expected credit metrics that are consistent with a Baa1 rating for a vertically integrated utility with PacifiCorp's risk profile under Moody's industry rating methodology (please refer to Rating Methodology: Global Regulated Electric Utilities, March 2005) and in comparison to similar companies. Key financial metrics include the ratio of adjusted funds from operations (FFO) to total adjusted debt that has averaged about 19% for the past three years, and the ratio of FFO to interest expense that has averaged about 4.0x during the same period.

Exhibit CUB-ICNU/403, Gorman/13 (Moody's Investors Service, Global Credit Research (Mar. 1, 2006)). As I will note later, the funds from operations coverages implicit with my proposed capital structure and return on equity are consistent with Moody's objectives for PacifiCorp.

Further, in discussing credit rating facts for MidAmerican's acquisition of PacifiCorp, S&P stated the following concerning MEHC's respective efforts to maintain PacifiCorp's credit quality:

> Standard & Poor's expects that MEHC will deleverage PacifiCorp through the reinvestment of cash flow into its extensive capital expenditure program. MEHC has represented that it views a properly capitalized utility as having roughly a 50-50 equity-to-debt structure, and it has achieved this at MEC. The dividend restrictions in place as a part of regulatory approval should also provide incentives to deleverage PacifiCorp.

Exhibit CUB-ICNU/403, Gorman/24 (S&P Credit FAQ: MidAmerican's Acquisition of PacifiCorp – Implications for PacifiCorp's Bondholders (Mar. 21, 2006)). Accordingly, maintaining a capital structure reasonably consistent with PacifiCorp's FY06 actual capital structure (including a 50/50 debt to equity capital structure) is supportive of its current bond rating.

Also, the FY06 capital structure is supportive of the rate settlement entered into by multiple stakeholders in MEHC's proposed acquisition of PacifiCorp. In that settlement, PacifiCorp pledged to maintain a common equity ratio of 48.25% initially after the acquisition, with the equity ratio remaining above 44% over time.

Q. WHAT ADJUSTMENTS DO YOU PROPOSE TO PACIFICORP'S CURRENT PROPOSED CAPITAL STRUCTURE IN THIS PROCEEDING?

A. PacifiCorp is proposing to include a $525 million equity infusion in its capital structure to meet the capital expenditure objectives PacifiCorp has planned. This increases PacifiCorp's common equity ratio from approximately 49% up to 52.6%. I recommend that the Commission reject PacifiCorp's planned equity infusion and instead reflect $525 million of additional capital being infused into PacifiCorp in the same debt/equity mix that existed at the end of FY06. Again, as noted above, the FY06 capital structure will support PacifiCorp's current investment grade bond rating, reflects the infusion of equity to maintain that capital structure, and helps support its current construction program. Importantly, maintaining the current capital structure mix will not unnecessarily increase PacifiCorp's cost of service and revenue requirement in this proceeding by using more equity in PacifiCorp than necessary to maintain its current credit rating.

Q. SHOULD THE COMMISSION REQUIRE PACIFICORP TO PROVIDE DETAIL AND COMPLETE EVIDENCE SUPPORTING ITS CONTENTION THAT AN INCREASE TO ITS EQUITY RATIO IS NECESSARY TO MAINTAIN ITS CURRENT BOND RATING?

A. Yes. PacifiCorp and its parent company, MEHC have a conflict of interest toward maintaining an appropriate capital structure for PacifiCorp and enhancing MEHC's profits. Specifically, PacifiCorp pays dividends based on the return on equity earned on utility operations up to MEHC. MEHC could increase PacifiCorp's earnings and dividend payments by making common equity contributions to PacifiCorp, and increase its equity ratio. That, in turn, if approved by regulators, would increase PacifiCorp's retail revenue requirement and earnings entitlement, thus allowing it to pay larger dividends.

MEHC's funding for these equity contributions can be any source of capital available to MEHC, including debt capital. If MEHC funds equity contributions into PacifiCorp using debt capital, then it can arbitrage its cost of capital by paying debt interest expense on MEHC's outstanding debt and receiving an equity return on that debt via PacifiCorp's regulated cost of service. Hence, MEHC can have a conflict of interest of overstating claimed equity infusions in PacifiCorp, which can be funded by debt at MEHC.

Consequently, the Commission should require PacifiCorp to provide credible and complete evidence supporting the level of equity needed to maintain its credit rating and access to capital, and it should reject equity infusions that will unnecessarily increase PacifiCorp's revenue requirement and earnings entitlement on utility plant investments.

Q. SHOULD PACIFICORP ALSO BE OBLIGATED TO SHOW EVIDENCE THAT IT HAS CONSIDERED ALL SOURCES OF CAPITAL TO REDUCE ITS COST OF SERVICE AND MAINTAIN ITS CREDIT RATING AND ACCESS TO CAPITAL?

A. Yes. PacifiCorp likely has the option of using more permanent preferred equity securities to reduce its outstanding debt leverage and strengthen its credit rating at a lower cost of capital. Preferred equity securities are lower cost than common equity securities and can thus reduce debt leverage at a lower cost than increasing common equity capital.

As such, in supporting a need to reduce debt leverage to maintain its current credit rating, or improve its credit rating, PacifiCorp should provide a complete least cost capital structure plan for funding utility operations that should consider increasing preferred equity in order to reduce debt leverage and strengthen credit rating metrics. PacifiCorp has not provided any such analysis in this proceeding, and thus, its proposed equity infusion should be rejected until it demonstrates its proposed capital structure mix plan for PacifiCorp is consistent with its obligation to provide least cost utility service.

Q. WILL YOU PROVIDE MORE DETAILS CONCERNING THE CREDIT RATING FINANCIAL METRICS SUPPORTING AN ADJUSTED CAPITAL STRUCTURE AND RETURN ON EQUITY IN YOUR TESTIMONY?

A. Yes. This is provided in support of my recommended capital structure and return on equity later in this testimony.

Q. WHAT CAPITAL STRUCTURE DO YOU RECOMMEND BE USED TO SET PACIFICORP'S OVERALL RATE OF RETURN IN THIS PROCEEDING?

A. I recommend a capital structure composed of 50% debt, 1.1% preferred equity, and 48.9% common equity. This capital structure is reasonable for the following reasons:

1. It is reasonably consistent with the common equity target established in the stipulated settlement between the parties in the proceeding where MEHC sought Commission approval to acquire PacifiCorp. In that settlement, PacifiCorp agreed to maintain a total common equity ratio of 48.25%.

2. The capital structure is based on the actual FY06 capital structure mix, which already includes a $500 million equity infusion made into PacifiCorp by its parent company in FY06. That capital structure has been determined by credit rating agencies as supportive of PacifiCorp's current bond rating, therefore, increasing the common equity percentages is unnecessary and unjust.

3. The common equity ratio is reasonably consistent with the proxy group I will use to estimate PacifiCorp's return on equity.

4. As discussed later in this testimony, this capital structure, along with my proposed return on equity will maintain credit rating metrics that support PacifiCorp's current senior secured "A-" bond rating, and "BBB+" unsecured bond rating.

Q. WHY WOULD RELYING ON A CAPITAL STRUCTURE TOO HEAVILY WEIGHTED WITH COMMON EQUITY UNNECESSARILY INCREASE PACIFICORP'S REVENUE REQUIREMENT AND DELIVERY SERVICE RATES?

A. This happens because common equity is the most expensive form of capital, and is subject to income tax expense. Consider, for example, the difference between the revenue requirement cost of common equity and that of debt. At an authorized return of 10%, and a consolidated income tax rate of 40%, the revenue requirement cost of common equity capital would be 16.7%. In comparison, at a "BBB" bond rating, PacifiCorp's marginal cost of debt currently is about 6%. Hence, the revenue requirement cost of common equity is more than two and one-half times as expensive as that of debt. Thus, increasing the weight of common equity, and decreasing the weight of debt capital supporting the utility's delivery service rate base, will unnecessarily increase the revenue requirement.

As discussed below, an appropriate capital structure should reflect a reasonable balance of equity and debt capital. The balance should be based on the appropriate financial risk and operating risk of the underlying utility, and a capital structure that is reasonably consistent with maintaining its current or target bond rating.

COST OF DEBT

Q. HAVE YOU REVISED PACIFICORP'S COST OF DEBT TO REFLECT YOUR RECOMMENDATION TO ALLOCATE PACIFICORP'S PROPOSED $525 MILLION OF ADDITIONAL EQUITY CAPITAL TO A MIX OF DEBT AND EQUITY CAPITAL TO MAINTAIN THE SAME FY06 CAPITAL STRUCTURE?

A. No. PacifiCorp's current embedded cost of debt is 6.37% and is generally consistent with PacifiCorp's marginal cost of debt. Hence, an adjustment to PacifiCorp's embedded cost of debt to reflect increasing the amount of new debt to meet this capital funding requirement is not necessary because it would result in approximately the same estimated embedded cost of debt.

RETURN ON COMMON EQUITY

Q. PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED COMPANY'S COST OF COMMON EQUITY.

A. In general, determining a fair cost of common equity for a regulated utility has been framed by two decisions of the U.S. Supreme Court, Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923) and Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

These decisions identify the general standards to be considered in establishing the cost of common equity for a public utility. Those general standards are that the authorized return should: 1) be sufficient to maintain financial integrity; 2) attract capital under reasonable terms; and 3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

Q. PLEASE DESCRIBE WHAT IS MEANT BY "UTILITY'S COST OF COMMON EQUITY."

A. The utility's cost of common equity is the return investors expect, or require, in order to make an investment. Investors expect to achieve their return requirement from receiving dividends and from stock price appreciation.

Q. PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE THE COST OF COMMON EQUITY FOR PACIFICORP.

A. I have used several models based on financial theory to estimate PacifiCorp's cost of common equity. These models are: 1) the constant growth discounted cash flow model ("DCF"); 2) the bond yield plus equity risk premium model; and 3) a capital asset pricing model ("CAPM"). I have applied these models to a group of publicly traded utilities that

I have determined represent the investment risk of an electric utility similar to PacifiCorp. I discuss this comparable utility group below.

Q. HOW DID YOU DEVELOP A DCF ANALYSIS AND RISK PREMIUM ESTIMATES FOR PACIFICORP?

A. I relied on the same group of electric utility companies as used by PacifiCorp witness Dr. Samuel Hadaway in his estimate of a fair return on equity for PacifiCorp. However, I excluded CH Energy and MGE Energy due to unavailable consensus growth estimates from Zack's, Reuters and Thomson Financial or FirstCall, Progress Energy because they are involved in meaningful asset sales and acquisition activity, and NSTAR because its business risk profile score of 1 is not comparable to the business risk profile score of PacifiCorp and the comparable group.

As shown below, I believe my proposed proxy group is a reasonable risk proxy for PacifiCorp. As demonstrated on my Exhibit CUB-ICNU/405, the comparable group has an average investment bond rating from S&P and Moody's of "A-" and "A3," respectively. It has a common equity ratio of 48% from Value Line, and a common equity ratio of 45% from AUS Utility Reports. This compares to a 49% common equity ratio I proposed for PacifiCorp. While my proxy group has slightly more financial risk as evidenced by a slightly lower common equity ratio than my proposed capital structure for PacifiCorp, its business risk is slightly lower as demonstrated by a somewhat lower S&P business profile score than PacifiCorp. The average business profile of the electric comparable group is 4, which is slightly below the business profile of PacifiCorp of 5. On the basis of total risk, I believe PacifiCorp's combination of financial and operating risk is reasonably comparable to my proxy group.

DISCOUNTED CASH FLOW MODEL

Q. PLEASE DESCRIBE THE DCF MODEL.

A. The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return ("ROR") or cost of capital. This model is expressed mathematically as follows:

$$Po = \frac{D1}{(1+K)^1} + \frac{D2}{(1+K)^2} \; .\,.\,.\,. \; \frac{D\infty}{(1+K)\infty} \quad \text{where} \qquad \text{(Equation 1)}$$

Po= Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor required return, "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D1/Po + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D1 = Dividend in first year
Po = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the "constant growth" annual DCF model.

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A. As shown under Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

Q. WHAT STOCK PRICE AND DIVIDEND HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A. I relied on the average of the weekly high and low stock prices over a 13-week period ending June 2, 2006. An average stock price is less susceptible to market price variations than is a spot price. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not be reflective of the stock's long-term value.

A 13-week average stock price is short enough to contain data that reasonably reflects current market expectations, but is not too short a period to be susceptible to market price variations that may not be reflective of the security's long-term value. Therefore, in my judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and to capture sufficient data to smooth out aberrant market movements. I used the most recently paid quarterly dividend, as reported in the Value Line Investment Survey. This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D1 factor for use in Equation 2 above.

Q. WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR DCF MODEL?

A. There are several methods one can use in order to estimate the expected growth in dividends. However, for purposes of determining the market required return on common equity, one must attempt to estimate what the consensus of investors believe about the dividend or earnings growth rate, and not what an individual investor or analyst may use to form individual investment decisions.

Security analysts' growth estimates have been shown to be more accurate predictors of future returns than growth rates derived from historical data[1/] because they are more reliable estimates, and, assuming the market generally makes rational

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[1/] See, e.g., David Gordon, Myron Gordon, and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989.

investment decisions, analysts' growth projections are the most likely growth estimates that are built into stock prices.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for the investor consensus dividend growth rate expectations. I used the average of three sources of customer growth rate estimates, including Zack's Advisor, Reuters, and Thomson Financial or First Call. All consensus analyst projections used were available on June 6, 2006, as reported on-line. Each consensus growth rate projection is based on a survey of security analysts. The consensus estimate is a simple arithmetic average or mean of surveyed analysts' earnings growth forecasts. A simple average of the growth forecast gives equal weight to all surveyed analysts' projections. It is problematic as to whether any particular analyst's forecast is most representative of general market expectations. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations. The growth rates I used in my DCF analyses are shown on Exhibit CUB-ICNU/406.

Q. WHAT ARE THE RESULTS OF YOUR ANNUAL CONSTANT GROWTH DCF MODEL?

A. As shown on Exhibit CUB-ICNU/407, the DCF return for my comparable group is 9.2%.

Q. DO YOU HAVE ANY COMMENTS CONCERNING THE RESULTS OF YOUR DCF ANALYSIS?

A. Yes. I believe the results of my constant growth DCF analysis, and a DCF analysis in general in today's marketplace, reflect rational investment financial metrics and reflect today's very low cost capital market. Therefore, the DCF results are reasonable.

Q. WHY DO YOU BELIEVE YOUR DCF REFLECTS CONSERVATIVE GROWTH PROJECTIONS?

A. The consensus analysts' growth rate for my comparable group is 4.27% or 4.3%. First, this growth rate is reasonably consistent with five-year projected GDP growth of 5.2%, and considerably higher than the five-year projected GDP inflation growth of 2.4%. Exhibit CUB-ICNU/403, Gorman/32 (Blue Chip Economic Forecast (Mar. 10, 2006)).

Utilities' dividend growth cannot sustain a growth rate that exceeds the growth rate of the overall economy. The growth rate of the utility's service territory is the proxy for the sustainable long-term growth rate of earnings. Utilities invest in plant to meet sales growth, and sales growth in turn is tied to economic activity. Hence, nominal GDP growth is a proxy for the highest sustainable long-term growth rate of the utility.

However, growth of utility companies has historically been tied to the growth rate of inflation. This is because utilities typically pay out a very high percentage of earnings as dividends, thus, limiting the reinvestment of earnings and the growth to their company business platforms. The growth rate used in my DCF analysis is much higher than expected inflation rates, and nears the maximum sustainable growth estimate as proxied by the GDP growth factor. This clearly indicates a very strong and relatively high growth rate used in my DCF estimate.

Moreover, my projected growth rate of 4.27% or 4.3% is considerably higher than the historical growth rate the proxy group has achieved over the last five to ten years, and that projected over the next three to five years. As shown on Exhibit CUB-ICNU/408, the historical dividend growth of my proxy group is substantially lower than the nominal GDP growth.

Q. WHY DO YOU BELIEVE THE DCF YIELD REFLECTS CURRENT LOW COST CAPITAL MARKETS?

A. The DCF yields for my utility group is 4.97%. This yield is higher than the current five-year Treasury note yield of 4.55%, and slightly lower than the projected five-year Treasury note yield of 5.1%. Hence, the DCF yield reasonably reflects both current and projected interest rates.

Q. WHY DO YOU BELIEVE YOUR DCF REFLECTS RATIONAL COMPANY FINANCIAL METRICS AND DIVIDEND EXPECTATIONS?

A. The dividend fundamentals of companies included in my comparable groups show strong and consistent earnings strength in relation to dividends. This indicates that current and projected earnings support dividends and permit the continued predictable growth in dividends.

For example, my comparable group has 2005 dividend payout ratio of approximately 75%, and dividend to book ratios of approximately 7.4%. The dividend payout ratio represents the percentage of earnings paid out as dividends. Traditionally, utility companies have paid out approximately 70% of their earnings as dividends. Value Line's projected dividend to book and payout ratio for my comparable group is 7.3% and 70%, respectively. Hence, a payout ratio of 69% suggests that the companies' earnings will support dividends and retain earnings to produce earnings and dividend growth going forward.

Also, a dividend to book ratio of 7.3% indicates that these dividend payments are affordable in today's low capital cost environment. In essence, companies need to earn 7.3% on their book value in order to produce earnings to pay their dividends. With authorized returns dropping in response to significant declines in capital market costs, these low cost dividends will be supported by today's lower authorized equity returns.

RISK PREMIUM MODEL

Q. PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A. This model is based on the principle that investors require a higher ROR to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends on common equity, or to guarantee returns on common equity investments. Therefore, common equity securities are considered to be more risky than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I estimated the difference between the required return on utility common equity investments and Treasury bonds. The difference between the required return on common equity and the bond yield is the risk premium. I estimated the risk premium on an annual basis for each year over the period 1986 through 2005. The common equity required returns were based on regulatory commission-authorized returns for electric utility companies. Authorized returns are typically based on expert witnesses' estimates of the contemporary investor required return.

The second equity risk premium method is based on the difference between regulatory commission authorized returns on common equity and contemporary "Baa" rated utility bond yields. This time period was selected because over the period 1986 through 2005, public utility bond yields have consistently traded at a premium to book value. This is illustrated on my Exhibit CUB-ICNU/409, where the market to book ratio since 1986 for the electric utility industry was consistently above 1.0. Therefore, over this time period, regulatory authorized returns were sufficient to support market prices that at least exceeded book value. This is an indication that regulatory authorized returns on common equity supported a utility's ability to issue additional common stock, without diluting existing shares. This is an indication that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown on Exhibit CUB-ICNU/410, the average indicated equity risk premium of authorized electric utility common equity returns over U.S. Treasury bond yields has been 5.0%. Of the 20 observations, 14 indicated risk premiums fall in the range of 4.4% to 5.9%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity using this methodology.

As shown on Exhibit CUB-ICNU/411, the average indicated authorized electric utility common equity returns over contemporary Moody's utility bond yields over the period 1986 through 2005 was 3.6%. Removing the three highest and lowest risk premium estimates produces an electric equity risk premium in the range of 3.0% to 4.4%.

Q. HOW DID YOU ESTIMATE PACIFICORP'S COST OF COMMON EQUITY WITH THIS MODEL?

A. I added a projected long-term Treasury bond yield to my estimated equity risk premium over Treasury yields. Blue Chip Financial Forecasts projects the 30-year Treasury bond yields to be 5.3%, and a 10-year Treasury bond to be 5.2%. Exhibit CUB-ICNU/403, Gorman/34 (Blue Chip Financial Forecast (June 1, 2006)). Using the projected 30-year bond yield of 5.3%, and an electric equity risk premium of 4.4% to 5.9%, produces an estimated common equity return in the range of 9.7% to 11.2%, with a mid-point estimate at 10.4%.

I next added my equity risk premium over utility bond yields to a current 13-week average yield on "A" rated utility bonds for the period ending June 2, 2006 of 6.25%. These current "A" utility bond yields are developed on Exhibit CUB-ICNU/412. Adding the utility bond equity premium of 3.0% to 4.4% to an "A" rated bond yield of 6.25% produces a cost of equity in the range of 9.3% to 10.7%, with a mid-point of 10.0%.

My risk premium analyses produce an average return estimate of 10.2% (10.4% to 10.0%).

CAPITAL ASSET PRICING MODEL

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM method of analysis is based upon the theory that the market-required ROR for a security is equal to the risk-free ROR, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$$Ri = Rf + Bi \times (Rm - Rf) \text{ where:}$$

Ri = Required return for stock i
Rf = Risk-free rate
Rm = Expected return for the market portfolio
Bi = Beta - Measure of the risk for stock

The stock specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, firm-specific risks can be eliminated by balancing the portfolio with securities that react in the opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix and production limitations).

The risks that cannot be eliminated when held in a diversified portfolio are nondiversifiable risks. Nondiversifiable risks are related to the market in general and are referred to as systematic risks. Risks that can be eliminated by diversification are regarded as nonsystematic risks. In a broad sense, systematic risks are market risks, and nonsystematic risks are business risks. The CAPM theory suggests that the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risk that investors will be compensated for are systematic or nondiversifiable risks. The beta is a measure of the systematic or nondiversifiable risks.

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A. The CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.

Q. WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A. I used Blue Chip Financial Forecasts' projected 30-year Treasury bond yield of 5.3%. The current 30-year bond yield is 4.6%. Exhibit CUB-ICNU/403, Gorman/34 (Blue Chip Financial Forecast (June 1, 2006)).

Q. WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A. Treasury securities are backed by the full faith and credit of the United States government. Therefore, long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. Therefore, a Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic or market risks. Consequently, for companies with betas less than one, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q. WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A. I relied on the group average Value Line beta estimate for my comparable group of 0.78, as shown on my Exhibit CUB-ICNU/413. A group average beta is more reliable than a single company beta and will, therefore, produce a more reliable CAPM estimate. A group average beta has stronger statistical parameters that better describe the systematic risk of the group, than does an individual company beta. For this reason, a group average beta will produce a more reliable return estimate. Therefore, in my CAPM analysis I will use a beta of 0.78.

Q. HOW DID YOU DERIVE YOUR MARKET PREMIUM ESTIMATE?

A. I derived two market premium estimates, a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

The Ibbotson and Associates' Stocks, Bonds, Bills and Inflation 2006 Year Book publication estimates the historical arithmetic average real market return over the period 1926-2005 as 9.1%. A current five-year consensus analyst inflation projection, as measured by the Consumer Price Index, is 2.4%. Exhibit CUB-ICNU/403, Gorman/34 (Blue Chip Financial Forecast (June 1, 2006)). Using these estimates, the expected market return is 11.7%.[2/] The market premium then is the difference between the 11.7% expected market return, and my 5.3% risk-free rate estimate, or 6.4%.

The historical estimate of the market risk premium was also estimated by Ibbotson and Associates in the Stock, Bonds, Bills and Inflation, 2006 Year Book. Over the period 1926 through 2005, Ibbotson's study estimated that the arithmetic average of the achieved total return on the S&P 500 was 12.3%, and the total return on long-term Treasury bonds was 5.8%. The indicated equity risk premium is 6.5% (12.3% - 5.8% = 6.5%).

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A. As shown on Exhibit CUB-ICNU/414, based on the prospective market risk premium of 6.5%, and historical market risk premium estimate of 6.4%, a risk free rate of 5.3%, and a beta of 0.78, the CAPM estimated return on equity is 10.4%.

2/ (1.024) * (1.097) – 1 = 11.7%.

RETURN ON EQUITY SUMMARY

Q. BASED ON THE RESULTS OF YOUR RATE OF RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR PACIFICORP?

A. Based on my analyses, I estimate PacifiCorp's current market cost of equity to be 9.8%.

TABLE 2

Return on Common Equity Summary

Description	Percent
Constant Growth DCF	9.2%
Risk Premium	10.2%
CAPM	10.4%

My recommended return on equity of 9.8% is at the mid-point of my estimated return on equity range for PacifiCorp of 9.2% to 10.3%. The high end of my estimated range is based on my CAPM and risk premium analyses, and the low end of my estimated range is based on my DCF analysis.

FINANCIAL INTEGRITY

Q. WILL YOUR RECOMMENDED OVERALL RATE OF RETURN SUPPORT PACIFICORP'S CURRENT BOND RATING FROM S&P?

A. Yes. I have reached this conclusion by comparing the key credit rating financial ratios for PacifiCorp at my proposed capital structure and return on equity to S&P's benchmark financial ratios for an "A" rated utility and "BBB" rated utility with a business profile score of 5.

Q. PLEASE DESCRIBE S&P'S USE OF THE FINANCIAL BENCHMARK RATIOS IN ITS CREDIT RATING REVIEW.

A. S&P evaluates a utility's credit rating based on an assessment of its financial and business risks. A combination of financial and business risks equates to the overall assessment of the Company's <u>total</u> credit risk exposure. S&P publishes a matrix of financial ratios that defines the level of financial risk as a function of the level of business risk.

S&P rates a utility's business risk based on a business profile score of 1, lowest risk, up to 10, highest risk. Integrated electric utilities typically have a business profile score from S&P of 4, 5 or 6, while transmission and distribution electric utilities' profile scores primarily range from 2 to 4.

S&P publishes ranges for three primary financial ratios that it uses as guidance in its credit review for utility companies. The three primary financial ratio benchmarks it relies on in its credit rating process include: 1) funds from operations ("FFO") to debt interest expense; 2) FFO to total debt; and 3) total debt to total capital.

Q. HOW DID YOU APPLY S&P'S FINANCIAL RATIOS TO TEST THE REASONABLENESS OF YOUR RATE OF RETURN RECOMMENDATIONS?

A. I calculated each of S&P's financial ratios based on PacifiCorp's cost of service for retail operations and PacifiCorp's off-balance sheet debt for the 2007 test year.

While S&P would be concerned with total PacifiCorp/MEHC consolidated financial ratios in its credit review process, my investigation in this proceeding is to judge the reasonableness of my proposed cost of capital for setting rates in PacifiCorp's utility operations. Hence, I am attempting to determine whether the rate of return and cash flow generation opportunity reflected in my proposed utility rates for PacifiCorp will support

PacifiCorp's current secured "A-" and unsecured "BBB+" investment grade bond ratings and financial integrity.

Q. HOW DID YOU ARRIVE AT PACIFICORP'S TEST YEAR OFF-BALANCE SHEET DEBT EQUIVALENT?

A. In response to ICNU Data Request ("DR") No. 7.63, PacifiCorp provided some information concerning its purchased power financial obligations for the period 2006 through the end of the current contract terms. In his testimony, PacifiCorp witness Mr. Williams stated that S&P has recently estimated PacifiCorp's off-balance sheet debt equivalence to be approximately $520 million, and imputed debt interest expense of $52 million. PPL/300, Williams/9.

Unfortunately, Mr. Williams failed to provide support for that analysis, nor did he identify at what point in time that estimate was made. This is significant as PacifiCorp's off-balance sheet debt equivalence is shrinking over time because the OBS obligation is being amortized. Specifically, as noted by S&P: "When analyzing forecasts, the NPV of the PPA will typically decrease as the maturity of the contract approaches." PPL/302 Williams/4.

Hence, PacifiCorp's purchased power OBS obligation for calendar year 2005, which appears to be the time period reflecting Mr. Williams' study, will be higher than its off-balance sheet debt equivalence for calendar year 2007, which is the test year in this proceeding. Hence, I adjusted Mr. Williams' OBS debt equivalence to the test year. For the 2007 test year, PacifiCorp's OBS PPA debt equivalent is estimated to be $456 million based on the data provided in Confidential Exhibit CUB-ICNU/415.

Q. PLEASE DESCRIBE THE RESULTS OF THIS CREDIT METRIC ANALYSIS FOR PACIFICORP.

A. The S&P financial metric calculations for PacifiCorp are developed on my Exhibit CUB-ICNU/416.

As shown on my Exhibit CUB-ICNU/416, based on an equity return of 9.8%, PacifiCorp will be provided an opportunity to produce a FFO to debt interest expense of 4.1x. This FFO to interest coverage ratio is stronger than S&P's benchmark ratio guideline of 4.5x to 3.8x for an "A" rated utility company and 3.8x to 2.8x for a "BBB" rated utility company with a business profile score of 5.

At my proposed capital structure, PacifiCorp's total debt ratio to total capital is 53%. This is within S&P's "BBB" rated utility range of 50% to 60% for a "BBB+" utility.

Finally, PacifiCorp's retail operations FFO to total debt coverage at a 9.8% equity return would be 21%, which is again within S&P's financial metric range of 15% to 21% for a "BBB+" rated utility company with a business profile score of 5.

At my proposed capital structure and return on equity, PacifiCorp's financial metrics are supportive of a strong "BBB" and a weak "A" utility bond rating at PacifiCorp's current business profile score of 5.

Since the PPA debt obligations have a meaningful impact on these ratios, it is necessary to consider the impact on PacifiCorp's ratios and its ability to support both its secured and unsecured bond rating. When unsecured PPA debt equivalents are included, PacifiCorp's credit ratios are consistent with a strong "BBB" utility. The credit metrics, thus, supports PacifiCorp's unsecured bond rating of "BBB+" when PPA debt is included. However, if the PPA debt equivalents are removed, along with other subordinated debts, PacifiCorp's cash flow coverage metrics would provide much stronger coverage of PacifiCorp's senior secured debt obligations. Hence, on a senior secured basis, PacifiCorp's current "A-" bond rating would be supported at my proposed return on equity and capital structure. As a result, my credit metric analysis demonstrates that my recommendations will support PacifiCorp's current secured "A-" bond rating, and unsecured "BBB+" bond rating.

RESPONSE TO PACIFICORP WITNESS SAMUEL HADAWAY

Q. WHAT RETURN ON COMMON EQUITY IS PACIFICORP PROPOSING FOR THIS PROCEEDING?

A. PacifiCorp is proposing to set rates based on a return on equity of 11.5%, which includes a 50 basis point Oregon risk adder. PacifiCorp's proposed return on equity is supported by its witness Dr. Samuel Hadaway's return on equity analysis. Dr. Hadaway recommends a return on equity for PacifiCorp of 11.0% based on the approximate midpoint of two of his three DCF model results of 10.7% to 11.3% (PPL/200, Hadaway/5), and a 50 basis point adder to reflect his belief that PacifiCorp is more risky than his proxy group.

Q. IS DR. HADAWAY'S PROPOSED 50 BASIS POINT RISK ADDER REASONABLE?

A. No. Contrary to Dr. Hadaway's erroneous conclusions, PacifiCorp is not more risky than his proxy group, and an equity return adder should not be included with the proxy group equity return estimate. First, the proxy group is comparable in risk to PacifiCorp for several reasons. Dr. Hadaway's proposed proxy group, if anything, contains companies with higher risk than that of PacifiCorp, and thus, a reduction to the return on equity might be appropriate. Specifically, in reviewing Dr. Hadaway's proxy group, I found it appropriate to remove companies that did not have wide following by the market, and were involved in meaningful acquisition and asset sales activities. After removal of these companies, I found that the credit rating, business profile score and capital structure mix of the proxy group is reasonably risk comparable to PacifiCorp. Hence, an external return on equity increase to the proxy group is not justified.

Second, the types of risk identified by Dr. Hadaway in support of his 50 basis point equity return adder are considered in a total investment risk of PacifiCorp and his proxy group, and an external adjustment is not necessary or reasonable. Finally, the independent credit rating agencies' assessment of the risk identified by Dr. Hadaway are not noted as significant risks and, therefore, do not justify the equity return risk adder proposed by Dr. Hadaway.

Q. WHAT ARE THE RISKS IDENTIFIED BY DR. HADAWAY IN SUPPORT OF HIS RETURN ON EQUITY ADDER?

A. Dr. Hadaway contends that PacifiCorp does not have a fuel adjustment mechanism that places more commodity risk on PacifiCorp, and he states that the Company's ability to earn its authorized return on equity has been weaker than that of his proxy group, and he states that Oregon Senate Bill ("SB") 408's restriction on income tax recovery places PacifiCorp at greater risk.

Q. DO THESE SPECIFIC RISK FACTORS IDENTIFIED BY DR. HADAWAY SUGGEST THAT PACIFICORP HAS SIGNIFICANTLY MORE OPERATING RISK THAN THAT OF HIS PROXY GROUP?

A. No. With respect to fuel adjustment mechanisms, S&P specifically states that PacifiCorp has risk management policies in place that mitigate this commodity risk exposure. S&P states as follows:

> As with other electric utilities, PacifiCorp is exposed to natural gas and power price and volume volatility. In fiscal 2004, for example, 54% of the operating expenses of $2.1 billion (excluding depreciation and amortization) were for power and fuel costs. The company strives to maintain a balanced or slightly long position to protect against unexpected events resulting from weather, forced outages, transmission constraints, and low hydro years. Through financial and physical contracting, the utility's exposure to commodity price fluctuations is relatively modest. Its five-day, 99% value at risk (VaR) for natural gas and electric purchases and sales is expected to be $16 million through 2006. Its VaR for the fiscal year ended March 31, 2004, was $18 million, but has been as high as $23 million over the year and as low as $8 million.
>
> The Company engages in only limited pure trading and marketing activities, with most sales related to the buying and selling of power to optimize its assets. PacifiCorp's risk management policies do not allow speculative trading or position taking, but do allow for some arbitrage trading, for example back-to-back buy/sell trades. In addition, most of PacifiCorp's wholesale sales are system firm, allowing the utility to cut deliveries without penalty if there is a force majeure event on its system. The Company also maintains a general policy of being balanced or long during periods of high demand.
>
> PacifiCorp's current policies are to fully hedge its gas purchases to achieve a balanced or slightly long position two years out. As a result, the gas supply required to meet the utility's average expected daily burn rate of 102,000 MMBTUs is fully hedged through 2006 via the use of fixed price, forward, physical purchases. With the addition of Currant Creek and Lakeside, which together will add 1,059 MW of new gas generation by 2007, gas purchase requirements are expected to be at least 195,000 MMBTUs per day. The Company is re-evaluating its hedging strategies to incorporate physical and financial hedging mechanisms. To manage hydro risk, the utility has entered into a five-year stream flow budget hedge with Aquila Merchant Services that makes a payment to the utility in dry years and requires a payment from the utility in wet years. The agreement expires September 2006.

Exhibit CUB-ICNU/403, Gorman/29 (S&P RatingsDirect, Research: PacifiCorp (Sept. 22, 2004)) (emphasis added).

In terms of PacifiCorp's ability to earn its authorized return on equity, S&P also stated that PacifiCorp has been successful in implementing regulatory mechanisms that reduced risk, and will increase its probability of earning its authorized return on equity. Exhibit CUB-ICNU/403, Gorman/24 (S&P Credit FAQ: MidAmerican's Acquisition of PacifiCorp – Implications for PacifiCorp's Bondholders (Mar. 21, 2006)).

Moody's responds to this risk by stating as follows:

> **Recent key regulatory decisions have been constructive**
> For the past several years, PacifiCorp has been actively seeking regulatory support across the company's six-state jurisdiction in an effort to enhance returns at the utility. To date, PacifiCorp's efforts have been reasonably successful.

Exhibit CUB-ICNU/403, Gorman/16 (Moody's Investor Service, Global Credit Research, Analysis, PacifiCorp (June 2005)).

In terms of recovery of income tax expense, it is simply not just and reasonable to expect that customers pay expenses, which the Company will not actually incur and pay to a vendor. Specifically, if PacifiCorp does not pay income tax to government taxing units, then there is no legitimate reason to allow it to recover those expenses in rates. Indeed, ratepayers paying the utility's income tax expense that is ultimately paid to taxing authorities provides benefits to retail customers in terms of providing the funding for government services and infrastructure investments. This ratepayer benefit created by paying the utility's income tax expense is not realized if the utility retains the income tax expense at the parent company level in order to enhance a leveraged investment return by the parent company. As such, there is no just and reasonable basis to expect ratepayers to compensate utilities for expenses that are not actually incurred and paid to vendors.

Q. DO DR. HADAWAY'S METHODOLOGIES SUPPORT HIS 11.0% RETURN ON EQUITY, EXCLUDING HIS PACIFICORP RISK ADDER RECOMMENDATION?

A. No. As discussed below, an appropriate reflection of current market data in Dr. Hadaway's own analyses would produce model results that support a return on equity in the range of 9.1% to 9.9% with a midpoint of 9.5%. This is discussed in more detail below.

Q. FIRST, DO YOU HAVE ANY GENERAL COMMENTS CONCERNING DR. HADAWAY'S PROPOSED RETURN ON EQUITY FOR PACIFICORP IN THIS PROCEEDING?

A. Yes. Dr. Hadaway is rejecting viable and legitimate cost of equity estimates simply because he believes them to be too low. Specifically, Dr. Hadaway places no reliance on his own constant growth DCF model results because he claims the numbers are too low. He suggests that these estimates are too low based on the results of his risk premium analyses. However, there is no support for this contention. An appropriate return on equity should be based on reasoned judgment and complete analyses, including DCF and risk premium studies.

It is inappropriate for Dr. Hadaway to simply reject the results of his constant growth DCF model as too low, particularly since that model was overstated by the use of excessive projections of GDP growth. Further, his risk premium model is flawed because he ignores current market yields. Therefore, his benchmark for judging what is too low is itself inflated and biased. Further, reflecting current consensus growth rates in his multi-stage DCF model would produce results similar to his constant growth DCF model. In all cases, Dr. Hadaway's own DCF analyses with reasonable growth rates suggest a return on equity of 9.8% is fair and reasonable for PacifiCorp in this proceeding.

Q. PLEASE DESCRIBE DR. HADAWAY'S METHODOLOGY SUPPORTING HIS RETURN ON COMMON EQUITY.

A. Dr. Hadaway develops his return on common equity by conducting three versions of the Discounted Cash Flow analysis, a utility risk premium analysis, and he evaluated risk premium analyses conducted by Ibbotson & Associates and a study published by Harris & Marston ("H&M"). The results of his ROE analysis are shown at page 43 of his testimony. PPL/200, Hadaway/43. I have summarized Dr. Hadaway's results below in Table 3 under Column 1. Under Column 2, I show the results of Dr. Hadaway's analyses adjusted for updated data and more reasonable application of the models.

As shown below in Table 3, using updated information, more reasonable estimates of gross domestic product growth, and a better proxy of estimates of a risk adjusted equity risk premium appropriate for PacifiCorp, Dr. Hadaway's analyses would support a return on equity for PacifiCorp of less than 10.0%. Each of Dr. Hadaway's cost of equity models will be discussed below.

TABLE 3

Summary of Hadaway's ROE Estimates

Description	Hadaway Results (1)	Adjusted Hadaway Results (2)
Constant Growth DCF – (Traditional)	Reject	9.1%
Constant Growth – (GDP Growth)	11.2% - 11.3%	9.9%
Multi-Stage Growth DCF	10.7% - 11.3%	9.6%
Estimated DCF Range	10.7% - 11.3%	9.1% - 9.9%
Risk Premium Utility	10.74%	9.3%
Ibbotson Risk Premium	10.80%	9.9%
Harris & Marston Risk Premium	11.43%	10.6%

Source: PPL/200, Hadaway/43.

Q. PLEASE DESCRIBE DR. HADAWAY'S CONSTANT GROWTH DCF ANALYSIS.

A. Dr. Hadaway's constant growth DCF analysis is shown on PPL/205, Hadaway/1-5. As shown on that exhibit, Dr. Hadaway's constant growth DCF analysis is based on a recent price and an average of three growth rates: 1) Zack's; 2) Value Line; and 3) Dr. Hadaway's estimate of GDP growth.

Q. IN WHAT WAY DID DR. HADAWAY OVERSTATE HIS CONSTANT GROWTH DCF ANALYSIS?

A. Dr. Hadaway used a GDP growth rate of 6.6% as one of three growth rates. His GDP growth rate is developed based on the achieved GDP growth over the last 10, 20, 30 and 40-year periods, as shown on his PPL/204. Dr. Hadaway states at page 39 of his testimony that he reviewed the historical GDP growth for various time periods from 1947 through 2004. He claims he gave more weight to more recent years in his GDP forecast.

Q. IS DR. HADAWAY'S PROJECTED 6.6% GDP REASONABLE?

A. No. His growth rate is unreasonable for principally two reasons. First, it significantly exceeds the consensus of security analysts' projected nominal GDP growth over the next five and 10 years of 5.2% as published by the Blue Chip Economic Forecast on March 10, 2006. Second, a breakdown of Exhibit PPL/204 shows that his 6.6% nominal GDP growth rate includes an inflation assumption that is dramatically higher than the market's current assessment of future inflation.

This analysis is shown in Table 4 below. As shown on Line 1 of Table 4, I relied on Exhibit PPL/204 to decompose Dr. Hadaway's nominal GDP growth projection of 6.6% and to a real GDP factor of 3.3%, and the GDP inflation of 3.2%. Relying on the same breakout based on the consensus forecast of the common as published by Blue Chip Financial Forecast, economists are projecting real GDP growth of 3.1% and 3.0% over the next five and 10 year periods, respectively, and in both cases are projecting GDP inflation of 2.1%. Dr. Hadaway's GDP growth factors significantly exceed consensus economists' projections, and current market expectations, because he has dramatically overstated the market assessment of future inflation.

Importantly, using independent, verifiable market economists' projections of forward GDP growth shows that Dr. Hadaway's forecast is out of line with current market expectations. Specifically, consensus economists' projections of future GDP growth over the next five and ten years is 5.2%. Exhibit CUB-ICNU/403, Gorman/32 (Blue Chip Economic Forecast (Mar. 10, 2006)).

As is evident in the table below, Dr. Hadaway's historical GDP reflects historical inflation, which is much higher than, and not representative of, the consensus economists' inflation projections over the next five and ten years.

TABLE 4

GDP Projections

	GDP Inflation	Real GDP	Nominal GDP
Hadaway	3.2%	3.3%	6.6%
Current 5-Year Projection	2.1%	3.1%	5.2%
Current 10-Year Projection	2.1%	3.0%	5.2%

Exhibit CUB-ICNU/403, Gorman/32 (Blue Chip Economic Forecast (Mar. 10, 2006)).

Dr. Hadaway's 6.6% nominal GDP growth is flawed and unreasonable because it is much higher than current market GDP forward expectations and inflates his DCF estimates.

Q. HOW WOULD DR. HADAWAY'S DCF ANALYSES CHANGE IF A MARKET-BASED GDP GROWTH RATE IS INCLUDED IN HIS ANALYSIS?

A. As shown on Exhibit CUB-ICNU/417, I updated Dr. Hadaway's DCF analyses using the consensus economists' five-year projected GDP growth rate of 5.2%. Using this consensus projected GDP growth rate reduces his DCF result from 9.5% to 9.1%, his long-term GDP growth rate from 11.3% to 9.9%, and his two-stage growth DCF model from 10.8% to 9.6%. The average of Dr. Hadaway's adjusted DCF models is 9.5%.

Q. PLEASE DESCRIBE DR. HADAWAY'S UTILITY RISK PREMIUM ANALYSIS.

A. Dr. Hadaway's utility bond yield versus authorized return on common equity risk premium is shown on PPL/206, Hadaway/1. As shown on this exhibit, Dr. Hadaway compares the contemporary Moody's average bond yield for utility companies and the authorized regulatory commission return on common equity over the period 1980 through 2005. Based on this analysis, Dr. Hadaway estimates an average indicated equity risk premium over contemporary utility bond yields of 3.08%.

Dr. Hadaway then adjusts the average equity risk premiums using a regression analysis based on an expectation that there is an ongoing inverse relationship between interest rates and equity risk premiums. Based on this regression analysis, Dr. Hadaway increases his equity risk premium from 3.08% up to 4.44%. He then adds this inflated equity risk premium to a projected "A" bond yield of 6.3%.

Dr. Hadaway estimates a projected utility bond yield based on a 100 basis point spread of projected long-term Treasury bond yield of 5.3% for the first quarter of 2007.

He then produces his risk premium return of 10.74% by adding his projected utility bond yield of 6.3%, to his adjusted equity risk premium of 4.44%, to produce a risk premium in turn of 10.74%.

Q. IS DR. HADAWAY'S UTILITY BOND RISK PREMIUM ANALYSIS REASONABLE?

A. No. Dr. Hadaway has unreasonably attempted to create a forward-looking specific point risk premium estimate using this historical data. This is not reasonable because the data and model are not this precise. For example, interest rate volatility and inflation uncertainty in the 1980s and early 1990s is not reasonably representative of interest rate volatility and inflation outlooks currently and going forward. Inflation volatility or uncertainty over this historical time period had an impact on utility bond yields, valuations and equity risk premiums. This inflation volatility, however, is not characteristic of the current economy or capital markets. The only reasonable interpretation of Dr. Hadaway's analysis is developing a general range of equity risk premiums.

Further, Dr. Hadaway's aggression analysis essentially smoothes the reduction for authorized returns on equity based on changes to market interest rates. While authorized returns on equity have not dropped as fast as changes to debt interest rates, this is likely the result of conservative commission practices in setting authorized returns on equity, but not the result of fundamental financial principles, which would indicate that equity returns spread should increase as nominal interest rates drop. Rather, state utility commissions have been concerned about the sustained ability of the drop in interest rates, and thus have authorized returns on equity reductions that have not kept track with reductions to interest rates. This is relevant now because interest rates have started to increase, and, therefore, an increase in the interest rate should not correspond to an increase in authorized returns on equity.

Q. IS DR. HADAWAY'S PROPOSED ADJUSTMENT TO HIS EQUITY RISK PREMIUM TO REFLECT THE INVERSE RELATIONSHIP BETWEEN INTEREST RATES AND EQUITY RISK PREMIUMS REASONABLE?

A. No. The academic literature on the inverse relationship between interest rates and equity risk premiums has observed that there has been an inverse relationship that was caused by changes to perceived risk differentials between debt and equity investments. However, it is not tied only to changes in nominal interest rates. Further, the relationship between interest rates and equity risk premiums is not constant, but rather can change materially over time.

The academic literature addressing this issue that I am familiar with is based on market data in the 1980s and very early 1990s. During the 1980s and very early 1990s, an inverse relationship did exist, but that was not the case prior to 1980. For example, a paper written by Eugene Brigham, Dilip K. Shome and Steve R. Vinson stated as follows in the abstract:

> (4) Before 1980, equity risk premiums for utilities increased as interest rates rose, but after that date an increase in interest rates was associated with lower risk premiums. As a result, in recent years a 100 basis point increase in long-term interest rates has led to an increase of about 37 basis points in the cost of equity. (5) Risk premiums are not stable; they change substantially over relatively short periods of time, and this volatility has implications for anyone who seeks to measure equity capital costs on the basis of a debt yield plus a risk premium, including advocates of the CAPM approach.

"The Risk Premium Approach to Measuring a Utility's Cost of Equity," Public Utility Research Center (Aug. 1984) (emphasis added). In a more recent, yet still outdated, study by Robert S. Harris and Felicia C. Marston published in the Journal of Applied Finance – 2001, "The Market Risk Premium: Expectational Estimates Using Analysts Forecasts," the authors expanded an earlier study of risk premiums to cover a period of 1982-1998. In this study, the authors noted a historical inverse relationship between equity risk premiums and interest rates. However, the authors went into detail to explain why that historical relationship was likely affected more by relative investment risk changes, and not simply changes to nominal interest rates as Dr. Hadaway implies in his testimony. The authors state as follows:

> The market risk premium changes over time and appears inversely related to government interest rates but is positively related to the bond yield spread, which proxies for the incremental risk of investing in equities as opposed to government bonds.

Importantly, the authors in that same study concluded as follows:

> As a result, our evidence does not resolve the equity premium puzzle; rather, the results suggest investors still expect to receive large spreads to invest in equity versus debt instruments.
>
> There is strong evidence, however, that the market risk premium changes over time. Moreover, these changes appear linked to the level of interest rates as well as *ex ante* proxies for risk drawn from interest rate spreads in the bond market.

Clearly, the academic literature does not support a simplistic inverse relationship between interest rates and equity risk premiums. Rather, the authors of these studies recognize that equity risk premiums change with perceived changes in investment risk. Dr. Hadaway's simplistic analysis has no bearing on changes to perceived risk, and inappropriately increases equity risk premiums for no other reason than a reduction in nominal interest rates.

Reductions to nominal interest rates over the last ten years are simply not adequate reason for increases to equity risk premiums. Indeed, decreases to interest rates over the last ten years likely have been caused by reduced inflation expectations, which would decrease both bond interest rates and common equity required returns. Reduced inflation expectations alone should not change relative debt to equity investment risk, and thus would not cause equity risk premiums to increase. Consequently, Dr. Hadaway's proposal to reflect an inverse relationship between equity risk premiums and bond interest rates is flawed and unreliable, and should be rejected.

Q. THE HARRIS ET AL. ARTICLE CITED ABOVE INDICATES THAT A BOND YIELD SPREAD COULD BE USED TO INDICATE WHETHER INDUSTRY RISK AND EQUITY RISK PREMIUMS HAVE CHANGED. DO UTILITY BOND SPREADS OVER TREASURY BONDS INDICATE THAT THE UTILITY INDUSTRY RISK HAS INCREASED AND UTILITY EQUITY RISK PREMIUMS HAVE INCREASED?

A. No. Indeed, utility bond yield spreads over Treasury yields currently are below average, relative to the last 25 years. This indicates that the market's assessment of investment risk for the utility industry is not higher now than it has been over the last 25 years. Hence, utility equity risk premiums today should conservatively be comparable to the average equity risk premiums experienced over the last 25 years, not higher, as Dr. Hadaway asserts.

This bond spread between utility bonds and Treasury bonds is shown on my Exhibit CUB-ICNU/418. As shown on this exhibit, the 2005 spread between "A" rated and "BBB" rated utility bonds is 1.10% and 1.44%, respectively. For the first six months of 2006, the utility bond yield spread increased to 1.08% and the "Baa" utility bond spread over Treasuries has decreased to 1.34%, relative to 2005. As clearly illustrated on this exhibit, utility bond yield spreads over Treasury yields are amongst the lowest they have been in recent history. This clearly indicates that utilities' assessment of utility risk is decreasing, not increasing as implied by Dr. Hadaway. Since the risk of utility securities is not increasing, there is no justification for increasing the equity risk premium as Dr. Hadaway has done.

Again, this indicates that the utility industry's risk has not increased, but rather is stable to declining. This is consistent with the "back to basics" outlook of the utility industry, where many utilities are shedding higher-risk non-regulated companies and returning back to core competencies of operating low-risk regulated utility operations.

Q. DOES DR. HADAWAY'S RISK PREMIUM ANALYSIS SUPPORT A RETURN ON EQUITY OF 10.74% IN THIS PROCEEDING?

A. No. His electric equity risk premium estimate of 4.44% is overstated and he applies this inflated premium to an inflated utility bond yield. If Dr. Hadaway's risk premium of 3.08% is added to the current yield on single "A" rated utility bonds of 6.25%, the risk premium return would indicate a fair return for PacifiCorp of 9.33%.

Q. DID DR. HADAWAY PERFORM ANY TESTS OF HIS RISK PREMIUM ANALYSIS RESULTS?

A. Yes. Dr. Hadaway compared his utility risk premium analysis to studies performed by Ibbotson & Associates and H&M. Dr. Hadaway states that Ibbotson & Associates studied the return on common stocks versus corporate bonds for the period 1926 through 2004. The Ibbotson study found that the arithmetic mean risk premium was 6.2%, and the geometric mean return was 4.5%. He states that using the geometric and arithmetic mean return and a debt cost of 6.3%, would produce an indicated equity return in the range of 10.8% and 12.5%, respectively. PPL/200, Hadaway/42.

Dr. Hadaway discusses the H&M study stating that it looked at the equity premium over U.S. Government bonds of 6.47%, and the equity risk premium of common stocks over corporate bonds to be 5.13%. Dr. Hadaway finds that the H&M study would support an equity risk premium over an "A" rated corporate debt of 11.4% (6.3% debt cost and 5.1% risk premium). Id.

Q. DO THE INDICATED RISK PREMIUM RESULTS FROM THE IBBOTSON & ASSOCIATES AND H&M STUDIES SUPPORT A RETURN ON COMMON EQUITY FOR PACIFICORP OF 10.8% AND 11.4% AS ESTIMATED BY DR. HADAWAY?

A. No. The Ibbotson & Associates and H&M studies are based on common equity returns and equity risk premiums for the overall market. Both of these studies are based on the returns for the S&P 500. Dr. Hadaway did not, and cannot, show that the S&P 500 is risk comparable to PacifiCorp's as a regulated electric utility.

In fact, it is widely recognized that electric utility risk is considerably lower than that of the overall market. This is evident by a review of the beta coefficients measured by Value Line for utility companies. As I noted above with respect to my CAPM analysis, electric utility company stock market risk is approximately 80% of that of the overall market. Hence, while the equity risk premiums derived from these two studies may be appropriate for the overall market, they overstate significantly a reasonable equity risk premium for a low risk regulated electric utility such as PacifiCorp. Therefore, Dr. Hadaway's use of the Ibbotson and H&M studies' equity risk premiums to produce a return on common equity for PacifiCorp is unreasonable and should be rejected.

Q. CAN THE RISK PREMIUM STUDIES PUBLISHED BY IBBOTSON AND H&M BE USED TO DEVELOP A COMMON EQUITY ESTIMATE FOR PACIFICORP?

A. Only generally. By recognizing PacifiCorp's much lower risk than that of the overall market, the equity risk premiums developed by Ibbotson and H&M, of 4.5% to 6.2%, and 5.13%, should be adjusted by a factor of approximately 80%. This 80% represents the current estimate of a utility beta as published by the Value Line Investment Survey. Using an 80% adjustment factor to reflect PacifiCorp's higher than market risk, these studies' equity risk premiums adjusted for the lower risk would be reduced to 3.6% (4.5% * 80%) to 5.0% (6.2% * 80%) for a range of 9.85% to 11.25%. In the case of H&M, a risk premium of 4.1% (5.13% * 80%) is reasonable, producing a return of 10.55%. In both cases, I am relying on an "A" utility bond yield of 6.25%. Going to the low end of this risk premium range is reasonable now, because as discussed above, utility bond risk premiums relative to Treasury bonds are at historically low levels, thus indicating the markets positive perception to the utility industry's back to basics, and expectations of lower operating risk relative to non-regulated investments. Hence, these analyses suggest that a 9.9% return on equity is a fair and just risk-adjusted return on equity for PacifiCorp's regulated utility operations.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/401

MICHAEL P. GORMAN QUALIFICATIONS

July 12, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. PLEASE STATE YOUR OCCUPATION.

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

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

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

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

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

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

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

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

Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

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

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

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/402

RATE OF RETURN AT 9.8% ROE

July 12, 2006

PacifiCorp. - Oregon

Rate of Return at 9.8% ROE

Line	Description	Weight (1)	Cost (2)	Weighted Cost (3)
1	Long-Term Debt	50.0%	6.37%	3.19%
2	Preferred Stock	1.1%	6.54%	0.07%
3	Common Equity	48.9%	**9.80%**	4.79%
4	**Total**	**100.00%**		**8.05%**

Source:
Williams Direct, Exhibit PPL 300 at 3.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/403

EXCERPTS OF CREDIT RATING AGENCY REPORTS

AND BLUE CHIP FORECASTS

July 12, 2006

CUB-ICNU/403
Gorman/1

October 14, 2002
Vol. 11, No. 41

Standard & Poor's UTILITIES & PERSPECTIVES

GLOBAL UTILITIES RATING SERVICE

STANDARD & POOR'S

Downward Credit Pressure Continues on U.S. Power Industry

Rating activity was overwhelmingly negative for U.S. utilities (electric, gas, pipeline, and water) in this year's turbulent third quarter, with several companies experiencing numerous downgrades. Since July 1, 2002, there have been 57 downgrades among holding companies and operating subsidiaries, compared with just eight upgrades (three of which relate to Northern Natural Gas Co.). For the same period in 2001, there were only nine downgrades and five upgrades. The torrid pace of the previous six months (78 downgrades and six upgrades) continued in the third quarter, as did the steep credit decline that began in 2001, when Standard & Poor's recorded 81 downgrades and 29 upgrades. In addition, the third quarter witnessed many new CreditWatch listings and outlook revisions, most of which were negative.

Although U.S. power industry creditworthiness began to weaken before 2001, the California energy crisis and the Enron bankruptcy hastened the negative trend. The erosion can be traced mainly to:

- Weakening financial profiles;
- Loss of investor confidence that has affected liquidity and financing flexibility;
- Heightened business risk derived from more investment outside the traditional regulated utility business, particularly unregulated generation and energy trading and marketing;
- Capital and corporate restructuring efforts;
- Regulatory difficulties; and
- Mergers and acquisitions.

These trends, in turn, reflect companies' strategies to deal with an increasingly uncertain and competitive market, while also seeking to enhance shareholder value.

In just 12 months, the number of companies rated 'A' and above has significantly declined, while the number of firms rated 'BBB' and below has risen substantially. In this regard, about 49% of the industry now falls in the 'BBB' category rating, while a full 11% are rated below investment grade, including five companies that are rated 'D', compared with 40% and 5%, respectively, at the end of September 2001. The decline in the 'A' and 'AA' rating category has been precipitous, with just 40% of the industry carrying ratings of 'A' and above, versus 55% one year earlier. Notably, although the average rating for the power sector as a whole has slipped to 'BBB+', companies that continue to emphasize a vertically integrated structure are hanging onto an 'A-' average. But utility holding companies that have ventured too far afield from their core competencies have suffered weakening market capitalization and, in many instances, rating downgrades.

Despite the large number of rating downgrades and ongoing negative pressures on utility credit quality, the sector remains solidly investment grade. This is in line with the large percentage of companies (86%) that have average or above-average business profiles.

Capital Market Update

Financing activity declined in the past 12 months following a significant increase in 2001. The amount of long-term debt, hybrid preferred securities, and preferred stock issued during the first nine months of 2002 was about $56.9 billion, compared with approximately $61.2 billion issued in the same period in 2001. The decrease is attributable to a number of factors, among them capital market jitters, especially for those issuers that require access to the capital markets, a consequent heavier reliance on bank debt, sliding wholesale electricity prices, and reduced capital expenditures across all sectors, but most significantly as the result of the postponement or cancellation of planned new power plants.

Subpar Financial Measurements

A heavy debt burden has driven down key measures of bondholder protection in recent years. Total debt as a percentage of total capitalization was an aggressive 59.8% at June 30, 2002 (the latest period in which comparable data is available) compared with 54.9% almost four years earlier at year-end 1998. This debt level, while just one measure of financial health, is characteristic of a 'BB' rating category credit with an average business position. Much of the increase in leverage can be traced to debt raised at the parent or intermediate holding company level to fund unregulated activities. The material increase in leverage has not been offset by strengthening cash flows, and funds from operations to total debt has accordingly steadily declined, falling below 16% in June 2002 from 21% in 1998. This key financial ratio is also typical of a 'BB' category company. Funds flow coverage of interest and pretax interest coverage have also slipped, to 3.3 times (x) and 2.8x, respectively, for the rolling 12 months June 2002, from 3.9x and 3.1x in 1998. These levels are just suitable for companies in the 'BBB' rating group. However, the aforementioned ratios actually rose, although very slightly, in 2001 and June 2002 because of lower interest rates. Of course, there are several other financial and qualitative factors that determine credit quality, but given eroding financial parameters and riskier business profiles the median rating for the utility industry may eventually slip out of the high 'BBB' category.

Back to Table of Contents
Next Page

Looking Ahead

At the end of September 2002, just 48% of all utility rating outlooks were stable, compared with nearly 60% just one year ago. The decline is attributable mainly to the substantial increase in ratings that carry negative outlooks or are listed on CreditWatch. The percentage of outlooks that are negative has reached a high 31%, continuing to strongly overshadow positive outlooks, which stand at just 3%. This results mostly from a proliferation of higher-risk business strategies, constrained access to capital markets due to investor skepticism over accounting practices and disclosure, investigations on various regulatory levels, weak competitive positioning, and an anemic wholesale power market. The remaining 18% of companies are on CreditWatch—84% carry a negative listing, 9% positive, and 7% developing (which indicates that a rating may be raised, lowered, or remain unchanged). These percentages suggest that frequent rating changes will continue.

The Downgraded…

The ratings on Duke Energy Corp., Duke Capital Corp., Westcoast Energy Inc., Union Gas Ltd., and other related subsidiaries were lowered and removed from CreditWatch. The corporate credit rating for Duke Energy Trading and Marketing (DETM), which is 40% owned by Exxon Mobil Corp., was also lowered. Duke Energy Field Services LLC's rating was affirmed. The outlooks are stable.

Lower ratings reflect a reassessment of Duke Energy's consolidated creditworthiness given the increasing risk of energy trading and merchant generation activities. The CreditWatch negative listing is removed because Standard & Poor's does not expect the outcome of the ongoing FERC and SEC investigations into "round-trip" trades to be onerous. Duke Energy has said that less than 1% of its trading revenues came from round-trip trades.

The downgrades also incorporate the financial implications of the current decline in wholesale electricity prices. This deterioration is mitigated by cash flow stability provided by Duke's regulated electric and gas pipeline businesses. Importantly, Duke continues to reduce capital expenditures commensurate with expected reduced cash flow from Duke Energy North America and DETM.

The ratings on Reliant Resources Inc. (RRI) and related entities remain on CreditWatch with negative implications following two downgrades this quarter, pending the refinancing of holding company debt and credit facilities ($5.9 billion, including a $1.4 billion synthetic lease) and debt at RRI subsidiary Orion Power Holdings and its respective subsidiaries ($1.3 billion net of cash). Ratings on RRI subsidiary Reliant Energy Power Generation Benelux B.V. are affirmed

Chart 1

Third Quarter Rating Actions

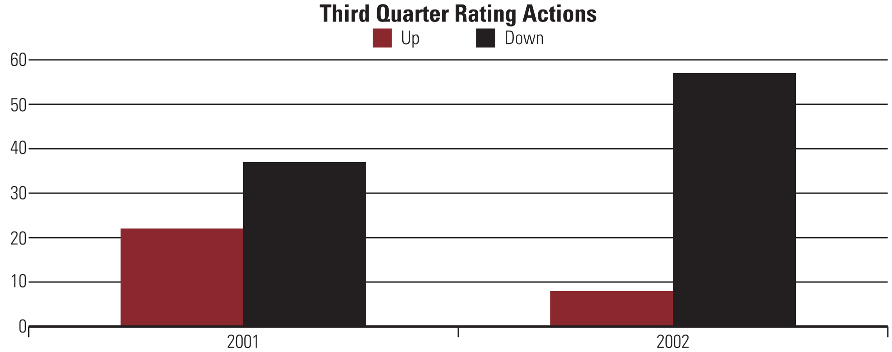
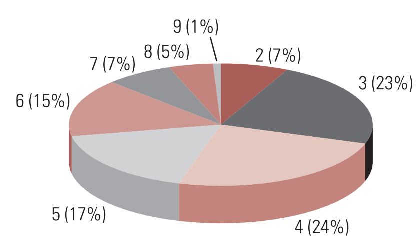


Chart 2

Business Profiles



Business profiles are categorized from "1" (strong) to "10" (weak).

Back to
Table of Contents
Next Page

and remain on CreditWatch as RRI may implement a structure that would insulate this subsidiary.

The rating downgrades reflect increased collateral calls, expectations of a material weakening in credit protection mainly due to the likely increased cost of renewing the bank facilities and expected restrictions on upstreaming cash from Orion Power to RRI, which will limit RRI's ability to service holding company debt. RRI's financial profile is also weakened by the decline in wholesale operations, which is expected to be partially mitigated through 2005 by better-than-expected earnings from the company's Texas retail operations.

CenterPoint Energy Inc.'s (formerly Reliant Energy Inc.) board of directors voted to spin off RRI common stock to CenterPoint shareholders at its Sept. 5, 2002 meeting. Legal separation of the two entities occurred Sept. 30. This should facilitate the current refinancing efforts at both companies.

Ratings on The Williams Cos. Inc. and its subsidiaries were lowered twice in July, resulting in an aggregate five-notch downgrade to 'B+' from 'BBB'. The steep credit decline can be traced to the company's deteriorating liquidity position, as well as rating triggers associated with the AES Ironwood, AES Red Oak, and Georgia EMC tolling agreements, which may require Williams to provide LOCs to each entity. The ramifications of these requirements create significant uncertainty in Williams' financial position and warrant a rating in the 'B' category. These liabilities also add risk to Williams' ability to close on a potential $1.6 billion secured line of credit in the near term or to execute other options to meet liquidity needs. The ratings remain on CreditWatch with negative implications.

The CreditWatch direction on subsidiary Williams Gas Pipelines Central Inc. (Central) was changed to developing from negative on Sept. 17, reflecting the parent's definitive agreement to sell Central to Southern Star Central Corp., a subsidiary of AIG Highstar Capital L.P., for $380 million in cash and the assumption of $175 million in debt. The CreditWatch developing listing reflects the uncertainty surrounding the disposition of the $175 million of senior notes at Central. Assuming that the transaction closes, the rating could be raised, lowered, or withdrawn, depending on how the new owner structures the acquisition.

Dynegy Inc. and subsidiaries Dynegy Holdings Inc., Illinova Corp., and Illinois Power Co. had ratings lowered twice, resulting in a four-notch downgrade to 'B+'. The first downgrade to 'BB' from 'BBB-' was attributable to continuing erosion in Dynegy's core merchant energy business, difficulties in accessing the capital markets and a strained liquidity position. Despite cost savings and cutbacks in capital expenditures, including a reduction in the common dividend payout, needed incremental cash flow had been slow to

Chart 3
Third Quarter Rating Distributions

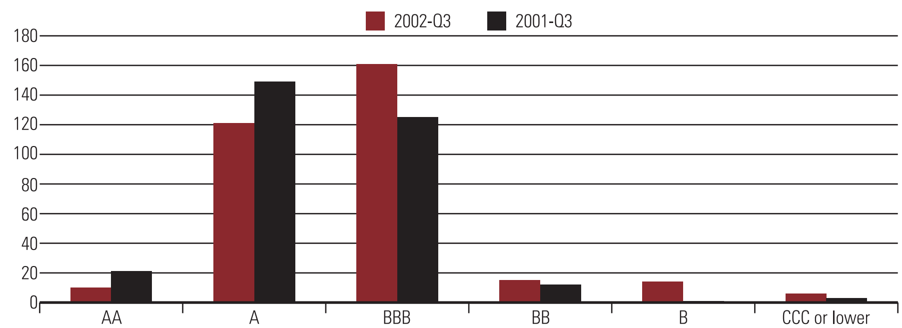
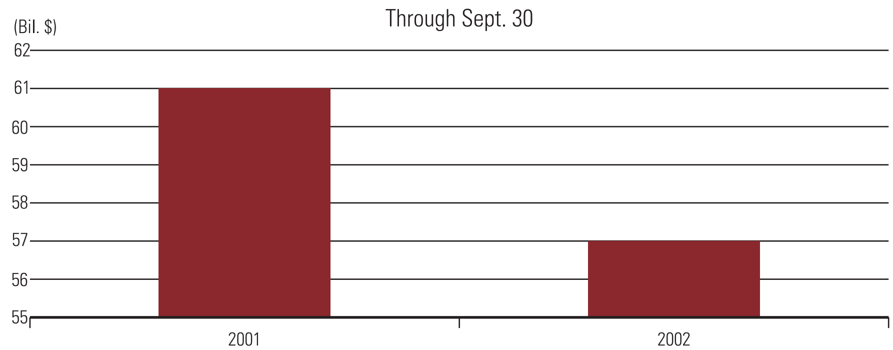


Chart 4
Debt and Preferred Stock Issuance
Through Sept. 30



Back to
Table of Contents
Next Page

materialize largely due to decreased marketing opportunities and lower power prices. Standard & Poor's again lowered the ratings to 'B+' following an analysis that cash flow deterioration continues unabated. Cash flow from Dynegy's merchant energy business is expected to decline even further because it is likely industry counterparties are engaging in only low-margin spot gas transactions, a trend that is expected to continue.

The ratings remain on CreditWatch with negative implications, reflecting lingering concerns regarding the firms' ability to access capital markets and/or execute asset sales necessary to preserve an adequate liquidity position to meet its obligations over the next 18 months. Resolution of the CreditWatch listing is predicated on Dynegy's execution of stated business objectives and its ability to meet debt maturities at a level that supports the current rating. A demonstrated ability to achieve these goals could result in ratings stability.

Ratings on Aquila Inc. and its subsidiaries were lowered due to a deteriorating financial profile stemming from its involvement in the energy marketing and trading business. The company's decision to abandon that business to focus on regulated utility operations and efforts to improve its financial condition through asset and equity sales were not sufficient to preserve its prior credit quality. The negative outlook can be attributable to the risk that the company will be unable to timely achieve the amount of asset sales necessary to pay down debt to a level appropriate for the new rating.

Kinder Morgan Energy Partners L.P.'s (KMP) ratings were lowered due to a decline in its business risk profile, as well as greater interdependence between KMP and Kinder Morgan Inc., which holds a general partnership interest in KMP. The outlook is stable.

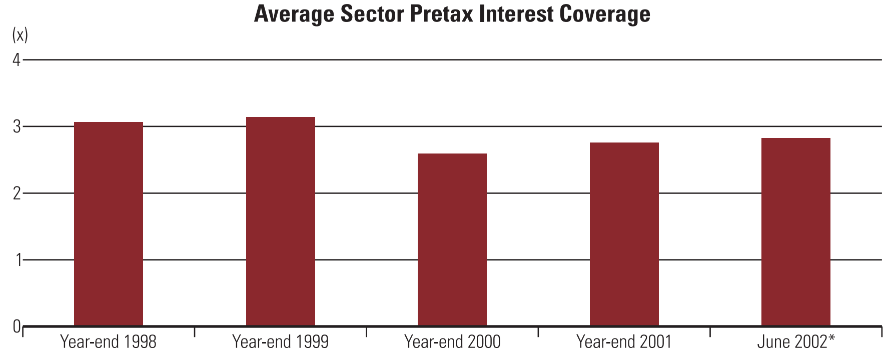
The ratings on CMS Energy Corp.'s subsidiaries Consumers Energy Co. and CMS Panhandle Pipeline Cos. were lowered to 'BB', in line with that of the parent. The downgrade reflects the company's use of the stock of subsidiary CMS Enterprises, which includes CMS Panhandle Pipeline, as security in certain bank facilities to obtain longer-term financing to weather its current liquidity position. In Standard & Poor's view, CMS Energy's actions indicate that the risk of default of CMS Energy and its affiliates is the same because the company relied on an operating subsidiary to meet its own financial commitments during a time of financial stress. The outlook is negative owing to the uncertainty posed by the SEC inquiry and CMS Energy's board of directors' special committee investigation into the round-trip trades. Additional challenges for CMS Energy include execution risk in completing planned asset sales, maintaining adequate liquidity over the near term, and generating cash flow and reducing debt sufficient enough to produce financial measures suitable for its current rating.

TECO Energy Inc. and affiliates saw their ratings lowered two notches owing to lower levels of consolidated cash flow, higher debt balances associated with commitments related to its power unit, and expected credit protection measures that are now commensurate with a 'BBB' corporate credit rating. The outlook for all entities is negative. Despite TECO's action plan and previously issued equity, depressed profitability at TECO Power Services (TPS), combined with weak power prices, presents significant challenges for the firm, including weaker interest coverages and execution risk. The outlook for all entities is negative, reflecting substantial execution risk that the company faces as it implements its action plan, and significant challenges related to activity at TPS, including construction commitments. Still, timely completion of TECO's monetization efforts, combined with successful navigation of TPS risks, could lead to ratings stability.

Allegheny Energy Inc. and its subsidiaries' ratings were lowered to 'BBB' from 'BBB+' on August 16 owing to a weakened financial profile caused by increasing debt leverage and a worse-than-expected downturn in the wholesale power market. Shortly after the close of the third quarter, Standard & Poor's again lowered its ratings to 'BB' from 'BBB' following the company's announcement that its principal credit agreements are under technical default. The ratings are on CreditWatch with negative implications, pending the outcome of the company's negotiations with its banks.

Chart 5

Average Sector Pretax Interest Coverage



*Indicates rolling 12 months.

EOTT Energy Partners L.P. experienced a several notch downgrade this quarter with its corporate credit rating slipping to 'CCC' from 'B+'. On Oct. 1, the company's ratings were lowered to 'D' reflecting its failure to make a bond interest payment. The company will be utilizing the 30-day grace period and a forbearance on its bank credit facilities to attempt to reach an agreement on restructuring its debt and to resolve outstanding issues with Enron Corp. An Enron subsidiary is the general partner of EOTT. Since those efforts have been under way for months and have yet to produce any agreements, Standard & Poor's believes it is questionable whether the company will be able to successfully settle all of the necessary issues that will allow it to resume timely payments on its debt.

Lower ratings for SCANA Corp. and affiliates South Carolina Electric & Gas Co. and Public Service Co. of North Carolina Inc. reflect the parent's high debt leverage and the fact that management's previous plan to strengthen the balance sheet is being prolonged by the company's accelerating capital program and the delay in its ability to monetize all of its Deutsche Telekom shares (currently at a lower price than expected). These factors greatly hinder the company's ability to have its key financial ratios return to former levels of credit quality that support an 'A' ratings profile. The outlook is stable.

The ratings on Peoples Energy Corp. and subsidiaries Peoples Gas Light & Coke Co. and North Shore Gas were lowered several notches owing to deterioration in parent company Peoples Energy's consolidated financial profile, coupled with increasing business risk associated with the company's unregulated activities.

UGI Corp.'s electric utility affiliate UGI Utilities Inc. saw its ratings lowered due to increasing business risk at the parent. The stable outlook mirrors that of parent UGI Corp. and reflects its ability to continue to manage the challenges of a growing propane business while adequately maintaining the utility's financial condition.

Lower ratings for Empire District Electric Co. reflect a downward trend in the company's financial profile that was not adequately stemmed in recent regulatory actions. The outlook is stable.

NRG's Precipitous Credit Decline

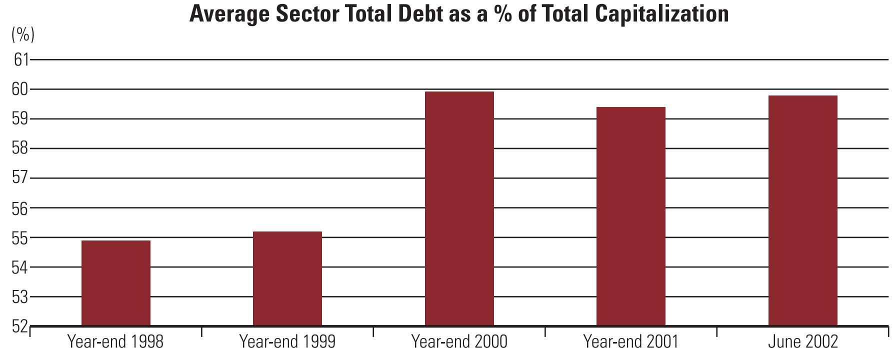
NRG Energy Inc., the independent power producer subsidiary of Xcel Energy Inc., experienced the most dire credit spiral this quarter, with its corporate credit rating lowered to 'D' from a 'BBB-'.

On June 3, 2002, Xcel completed a tender for the shares of NRG that it did not already own. Xcel's management then began to re-integrate NRG into Xcel. Xcel proposed improving NRG's financial position through significant asset sales and a cash infusion from Xcel. (Before the tender offer, NRG was rated 'BBB-', mainly reflecting its stand-alone credit quality. However, the rating always incorporated some level of implicit support from Xcel.) On June 24, 2002, Standard & Poor's lowered its corporate credit rating on Xcel and its subsidiaries, including NRG, to 'BBB'. The levelization of the ratings reflected repurchase of all NRG shares and the reintegration of the business into Xcel's corporate structure.

Notwithstanding Xcel's restructuring plan, NRG's financial position worsened as a result of low wholesale prices and a heavy debt burden. Exacerbating low operating cash flow was the uncertainty of the timing and amount of asset sales, which were not occurring quickly. NRG's own financial problems began to affect Xcel and its utility subsidiaries' access to capital. Xcel management's support for NRG accordingly began to wane, and with it Standard & Poor's perspective on the levelization of all Xcel's corporate credit ratings. Thus, Standard & Poor's undertook a series of negative rating actions on NRG alone. The downgrades were initially prompted by the poor cash flow position of NRG, and subsequently by the substantial equity calls triggered by the downgrade process (when NRG fell below investment grade, several financing arrangements required capital to be posted). As a result, NRG is currently rated purely on a stand-

Chart 6

Average Sector Total Debt as a % of Total Capitalization



Back to Table of Contents
Next Page

alone basis. On Sept. 16, 2002, NRG's corporate credit rating was lowered to 'D', reflecting a default on four separate issues of corporate and project-level debt service.

The Few Upgrades...

The ratings on LG&E Energy Corp. and its subsidiaries were raised and removed from CreditWatch. The rating action followed the July 1, 2002 acquisition of LG&E's parent company Powergen PLC group by the German utility company E.ON AG, and a review by Standard & Poor's of the operational and financial linkages between the companies. The ratings reflect LG&E's lower stand-alone credit quality, offset by the benefit of being part of the stronger E.ON group. The implied support from E.ON is based on the expectation that LG&E will play an important and long-term role in E.ON's strategy to expand its presence in the U.S. The outlook is stable and reflects the expectation that E.ON will support LG&E's funding requirements, including the refinancing of maturing debt at the E.ON level.

Higher ratings for American Transmission Co. can be traced to favorable FERC rate treatment, organizational efficiencies, and stronger financial measures. The outlook is stable owing to expectations for continued reliable operations and supportive regulation. Also, it is expected that the capital expenditure program will not stress the company's financials and that the member/owner companies will continue to support credit quality.

Mixed Rating Actions

Northern Natural Gas Co. (NNG) experienced numerous rating actions. On July 2, its ratings were raised to 'BBB-' from 'CC' due to the expiration of Enron Corp.'s option to repurchase NNG, which ensured that the firm remained a wholly owned subsidiary of Dynegy Inc. for the time being. Subsequently, on July 25, NNG's ratings were lowered to 'B+', reflecting Dynegy's inability to execute on asset divestitures, including the expected partial monetization of NNG. Because Standard & Poor's viewed the sale as being uncertain, NNG's creditworthiness was considered to be commensurate with the consolidated credit rating of Dynegy. On Aug. 23, NNG's ratings were raised back to 'BBB-' following MidAmerican Energy Holdings Co.'s closing on the purchase of the pipeline from Dynegy. Lastly, on Sept. 25, 2002, NNG's ratings were raised three notches to 'A-' following its change of ownership. NNG is now a wholly owned subsidiary of NNGC Acquisition LLC, which in turn is a wholly owned subsidiary of MidAmerican Energy Holdings. Because of a ring-fencing structure that protects NNG from credit events at the MEHC parent, the rating on NNG is higher than that of its parent. The outlook is stable.

CreditWatch Listings Heat Up

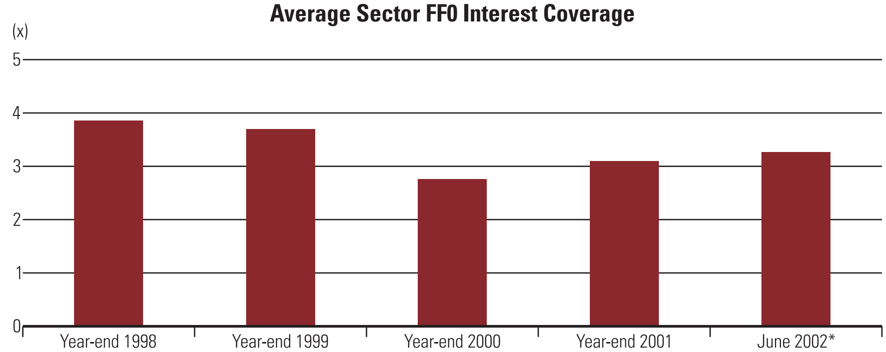
Following a revision in its credit outlook to negative from stable early in August, the ratings on El Paso Corp. and its affiliates were placed on CreditWatch with negative implications on Sept. 23 as a result of the FERC Administrative Law Judge's recommendation that fines be imposed for withholding capacity and exercising market power in California. Standard & Poor's will review the firm's response to regulatory pressures, as well as 2003 projected cash flow and capital spending at the pipeline, exploration and production units, and gathering and processing units. The potential for lower credit ratings is possible after Standard & Poor's review, which will be completed before the end of 2002.

The ratings on Cleco Corp. and its utility, Cleco Power LLC, were placed on CreditWatch with negative implications to reflect the worsening credit quality of the counterparties in the company's tolling agreements and financing risk associated with the Acadia power project.

The tolling agreement with Williams Energy Marketing on Cleco's Evangeline project could be affected by the eroding credit quality at The Williams Cos. Inc., which is deeply speculative grade. Cleco also has tolling agreements with other counterparties that are experiencing deteriorating creditworthiness, which could affect the expected cash flows from the projects that contribute support for Cleco's

Chart 7

Average Sector FFO Interest Coverage



*Indicates rolling 12 months.

Back to Table of Contents
Next Page

current ratings. Cross-default provisions in Cleco's corporate credit facility may also be triggered by credit events at one or more of the power projects.

Current ratings are also predicated on the completion of nonrecourse financing of the Acadia power project, which is questionable. If Acadia-related debt remains fully recourse to Cleco, credit protection measures for Cleco would not support current ratings.

Resolution of the CreditWatch listing will occur when the impact of the credit deterioration at Williams on the Evangeline project becomes clearer and when substantial progress has been achieved in Acadia's re-financing.

Nicor Inc. and subsidiary Nicor Gas Co. had their ratings placed on CreditWatch with negative implications following accounting problems and losses related to the Nicor's 50% ownership in Nicor Energy LLC, a retail energy marketing joint venture with Dynegy Inc., possible improper behavior in the company's performance-based rate program, and the immediate and severe negative market reaction to the company's announcements. Although the losses recorded are mainly noncash, relatively small for the consolidated entity, and have not affected the company's robust financial profile and solid liquidity position, the potential for further disclosures could result in subsequent charges and restatements.

The ratings on Pennsylvania Suburban Water Co. were placed on CreditWatch with negative implications owing to parent Philadelphia Suburban Corp.'s agreement to purchase AquaSource Utility Inc., a DQE Inc. subsidiary, for $205 million. The transaction is expected to close in the second half of 2003. Of credit concern is the potential for consolidated financials to weaken if the transaction is largely debt-financed.

More Negative Outlooks

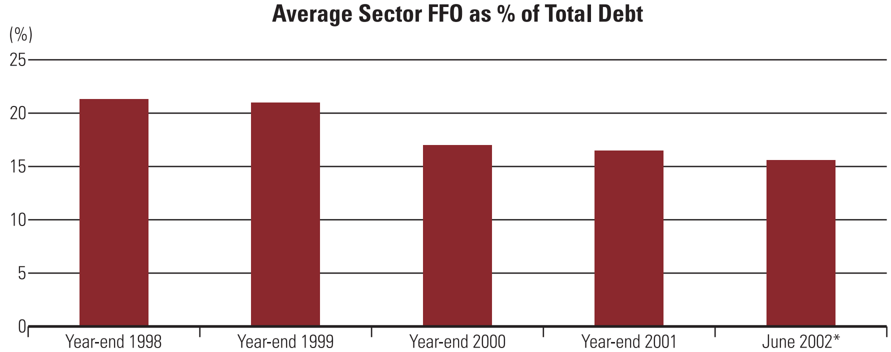
PPL Corp. and its subsidiaries, except PPL Electric Utilities which is structurally ring-fenced, had their outlooks changed to negative from stable, reflecting PPL's deteriorating credit profile that has resulted primarily from declining wholesale electricity prices and also from setbacks in its international operations, particularly in Brazil. PPL's management will also have to balance the level of debt financing in its capitalization with the pace of its growth strategy.

The credit outlook on TXU Corp. was revised to negative from stable, reflecting a deterioration in TXU Europe Ltd.'s creditworthiness. TXU Europe represents about one-third of TXU Corp.'s global income and has more than one-half of all its customers. TXU Australia Holdings (Partnership) L.P., which represents a much smaller percentage of assets and customers, is also highly leveraged. The ratings of both subsidiaries benefit from the relatively strong cash flow and improving financial profile of TXU US Holdings, which owns the electric and gas distribution businesses in Texas. TXU US Holdings will reduce debt by over $1 billion when securitized in 2003 and 2004. Debt is also being reduced with proceeds from the sale of generating plants in the U.K. and Texas, and from the issuance of common stock and convertible debt. Debt will continue to be reduced using cash flow and the conversion of existing securities. However, with the diminished prospects for profitability in Europe, and the likelihood of limited returns from the Australian operations in the short-to-medium term, it is less likely that strengthening financials in the U.S. will be sufficient to support the current corporate credit rating for the consolidated company.

The ratings on Puget Energy Inc. and subsidiary Puget Sound Energy Inc. (Puget) were affirmed and removed from CreditWatch, reflecting an agreement among various parties to Puget's interim and general rate requests. Recent resolution of the utility's general rate case with the Washington Utilities and Transportation Commission is considered by Standard & Poor's to be supportive of Puget's credit quality. Yet, the outlook is negative owing to weak financial measures and concern that Puget Energy and the utility might not be able to achieve current projections, which indicate that both entities should achieve financial targets commensurate with current ratings by 2004 and 2005.

Chart 8

Average Sector FFO as % of Total Debt



*Indicates rolling 12 months.

Rating Stability

The ratings on Northwest Natural Gas Co. were removed from CreditWatch with negative implications, where they were placed Oct. 8, 2001, following the company's announcement that it agreed to purchase Portland General Electric Co., a unit of Enron Corp. On May 17, 2002, Enron and Northwest Natural mutually agreed to terminate the contract following Enron's inability, following its bankruptcy, to satisfy the terms of the contract as originally agreed upon. The sale contract's termination was subject to bankruptcy court approval, which was formally given on June 20, 2002 and was effective July 1, 2002. The outlook is stable.

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Research:

Industry Report Card: U.S. Electric/Water/Gas

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Commentary/Key Trends

Rating actions in the regulated U.S. utility (electric, gas, pipeline, and water) and merchant power sectors over the past few months were fairly balanced. Since the last report card (for the third quarter of 2004), there were nine upgrades and eight downgrades.

A few noteworthy trends have emerged as important factors for credit quality. These include the rising importance of regulatory decisions in certain states, the acceleration of merger and acquisition activity, a low interest rate regimen, and attractive debt capital markets that allow many issuers to refinance at favorable rates. Despite these trends, challenges associated with weak financial credit measures and stagnant power markets in many regions pressure the financial performance of certain issuers.

Regulatory treatment has become a more prevalent ratings driver in certain jurisdictions. Filings and rulings on rate proceedings in states such as Arizona, Oregon, Missouri, and Texas could affect ratings in the near term. In addition, the opposing views of certain state regulatory bodies and the FERC on issues, such as restructuring the regional transmission systems and incorporating certain merchant plants of affiliated companies in the rate base, will likely lead to a protracted struggle among those regulatory bodies for oversight.

Regulatory decisions were meaningful factors in the downgrades of DTE Energy Co. (BBB/Stable/A-2) and IDACORP Inc. (BBB+/Stable/A-2). In the case of IDACORP, a disappointing regulatory decision compounded by weak credit measures led to the downgrade. For Detroit Edison Co., a unit of DTE Energy, despite the granting of a rate order that provided a substantial increase in rates and contained many favorable characteristics, the credit measures would not improve enough in the near term to be commensurate with the ratings.

Another development that has become a more prominent ratings issue is merger and acquisition activity. Recently, Exelon Corp. (A-/Watch Neg/A-2) announced a merger with Public Service Enterprise Group Inc. (BBB/Watch Dev/A-3) that would create the industry's largest utility holding company. Exelon's ratings were placed on CreditWatch with negative implications while PSEG's ratings were placed on CreditWatch with developing implications. The ratings on NUI Utilities Inc. (A-/Negative/--) and the outlook on AGL Resources Inc. (A-/Negative/A-2) were also affected by their transaction, which was completed in December. In addition, Illinois Power Co. (A-/Negative/--) was upgraded, upon the completion of its acquisition by Ameren Corp. (A-/Negative/A-2). While it is unclear whether these transactions presage a rise in merger and acquisition activity, there apparently is increasing interest.

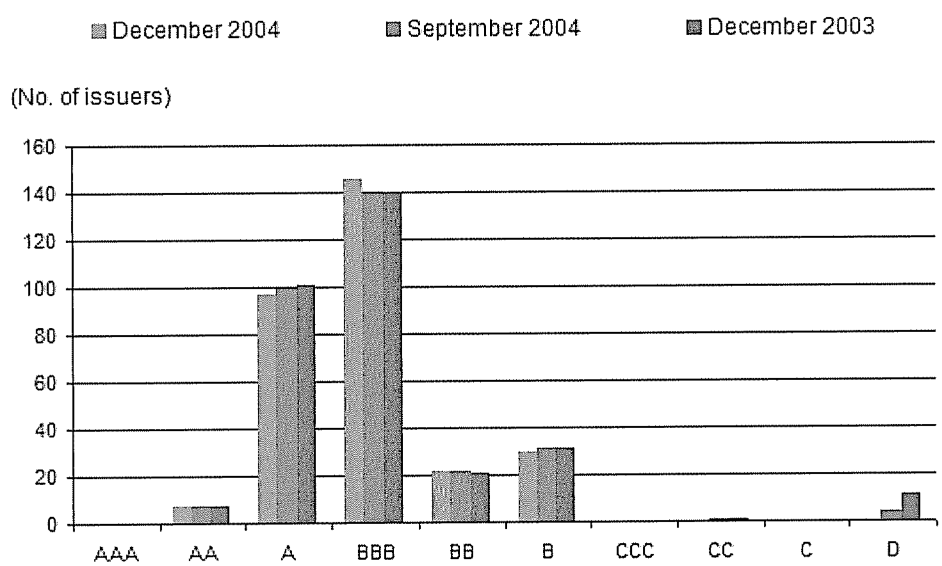
The number of rating actions during 2004 declined dramatically from the past few years. The number of rating actions (upgrades and downgrades) is only about one-third of the previous two years. This is indicative of a measure of rating stability, which is indeed apparent in rating outlooks, 56% of which are stable. This is also a reflection of slowly stabilizing credit measures as many management teams have made "balance sheet repair" a key business objective. For example, Duke Energy Corp.'s outlook was revised to positive in recognition of significant debt reduction in 2004 and improved credit measures.

Still, weak credit measures and financial performance leave certain issuers susceptible to rating downgrades. The existing financial weakness of many utilities results primarily from high debt levels and cash flow stress associated with unsuccessful forays into more competitive businesses. Consequently, 37% of rating outlooks are negative or on CreditWatch with negative implications. Moreover, despite the current industry trend of "back-to-basics," it is very possible in the longer term that the competition for capital and investor interest will embolden companies to embrace growth strategies that could erode credit quality.

Companies with merchant exposure continue to experience volatile cash flows and regulatory uncertainty. The operating environment remains challenging. The creditworthiness of many purely merchant power companies is constrained by burdensome debt levels and insufficient cash flow from operations. Faced with the prospect of stagnant power markets in many regions, cash flow measures are likely to remain weak until wholesale electricity margins materially improve. The only bright spot in this otherwise dim market are merchant coal and nuclear plants that are benefiting from their lower cost of generation in markets, where elevated gas prices set power prices.

Chart 1

U.S. Utilities Long-Term Ratings Distribution



Note: Dates represent current and previously published report card data.

Moody's Investors Service

Global Credit Research
Credit Opinion
1 MAR 2006

Credit Opinion: PacifiCorp

PacifiCorp

Portland, Oregon, United States

Ratings

Category	**Moody's Rating**
Outlook	Stable
Issuer Rating	Baa1
First Mortgage Bonds	A3
Senior Secured	A3
Senior Unsecured MTN	Baa1
Subordinate Shelf	(P)Baa2
Preferred Stock	Baa3
Commercial Paper	P-2
Parent: Scottish Power plc	
Outlook	Stable
Issuer Rating	Baa1
Sr Unsec Bank Credit Facility	Baa1
Senior Unsecured	Baa1
Utah Power & Light Co	
Outlook	Stable
Preferred Stock	Baa3

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Key Indicators

PacifiCorp

	LTM Q3 2006	2005	2004	2003
Funds from Operations / Adjusted Debt [1]	18.9%	18.2%	20.7%	17.7%
Retained Cash Flow / Adjusted Debt [1]	14.2%	14.0%	16.8%	17.7%
Common Dividends / Net Income Available for Common	69%	77%	66%	0%
Adjusted Funds from Operations + Adjusted Interest / Adjusted Interest [2]	3.83	3.97	4.12	3.54
Adjusted Debt / Adjusted Capitalization [1][3]	54.0%	57.6%	55.4%	56.6%
Net Income Available for Common / Common Equity	7.9%	7.5%	7.5%	4.2%

[1] Debt is adjusted for operating leases, guaranteed preferred beneficial interests in company's junior sub, and debentures & preferred stock subject to mandatory redemption. [2] Adjusted Interest reflects adjustments for operating leases and preferred stock dividends. [3] Adjusted Capitalization reflects the adjusted debt.

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Rationale

The Baa1 senior unsecured rating of PacifiCorp reflects expected credit metrics that are consistent with a Baa1 rating for a vertically integrated utility with PacifiCorp's risk profile under Moody's industry rating methodology (please refer to Rating Methodology: Global Regulated Electric Utilities, March 2005) and in comparison to similar companies. Key financial metrics include the ratio of adjusted funds from operations (FFO) to total adjusted debt that has averaged about 19% for the past three years, and the ratio of FFO to interest expense that has averaged about 4.0x during the same period.

The rating incorporates the belief that, following the acquisition of PacifiCorp by MidAmerican Energy Holding Company's (MEHC) from Scottish Power plc, MEHC will manage PacifiCorp's business, including its future capital structure, in a way that is supportive to credit quality, including the contribution of ongoing equity to support the utility's capital expenditure program. The rating also considers MEHC's longer-term investment horizon, and recognizes its experience in operating several regulated utility systems in different geographic regions.

Of additional importance to PacifiCorp's ratings are the legal and regulatory factors that are expected to significantly insulate the credit quality of PacifiCorp from the credit quality of MEHC as its new parent. In this regard, key provisions include the appointment of an independent director, the regulatory requirement that a minimum common equity level that ranges between 44.0% and 48.25% be maintained to allow distributions, and a prohibition on the payment of dividends if PacifiCorp's senior unsecured debt ratings fall below investment grade.

The rating incorporates the expectation that PacifiCorp will continue to receive reasonable regulatory treatment throughout its six-state jurisdiction for the recovery of supply and delivery-related capital investment and operating costs. PacifiCorp's relatively stable financial performance has been aided by generally supportive regulatory decisions for capital investment and for recovery of power procurement costs. However, PacifiCorp has numerous remaining regulatory challenges in several of its key jurisdictions, the outcome of which could impact future credit quality at the utility. Of particular near-term importance is the outcome of several outstanding regulatory and legislative issues in Oregon. Operating revenues from Oregon jurisdictional customers represent about 30% of PacifiCorp's operating revenues. These issues include the rehearing of PacifiCorp's September 2005 Oregon general rate case (GRC), which substantially reduced the recommended rate increase by incorporating terms of the recently enacted tax-related legislation (Senate Bill 408) into the decision, the outcome of permanent rulemaking concerning the implementation of Senate Bill 408, and a final decision of the company's recently filed GRC.

The rating recognizes that the major regulatory impediments to the acquisition of PacifiCorp by MEHC appear to have been satisfied and that the acquisition is now expected to take place in the next 30 days. The transaction has been formally approved by the regulators of all six states that regulate PacifiCorp's utility operations. The transaction has also been approved by the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission and the Department of Justice. Each of the state regulatory authorities has an opportunity for final review, particularly for "most favored states" consideration of approval conditions that were imposed by other jurisdictions.

Rating Outlook

The rating outlook is stable reflecting an expectation of fairly supportive regulatory decisions and a conservatively financed capital investment program

The rating outlook also recognizes that the acquisition, when completed, will eliminate an overhang of uncertainty that resulted from Scottish Power's clear intention to divest PacifiCorp.

What Could Change the Rating - UP

While the size of the company's capital expenditures limits the prospects for a rating upgrade at PacifiCorp in the near-term, the rating could be upgraded if reasonably regulatory support and a conservatively financed capital expenditure program results in a sustained improvement in credit metrics. This would include PacifiCorp's FFO to total adjusted debt being in excess of 20% and its FFO to adjusted interest expense being in excess of 4.0x both on a sustainable basis.

What Could Change the Rating - DOWN

The rating could be downgraded if reasonable regulatory support does not continue or in the unlikely event that the acquisition by MEHC is not consummated resulting in substantial uncertainty about the future ownership of PacifiCorp, given SP's stated desire to sell the utility.

This Analysis provides a discussion of the factors underpinning the credit rating/s and should be read in conjunction with our Credit Opinion. The most recent ratings, opinion, and other research specific to this issuer are provided on Moodys.com. Click here to link.

Analysis

UNITED STATES
Americas

June 2005

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PacifiCorp

PacifiCorp is a regulated utility serving retail customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho, and California. As a vertically integrated utility, PacifiCorp owns and has contracts for fuel sources including coal and natural gas and uses these fuel sources, as well as other fuel sources, including wind, geothermal, and hydro, to generate electricity at its power plants. PacifiCorp conducts its retail electric utility business under the names Pacific Power and Utah Power, and sells excess electricity generation in the wholesale power market. Sales to retail customers in Utah and Oregon represent about 70% of PacifiCorp's total retail revenues.

PacifiCorp's fiscal year ends on March 31st. During fiscal year 2005, the company's total revenues reached $3.048 Billion and its net income was $251.7 million. PacifiCorp is an indirect wholly-owned subsidiary of Scottish Power plc (SP: Baa1 senior unsecured).

On March 23, 2005, SP executed a Stock Purchase Agreement with MidAmerican Energy Holdings Company (MEHC) providing for the sale of the common stock of PacifiCorp for approximately $9.4 Billion, consisting of $5.1 Billion in cash plus the assumption of approximately $4.3 Billion in net debt and preferred stock. The sale requires SP shareholder approval and will require numerous state and federal regulatory approvals. The company anticipates the sale will be completed during calendar year 2006.

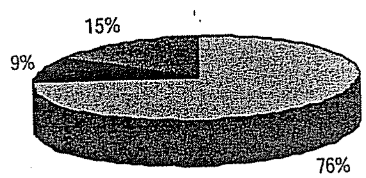
Moody's Investors Service
Global Credit Research

Low-cost generating assets and extensive transmission network through the western US

PacifiCorp owns or has access to low cost generating assets, the bulk of which is coal-fired assets. Mines owned by PacifiCorp provide about 30% of PacifiCorp's coal needs, with the remainder being sourced by long-term and short term contracts. PacifiCorp's owned generation satisfied 79% of the utility's 2005 energy needs, with the remaining 21% being satisfied by short-term and long-term purchases.

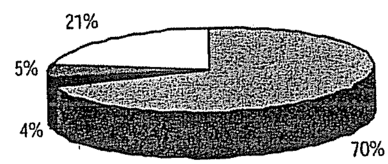
In addition to the company's low-cost generation resources, the company owns or has access to an extensive transmission system covering 15,530 miles throughout the Pacific Northwest. Access to this multi-state system favorably positions PacifiCorp in the wholesale power market to secure or to sell excess capacity as needed.

PacifiCorp Owned Generation



Source: PacifiCorp 2005 10-K

PacifiCorp's Energy Requirements 2005



Source: PacifiCorp 2005 10-K

Recent key regulatory decisions have been constructive

For the past several years, PacifiCorp has been actively seeking regulatory support across the company's six-state jurisdiction in an effort to enhance returns at the utility. To date, PacifiCorp's efforts have been reasonably successful. #2

In Utah, which represents about 40% of total retail revenues, the Utah Public Service Commission (UPSC) approved, in February 2005, a stipulated settlement of the company's general rate case awarding an increase of $51 million annually, based upon a return on equity of 10.5%. Additionally, in October 2004, the UPSC approved the use of a forward-looking test year, which was implemented for the first time in the company's general rate case, and helps to support the company's credit fundamentals while it finances its large capital investment program. Also, in Utah, the state passed Senate Bill 26 in February 2005. Among other things, this bill provides PacifiCorp with the opportunity to obtain advance approval from the UPSC of resource decisions and an assurance of recovery of costs associated with the resource.

In Oregon, which represents slightly less than 30% of total retail revenues, the Oregon Public Utility Commission (OPUC) approved, in July 2002, recovery of the company's deferred accounting filing relating to excess net power costs. The order authorized recovery of $131.6 million, plus carrying costs, at a rate of $45.6 million annually.

Financing plan contemplates substantial equity support

PacifiCorp's capital expenditure program is expected to be more than $1 billion in each of the next two years. PacifiCorp intends to finance this program with a combination of internally generated funds, the issuance of long-term debt, and substantial equity support from indirect parent, SP. To that end and pursuant to the Stock Purchase Agreement, SP is required to contribute $125 million per quarter during 2006 and $131.25 million per quarter during fiscal year 2007. If the sale of PacifiCorp is completed, MEHC will refund to SP the amount of required fiscal 2007 common equity contributions as an increase to the purchase price. Moreover, pursuant to the Stock Purchase Agreement, SP has agreed to cause PacifiCorp to not pay dividends in excess of $53.7 million per quarter during 2006 and in excess of $60.575 million per quarter during 2007.

While credit metrics lag relative to similarly rated peers, rate increases have strengthened credit metrics

PacifiCorp's credit metrics, while improving since 2001 and 2002, continue to remain weak when compared to other similarly rated vertically integrated utilities. For example, funds from operations (FFO) to total adjusted debt averaged slightly less than 20% over the last two years, while PacifiCorp's FFO coverage of adjusted interest expense averaged near 4.0x. Given the size of the company's capital investment program along with the number of rate requests outstanding, reasonable regulatory support over the next several years coupled with a fairly conservative capital structure will be the two biggest drivers of PacifiCorp's near-term credit quality.

Six state utility network creates regulatory challenges

Among the largest challenges for PacifiCorp is managing the regulatory relationships of six different state commissions. Since 2002, the company has been involved in designing and implementing a cost allocation methodology that would achieve a more permanent consensus on the allocation of costs across the six state service territory. In March 2005, final ratification of the revised protocol for cost allocations was approved in four of the six states--Utah, Oregon, Wyoming, and Idaho. In Washington, the commission accepted the revised cost allocation protocol for reporting purposes and established a process for ongoing discussions that could lead to a permanent allocation methodology during fiscal 2006. In California, the revised protocol will be filed in the company's next general rate case.

Regulatory uncertainty still remains due to numerous rate applications pending

While PacifiCorp has achieved a reasonable level of success in obtaining important rate relief throughout the company's six state service territory, challenges remain given the number of pending requests outstanding.

In Oregon, PacifiCorp filed a general rate case in November 2004 with the OPUC related to increases in operating costs, including fuel, purchased power, and pension and health care costs. PacifiCorp is seeking an increase of $102.0 million annually. If approved by the OPUC, the increase would take effect in September 2005. Several parties have reached a partial stipulation with PacifiCorp that would reduce the proposed revenue requirement increase in the case from approximately $102 million to approximately $71 million. The partial stipulation covers many items including net power costs but certain items, including cost of capital, pensions and benefits are still being litigated. Hearings are scheduled to occur in July 2005.

Also, in Oregon, PacifiCorp filed an application in February 2005 for deferral of higher power costs in calendar 2005 due to continuing poor hydroelectric conditions. On May 25, 2005, this deferral application was suspended to allow the parties to focus on the power cost adjustment mechanism filed by PacifiCorp in April 2005. If approved, the proposed power cost adjustment mechanism will address Oregon's share of PacifiCorp's total net power cost volatility resulting from such factors as hydroelectric, natural gas and load variability. The proposed power cost adjustment mechanism is designed to be a longer-term, ongoing mechanism that passes through to customers a portion of excess net power costs or returns to customers a portion of over-collected net power costs, keeping rates more closely aligned with PacifiCorp's actual costs.

Deferral Fcl

In Wyoming, the Wyoming Public Service Commission (WPSC) approved a joint stipulation increasing rates by $9.3 million annually, effective September 15, 2004. As part of this stipulation, PacifiCorp agreed not to file a general rate application until at least September 30, 2005. Further, the parties agreed to hold discussions on the development of a commodity cost recovery mechanism and alternative forms of regulation. Discussions on both topics are underway.

In Washington, PacifiCorp filed an application in March 2005 for the deferral of higher power costs in 2005 due to poor hydroelectric conditions. PacifiCorp requested that the deferral continue through the conclusion of the general rate proceeding. As part of that proceeding, PacifiCorp expects to address the rate treatment of the current low hydroelectric trend and power cost volatility through a proposed power cost adjustment mechanism.

Also, in Washington, PacifiCorp, on May 5, 2005, filed a general rate case request with the Washington Utilities and Transportation Commission (WUTC) for approximately $39.2 million related to increases in operating costs, including fuel, purchased power, pension and other employee benefit costs. The rate increase also addresses investment in new generation, the implementation of a power cost adjustment mechanism and ratification of the multi-state process protocol discussed above that has been adopted by four other states served by PacifiCorp. PacifiCorp is seeking an allowed rate of return on equity of 11.125%.

In Idaho, PacifiCorp, on January 14, 2005, filed a general rate case with the Idaho Public Utility Commission (IPUC) related to continuing investment to serve Idaho load, increases in employee-related costs and general inflation impacts. PacifiCorp is seeking an increase of $15.1 million annually. If approved by the IPUC, new rates would take effect September 16, 2005.

While the potential acquisition of PacifiCorp by MEHC has long-term benefits, near-term regulatory challenges could surface as the merger-related approval process could affect the timing and the outcome of a number of existing rate cases

Following the announcement that MEHC would purchase the stock of PacifiCorp from SP, Moody's changed the rating outlook for PacifiCorp to developing from stable. The change in rating outlook incorporates the view that, while the acquisition of PacifiCorp by MEHC may have long-term positive benefits, particularly given the size of the capital investment program, new near-term regulatory challenges may surface as the merger-related approval process in each of the six states could affect the timing and the outcome of a number of important rate cases that are underway. As discussed above, most of the current rate cases have the potential for PacifiCorp to obtain some form of rate increase, which collectively will enhance the company's returns and cash flow as the utility increases its capital investment. To the extent that the merger approval process substantially affects the timeliness or the amount of rate recovery currently being pursued by PacifiCorp, the company's credit quality could, in the near-term, be negatively affected.

This near-term concern is balanced against the longer-term benefits to PacifiCorp's bondholders of ownership by MEHC, which is 80.5% owned by Berkshire Hathaway, and considers MEHC's successful track record in operating other regulated utility businesses as well as Moody's belief that the potential new owners are likely to take a long-term view towards enhancing returns at PacifiCorp.

Moody's intends to monitor the merger approval process at the state and federal level and assess the impact, if any, on PacifiCorp's existing regulatory filings, as well as the final form in which MEHC intends to finance this acquisition. To the extent that the merger related regulatory proceedings do not meaningfully affect the timeliness or the outcome of state regulatory proceedings currently underway, the PacifiCorp rating outlook could stabilize.

While the size of the company's capital expenditures limit the prospects for a rating upgrade at PacifiCorp in the near-term, the rating could be upgraded over the intermediate term if the company's capital expenditure program continues to be financed conservatively and if reasonably regulatory support is secured on a timely basis resulting in an improvement in credit metrics. This would include PacifiCorp's funds from operations (FFO) to total adjusted debt being in excess of 20% on a sustainable basis and its FFO to adjusted interest expense being comfortably in excess of 4.0x on a sustainable basis.

Future capital expenditures will increase materially

Depicted below are the actual capital expenditures for the year ended March 31, 2005, as well as PacifiCorp's estimated capital expenditures for the years ending March 31, 2006 and 2007.

(Millions of dollars)	Actual Year Ended Years Ending March 31,	Estimated Years Ending March 31,	
	2005	2006	2007
Distribution and Transmission	$324.2	$369.5	$436.8
Generation and Mining	482.6	634.7	497.9
Other	44.8	78.2	124.5
Total	$851.6	$ 1,082.4	$1,059.2

Source: PacifiCorp 2005 10-K

Actual and estimated future capital expenditures include upgrades to distribution and transmission lines, upgrades of generating plant equipment, connections for new customers, facilities to accommodate load growth, coal mine investments, air-quality and environmental expenditures, hydroelectric relicensing costs and information technology systems. In addition, these estimates include the remaining costs related to the Currant Creek Power Plant (Currant Creek) and the costs to have the Lake Side Power Plant (Lake Side) developed and constructed to meet customer resource needs in summer 2007.

Financial performance can be affected by hydro levels in the Pacific Northwest

Like other utilities in the Pacific Northwest that rely upon hydroelectric energy, PacifiCorp's year-to-year financial results can be impacted. The current lower than normal hydro levels have caused PacifiCorp to become more dependent on higher costs alternatives, including wholesale purchases or generation from its own fossil fuel resources. PacifiCorp is addressing this issue on two fronts. For one, the company is building two natural gas-fired power plants, Currant Creek and Lake Side, which when completed, will better balance loads and resources, particularly during peak periods of the year. Additionally, the company is seeking a permanent commodity adjustment clause in a number of its state jurisdictions, which if obtained, would strengthen the predictability of year-over-year cash flow currently caused, in part, by changes in hydroelectric conditions.

CUB-ICNU/403
Gorman/20

STANDARD &POOR'S | RATINGSDIRECT

Exhibit ICNU Set 7
DR 7.63(f)

RESEARCH

Credit FAQ: MidAmerican's Acquisition Of PacifiCorp--Implications For PacifiCorp's Bondholders

Publication date: 21-Mar-2006
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MidAmerican Energy Holdings Co. (MEHC; A-/Stable/--) today closed its acquisition of PacifiCorp. (A-/Stable/A-2). MEHC purchased all of PacifiCorp's outstanding shares for about $5.1 billion in cash from Scottish Power plc (A-/Stable/A-2), which was funded from an investment by its parent, Berkshire Hathaway Inc. (AAA/Stable/A-1+). Subsequent to the purchase, MEHC is expected to repurchase $1.7 billion of Berkshire Hathaway's common stock in MEHC. PacifiCorp's long-term debt and preferred stock, which stood at about $4.1 billion as of Dec. 31, 2005, remains outstanding.

On March 6, in anticipation of the transaction being completed, Standard & Poor's affirmed the 'A-' corporate credit rating (CCR) on PacifiCorp and removed its ratings from CreditWatch with negative implications. The outlook is stable. This article addresses in further detail the acquisition from the perspective of PacifiCorp's bondholders and discusses the expected ramifications of the sale on PacifiCorp's future credit quality.

Frequently Asked Questions

How has PacifiCorp's financial performance been in recent years?

PacifiCorp's credit quality has benefited from the otherwise strong consolidated operations of Scottish Power, which purchased the utility in 1999 for $10.7 billion. On a standalone basis, financial performance has been weak but recovering. Scottish Power purchased PacifiCorp just prior to the western U.S. energy crisis, which, given the company's sizable short position as well as unplanned outages, resulted in deferred power costs of approximately $525 million, of which about $325 million was ultimately authorized for recovery in retail customer rates. Since then, the company has struggled to achieve cash flows commensurate with performance seen before the crisis. Funds from operations (FFO) has only stabilized in the last two fiscal years to levels on par with fiscal 2000, when FFO was $728 million; for the 12 months ending Dec. 31, 2005, FFO improved to about $818 million. Earned return on equity (ROE), which has been around 7% in the past two years, has fallen chronically short of authorized levels, which range from 10%-10.5%, depending on the state. With respect to cash coverage metrics, PacifiCorp's 12 months ending Dec. 31 adjusted FFO to interest coverage was 3.5x, with adjusted FFO to total debt at 17.1%. Adjusted debt to total capitalization was 56%. These ratios consider PacifiCorp's substantial purchased power obligations, which contributes to off balance sheet adjustments of $537 million for the purposes of credit ratio calculations.

Multiple factors contributed to PacifiCorp's weakened financial performance over the last five years, and include the absence of fuel and purchase adjusters, except in Wyoming, where one was approved in February 2006; dry hydro conditions; increasing administrative and general costs, including escalating pension and health care costs; and regulatory lag in resolving sizable general rate cases. In addition, Scottish Power has projected that PacifiCorp requires $6.4 billion in capital expenditures over the next five years, which would have likely necessitated higher leverage at the parent to support the utility's infrastructure needs. These factors resulted in Scottish Power's decision in May 2005 to sell PacifiCorp.

Given these issues, why did MEHC buy PacifiCorp?

Berkshire Hathaway has sizable amounts of equity to invest, and has identified regulated utility assets as desirable because of the opportunity to deploy its capital in return for what the company expects will be reasonable and stable returns. PacifiCorp is also attractive because of its earnings upside if MEHC can improve actual ROEs to allowed levels.

The acquisition should fit well with MEHC's existing energy holdings, which are predominately in the regulated space and consist of MidAmerican Energy Co. (MEC; A-/Stable/A-1), an Iowa-based utility that serves 1.3 million electric and gas customers; CE Electric U.K. Funding Co. (BBB-/Stable/A-3), which serves 3.7 million electric customers (via the distribution companies of Yorkshire Electricity and Northern Electric); and two U.S. pipelines, Kern River Gas Transmission Co. (A-/WatchNeg/--)and Northern Natural Gas Co. (A/Stable/--) that are under the jurisdiction of the FERC. In 2005, these regulated entities contributed about 78% of MEHC's earnings (MEC was 26%, the U.K. operations were 25%, and the two pipelines accounted for 27%). MEHC's largest unregulated subsidiary is a real estate brokerage firm, HomeServices (not rated), which in 2005 provided about 13% of earnings. Through various subsidiaries, MEHC also owns additional independent power generation facilities, including hydroelectric and geothermal assets in the Philippines. Collectively, these unregulated energy companies contributed about 9% of 2005 earnings.

Despite the significant number of companies under MEHC, PacifiCorp is a sizable acquisition. The company operates under the legal names of Pacific Power and Utah Power, serving 1.6 million retail customers in six western U.S. states. Its total assets were $12.8 billion at year-end 2005, and at the 12 months ending Dec. 31, 2005, cash flow from operations was nearly $900 million. In comparison, MEHC's total asset value was $20.2 billion in 2005, and cash flow from operations was $1.3 billion.

Going forward, about 35% of MEHC's operating income is expected to come from PacifiCorp. PacifiCorp will push the proportion of MEHC's operating income earned from regulated businesses to about 91% by 2007. The acquisition also provides MEHC with substantial U.S. market and regulatory diversification. The majority of MEC's retail revenues are from customers in Iowa, but the utility also operates in portions of Illinois, South Dakota and Nebraska. PacifiCorp's territories include parts of Utah, Oregon, Wyoming, Washington, Idaho, and California. As shown in Table 1, while PacifiCorp's sales are concentrated in Utah and Oregon, on a consolidated MEHC basis, the importance of each U.S. market is relatively well balanced, and thus lacks the regulatory and market concentration that most U.S. utilities are exposed to.

Table 1 MEHC U.S. Utility Market Concentration*

	% of 2005 Retail Revenues		
	MidAmerican Energy Co.	PacifiCorp Standalone	MEHC Consolidated
Iowa	83.91	0.00	42.56
Illinois	9.93	0.00	5.04
South Dakota	5.78	0.00	2.93
Nebraska	0.38	0.00	0.19
Utah	0.00	41.13	20.27
Oregon	0.00	28.71	14.15
Wyoming	0.00	13.42	6.62
Washington	0.00	8.56	4.22
Idaho	0.00	5.82	2.87
California	0.00	2.36	1.16
Total	100.00	100.00	100.00

*Excludes FERC-regulated assets owned by Kern River Gas and Northern Natural

Can MEHC improve PacifiCorp's performance?

This is certainly management's intent. Ultimately, MEHC's success will be driven by whether it can achieve greater operational efficiencies and enhance PacifiCorp's existing regulatory relationships. These goals are not dissimilar from those of Scottish Power when it purchased PacifiCorp seven years ago. However, Scottish Power's acquisition of PacifiCorp proved untimely and largely beyond its control--the unexpected events of the western U.S. power crisis resulted in the need to immediately appeal to state regulatory commissions for rate relief. Yet PacifiCorp, as with many U.S. utilities, expected the deregulation of generation would inevitably minimize the role of regulation and had not been before its regulatory bodies in some time. In addition, Scottish Power, while achieving some significant regulatory milestones, perhaps underestimated the complexities of managing six separate regulatory environments from its Glasgow, Scotland headquarters.

MEHC has a reputation as a competent operator of utility assets, and it has improved the financial performance of regulated businesses that it has acquired, most notably, MEC, which it purchased in 1999, and Northern Natural Gas, which it purchased from Dynegy in 2002, shortly after Dynegy had purchased it from Enron. In both of these businesses, MEHC cut costs, improved operations, built customer relationships and has had constructive regulatory relationships. In Northern Natural's case, it recently entered long-term extensions with two major customers, and MEC has consistently performed well in J.D. Power & Associates customer satisfaction studies. Standard & Poor's also views MEC's regulatory compact as supportive of credit quality. MEC has agreed not to request a general increase in rates before 2012 unless its Iowa jurisdictional electric ROE falls below 10%. The Iowa Office of the Consumer Advocate has agreed not to request or support any rate decreases before Jan. 1, 2012. In addition, earnings exceeding an ROE of 11.75% for 2006 through 2011 will be shared with customers. It remains to be seen whether and to what extent MEHC can replicate this with PacifiCorp, but the speed with which MEHC was able to receive regulatory approval suggests that stakeholders and regulators are supportive of the ownership change. This support may stem from the fact that Berkshire Hathaway has a reputation for holding on to its investments, and the potential for management stability within the company likely provides a degree of comfort to regulators and customers.

Are these competencies why Standard & Poor's affirmed PacifiCorp's CCR at the 'A-' level?
Standard & Poor's does view MEHC ownership as having a potentially stabilizing effect on PacifiCorp's financial performance. However, the affirmation of PacifiCorp's 'A-' CCR was principally based on the benefits PacifiCorp is afforded from the consolidated credit strength of MEHC, whose CCR was raised three notches to 'A-' on March 6 (see "Research Update: MidAmerican Upgraded To 'A-', PacifiCorp Ratings Affirmed; All Ratings Off Watch," RatingsDirect, March 6, 2005).

What is the implication of PacifiCorp's "ring-fencing" for its credit rating?
As a condition of approving the sale, the Oregon Public Utilities Commission (OPUC) required PacifiCorp to be ring-fenced from MEHC. As part of this, MEHC has committed to refrain from dividending cash flows from the utility to MEHC unless it maintains a common equity ratio of 48.25% through 2008, decreasing annually to 44% by 2012.

The structural insulation or "ring-fencing" of an operating company is typically done to protect the credit quality of the operating company from a weaker holding company. When an entity is ring-fenced, Standard & Poor's may rate the operating company up to three notches above the CCR of the parent if its standalone credit metrics warrant the elevation. MEHC has ring fenced MEC, Kern River, Northern Natural, and CE Electric U.K.; some of these companies have historically been rated higher than MEHC.

In PacifiCorp's case, MEHC has set up a special purpose entity, PPW Holdings, LLC that will directly own PacifiCorp. The intent of this structure is to ensure that PacifiCorp is bankruptcy remote from MEHC. Because PacifiCorp's stand-alone credit quality does not warrant a rating above MEHC's, PacifiCorp's rating reflects MEHC's consolidated CCR, as is appropriate under the consolidated rating methodology. If the utility's financial performance improves significantly, it could potentially support a ratings improvement, due to the ring fencing. In addition, it will be somewhat protected from credit deterioration below its own stand-alone credit quality should MEHC's credit quality on a consolidated basis fall to a level below that of PacifiCorp's. In this manner, PacifiCorp's bondholders are somewhat protected from a deterioration due to the failure of another business venture.

What are some of the challenges the new owners of PacifiCorp will face?
Improvement in PacifiCorp's financial performance and business risk is expected to be incremental. From a bondholder perspective, PacifiCorp faces sometimes-difficult regulatory environments in each of the states it serves. For example, in Oregon, PacifiCorp's second most important market, the senate overwhelmingly passed legislation last year, Senate Bill (SB) 408, which requires that utilities refund to their customers income taxes collected in retail rates that are not paid by the parent. SB 408 could provide a permanent clawback mechanism to reduce rate requests, as the OPUC did in September 2005 when it cut PacifiCorp's negotiated settlement by $26 million. (The case is being reheard, and final rules are not expected until this summer.) Utah is considering similar legislation.

As shown in Table 2, since 2002, PacifiCorp has initiated nearly annual rate cases in all states. The company nearly always reaches settlements, which have historically awarded it 25% to 50% less than filed requests. Regulatory support will continue to be tested, especially in the next few years. In February and March 2006, the company filed large requests in its two most important markets, Oregon and Utah. In Oregon, the utility has asked for $112 million, a 13.2% increase in retail rates, based on test year ending Dec. 2007. In Utah, PacifiCorp filed for a $197 million increase, or about 17%, based on a test year ending Sept. 30, 2007. The Utah rate case comes on the heels of a 4.4% increase approved a year ago. While Utah has been more supportive of PacifiCorp in past cases, most of the utility's growth is in this region, implying the importance of this case. While both rate requests are sizable, on the other hand, PacifiCorp's retail rates are very competitive, suggesting some room for compromise.

Table 2 PacifiCorp Rate Cases By State

	Utah	Oregon	Wyoming	Washington	Idaho	California
2006						
Date	3/8/2006	Filed 2/23/2006	2/23/06 (oral ruling)	Filed 5/2005	To be determined (TBD)	Filed 11/20/2005
% rate inc.	17.00	13.2 request	6.90	14.9 request	TBD	15.6 request
$ increase	$197 mil. request	$112 mil. request	$25 mil./$40.2 mil.***	$32.6 mil. request	TBD	$11.0 mil. request
Auth ROE (%)	11.4 request	11.5 request	Not specified	11.125 request	TBD	11.8 request
2005						
Date	3/1/2005	10/4/2005	9/15/2004	N/A	8/9/2005	N/A
% rate inc.	4.40	3.20	2.68	N/A	4.80	N/A
$ increase	$51 mil./$96 mil.¶¶	$25.9 mil./$52.5 mil.*	$9.3 mil.	N/A	$5.8 mil./$15.1 mil.	N/A
Auth ROE (%)	10.5	10.00	Not specified	N/A	Not specified	N/A
2004						
Date	4/1/2004	N/A	3/18/2004	11/2/2004	N/A	N/A
% rate inc.	6.90	N/A	7.19	7.50	N/A	N/A
$ increase	$65 mil./$125 mil.	N/A	$22.9 mil./$34.4 mil.§§	$15 mil./$25.7 mil.	N/A	N/A
Auth ROE (%)	10.70	N/A	10.75	Not specified	N/A	N/A
2003						
Date	N/A	9/19/2003	4/1/2003	N/A	N/A	11/1/03
% rate inc.	N/A	Base 1.1; net 0.8	2.79	N/A	N/A	13.60
$ increase	N/A	$8.5 mil./$18 mil.¶	$8.7 mil./$20 mil.¶¶¶	N/A	N/A	$7.6 mil.
Auth ROE (%)	N/A	10.50	10.75	N/A	N/A	Not specified
2002--None						
2001						
Date	11/2/2001 & 2/9/2001	10/19/2001	10/4/2001	N/A	N/A	N/A
% rate inc.	5.1 perm., 9 temp	Base 8.60; net .60	3.40	N/A	N/A	N/A
$ increase	$40.2 mil.& $70 mil./$142 mil.	$64.4 mil./$103 mil.§	$8.9 mil.	N/A	N/A	N/A
Auth ROE (%)	11.00	10.75	Not specified	N/A	N/A	N/A
2000						

Date	5/25/2000	10/5/2000	6/21/2000	8/16/2000	N/A	N/A
% rate inc.	2.5	1.8	4.9	7 (over 2001-03)	N/A	N/A
$ increase	$17 mil.	$13.6 mil./$21.7 mil.**	$10.6 mil./$40.6 mil.	$13.1 mil./$25.8 mil.	N/A	N/A
Auth ROE		10.75	11.25	Not specified	N/A	N/A
5-Year % inc.	18.8	6.4	20.7	14.5	4.8	13.6

*PacifiCorp reached settlment for $52.5 mil., but amount awarded reduced by about $26 mil. under application of SB408. PacifiCorp is appealing this reduction. ROE reduced to 10% from 10.5%, set in 2003. ¶Majority of reduction related to net power costs and return on equity. §PacifiCorp sought 11.75% ROE, awarded a 10.75% ROE. Of $39 mil. disallowed, $20 mil. related operating costs ($7 mil. pension) and $19 mil. re: rates of return. **Original request for $62 mil. but lowered to $21.7 mil., difference between $21.7 mil. request and $13.6 mil. received reflects agreement to exclude $8.1 mil. in power cost charges. ¶¶Of the $45 mil. difference, between request and actual award, $20 mil. associated with rate of return issues. §§Of the $11.5 mil. difference, about $5 mil. due to rate of return, the other pension, payroll and misc. ***Of the $16 mil. difference, all attributable to PacifiCorp's agreement to not seek this amount in net power increase but instead to have an adjuster. ¶¶¶Does not address $91 mil. in deferred power costs later rejected. $11 mil. difference mostly disallowed power contracts.

About 70% of PacifiCorp's energy requirements come from owned coal, 21% from purchases, 5% from hydro, and 4% from natural gas. As a result, another important issue for PacifiCorp is whether it will be permitted to establish fuel and purchased power adjusters. Wyoming, which disallowed $91 million of PacifiCorp's deferred power costs incurred during the energy crisis, was paradoxically the first state to approve an adjuster. Adjuster requests are pending in nearly all other states, and for Utah and Oregon will likely be considered as part of the general rate cases filed. However, the prospects for adoption in these states are uncertain.

One certain challenge to MEHC will be whether it will be able to achieve the benefits of its diversified portfolio in the face of the inevitable logistical and coordination challenges presented by managing 10 separate regulatory commissions (11, if MEHC's FERC-regulated pipelines are considered). In addition, the financial challenges at PacifiCorp are greater than MEHC faced with MEC, which was only slightly under-earning at the time MEHC acquired it. In contrast, PacifiCorp's under-earning is almost structural in character.

While these challenges are significant, at the same time Scottish Power has made progress in achieving a number of regulatory goals that should significantly benefit MEHC. These accomplishments include: Current retail rates, while still lagging, are nearer to actual costs, due largely to PacifiCorp's relentless filing and settlement of cases in recent years; the adoption of forward test years in four states (Oregon, Utah, Wyoming and California) should avoid the potential for future rates to be based on a stale test year; the company's anticipated rulings for fuel and purchased power adjusters in five jurisdictions may provide significant protection from volatile commodity costs; the conclusion of a multi-state agreement for the allocation of costs in four states (pending in Washington and California) should avoid interstate battles over the proper attribution of costs to each service area; and, lastly, the passage of recent legislation in Utah that pre-approves power plants or purchases greater than 100 MW provides protection from future regulatory disallowances, which is critical because much of PacifiCorp's growth is occurring in this state.

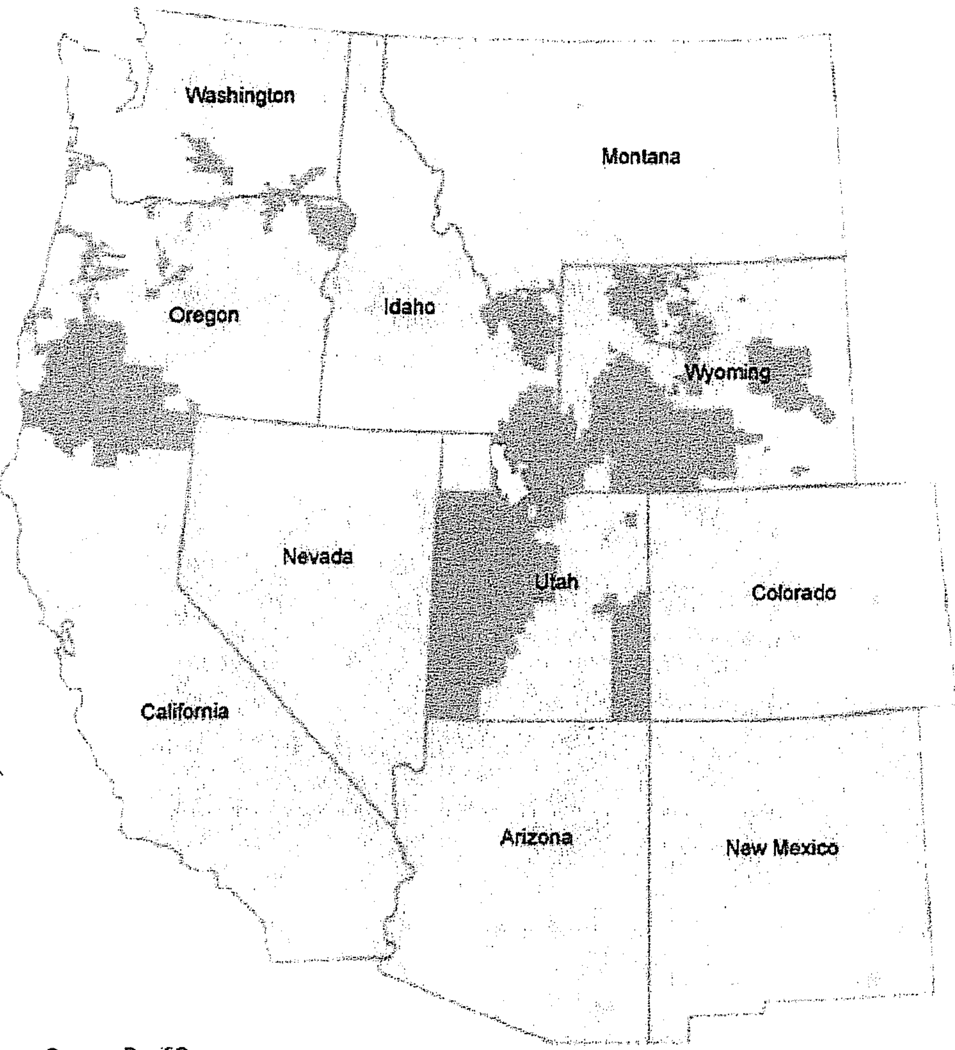
What steps does Standard & Poor's expect MEHC to take to maintain PacifiCorp's credit quality?

Standard & Poor's expects that MEHC will deleverage PacifiCorp through the reinvestment of cash flow into its extensive capital expenditure program. MEHC has represented that it views a properly capitalized utility as having roughly a 50-50 equity-to-debt structure, and it has achieved this at MEC. The dividend restrictions in place as a part of regulatory approval should also provide incentives to deleverage PacifiCorp.

PacifiCorp's rating could fall to a level commensurate with its standalone credit quality if MEHC's rating is lowered. This could result from MEHC's financial performance being weaker than forecast, or if Standard & Poor's view of parent support from Berkshire Hathaway changes. MEHC's rating has limited upside, as improving financial metrics and a successful integration of PacifiCorp have been assumed.

Importantly, Berkshire Hathaway has indicated that it may purchase other utilities. MEHC's consolidated business risk profile score reflects Standard & Poor's expectation that MEHC's future acquisitions will be in the regulated utility segment and not in unregulated or commodity-exposed businesses. If acquisitions were to result in a change in consolidated credit quality, this could affect PacifiCorp's rating.

PacifiCorp Service Area



Source: PacifiCorp.

STANDARD &POOR'S	RATINGSDIRECT

Return to Regular Format

Research:

PacifiCorp

Publication date: 22-Sep-2004
Credit Analyst: Anne Selting, San Francisco (1) 415-371-5009

Corporate Credit Rating	
	A-/Stable/A-2
Outstanding Rating(s)	
PacifiCorp	
Sr unsecd debt	
Local currency	BBB+
Sr secd debt	
Local currency	A-
CP	
Local currency	A-2
Sub debt	
Local currency	BBB+
Pfd stk	
Local currency	BBB
Scottish Power PLC	
Corporate Credit Rating	A-/Stable/A-2
Sr unsecd debt	
Foreign currency	BBB+
Pfd stk	
Foreign currency	BBB
Scottish Power U.K. PLC	
Corporate Credit Rating	A-/Stable/A-2
Sr unsecd debt	A-
CP	
Foreign currency	A-2
PacifiCorp Holdings Inc.	
Corporate Credit Rating	A-/Stable/--
Scottish Power Energy Management Ltd.	
Corporate Credit Rating	A-/Stable/A-2
Scottish Power Energy Retail Ltd.	
Corporate Credit Rating	A-/Stable/A-2
Scottish Power Generation Ltd.	
Corporate Credit Rating	A-/Stable/A-2
Scottish Power Investments Ltd.	
Corporate Credit Rating	A-/Stable/A-2
SP Distribution Ltd.	
Corporate Credit Rating	A-/Stable/A-2
SP Manweb PLC	

Corporate Credit Rating	A-/Stable/A-2
SP Transmission Ltd.	
Corporate Credit Rating	A-/Stable/A-2
PacifiCorp Capital I	
Corporate Credit Rating	A-/Stable/--
Pfd stk	
Local currency	BBB
PacifiCorp Delaware LP	
Corporate Credit Rating	A-/Stable/--
Pfd stk	
Local currency	NR
PacifiCorp Group Holdings Co.	
Corporate Credit Rating	BBB/Stable/NR

Corporate Credit Rating History	
Sept. 29, 1994	A/A-1
Nov. 9, 2001	A-/A-2

Major Rating Factors

Strengths:

- An improving regulatory environment, as evidenced by the roughly $100 million in retail electric rate increases that were granted in five of the six states that PacifiCorp serves, enabling the utility to strengthen its financial performance;
- A strengthened supply portfolio that should ensure that PacifiCorp's owned capacity and wholesale purchases, along with its hedging and balancing activities, are adequate to meet expected load obligations;
- Resolution over recovery of costs associated with the 2001-2002 energy crisis that will allow the utility to collect more than $300 million in deferred power purchases, the majority of which has been collected;
- Electric rates that compare favorably to alternative regional suppliers, coupled with the absence of retail competition in all states but Oregon, where participation in retail choice is still very limited; and
- Market diversity, as reflected in PacifiCorp's sales to retail electric customers in six western states.

Weaknesses:

- The lack of a power or fuel cost adjustment mechanism in any of the states that PacifiCorp serves, coupled with reliance on a fairly high level of wholesale purchases to meet loads, which creates the potential for authorized rates to be insufficient to meet actual costs;
- Sizable capital expenditures that are driven largely by infrastructure needs along the Wasatch Front in Utah and which will peak at more than $1 billion in fiscal 2006 and will require additional debt financing;
- PacifiCorp Holding Inc.'s (PHI) strategic focus on increasing the non-regulated operations of PacifiCorp's' affiliate, PPM Energy Inc., which consist of renewable and gas-fired generation as well as gas storage operations, coupled with nonregulated activities at two of PHI's other subsidiaries; and
- The expiration of hydro licenses for much of the utility's 1,100 MW of capacity, creating uncertainties over remediation costs and potentially resulting in reductions in the operational capacity of the dams to address environmental concerns.

Rationale

PacifiCorp is a wholly owned subsidiary of PHI, which in turn is a nonoperating, direct, wholly owned subsidiary of U.K. utility holding company ScottishPower plc. ScottishPower acquired PacifiCorp in

In fiscal 2004, about 22% of PacifiCorp's energy requirements were purchased, and of this quantity, about 8 percent are long-term purchases (of which more than half are under fixed price arrangements) and 14 percent are shorter term. This level of wholesale purchases is consistent with 2003, when purchases were about 23%, and forecast purchases are expected to remain at this level through 2006. Many of its contracts are for hydro capacity with various Pacific Northwest public utility districts that generally have investment grade credit. The utility's purchases are not concentrated with any one supplier and consist of investor-owned utilities, public utility districts, and qualifying facilities. Although the longest agreement extends into 2029, the majority of the utility's purchases are of intermediate length. PacifiCorp's two largest purchases are with Hermiston Generation Co. and TransAlta Energy Marketing (BBB-/Stable/--). PacifiCorp has an undivided 50% interest in Hermiston, which is a 474 MW plant in Oregon, and it procures all power and purchases the balance of the plant's output under a long-term contract.

In 2002, PacifiCorp entered into a 15-year operating lease for a 215 MW generation plant with West Valley Leasing Co. LLC, which is a subsidiary of PPM. PacifiCorp has an option to terminate the lease in 2005 and 2008. While the recent addition of gas-fired generation as well as plans to build new gas assets in Utah should reduce utility peak purchases, a significant disruption in the wholesale markets continues to pose a threat to the utility, particularly when considered against its lack of power cost adjustment mechanisms.

Production costs.

PacifiCorp's average variable and fixed cost of production, weighted by generation, was a very low $15.66/MWh in 2003, reflecting the utility's efficient coal plants and low cost hydro. The company has been targeting improved operating performance as a priority, which in fiscal 2004 resulted in a 1.7% increase in megawatt hours of production of PacifiCorp's thermal plant. This enhanced performance offset reduced output from the utility's hydro facilities.

Given the prominence of coal in the utility's portfolio, an important credit concern is the stability of PacifiCorp's coal supply and the price of this supply. Under long-term arrangements, the utility owns or leases from private parties and the Bureau of Land Management (BLM) much of the coal reserves that fuel its plants. For example, two-thirds of the supply for the company's largest coal plant, Jim Bridger (2,120 MW), is provided by an adjacent mine operated by Bridger Coal Co., a joint venture between Pacific Minerals Inc., a subsidiary of PacifiCorp, and Idaho Power Co., which has a one-third ownership in the Jim Bridger coal plant. The coal company pays royalties to the BLM and to private parties. The balance of coal for the Jim Bridger plant is supplied by the Black Butte mine under a contract that has both escalated and fixed pricing and expires in 2009. Through ownership or lease, as of March 31, 2004, the utility had an estimated 225 million tons of recoverable coal reserves under lease or ownership arrangements, against an annual use of about 25 million tons. PacifiCorp also relies on spot and contract purchases for some of its requirements.

PacifiCorp does have some exposure to rising coal prices given that several of its largest contracts have reopeners in the next three to five years. Specifically, in addition to the Jim Bridger contract, the utility's coal supply agreements for about 80% of the coal supply at Hunter has a reopener in 2007, and PacifiCorp's 700 MW Naughton plant in Wyoming has a reopener in January 2006.

New generation.

PacifiCorp is required to establish an integrated resource plan that solicits competitive bids to serve future loads. PacifiCorp issued a request for proposals (RFP) in June 2003 that sought bids for the construction of gas-fired resources to meet growing Utah loads. Through the process, PacifiCorp has elected to self-build Currant Creek, a new 525 MW gas-fired combustion turbine plant south of Salt Lake City. Currant Creek will be brought online in two phases, with two 140 MW (280 MW total) simple cycle turbines coming online in summer 2005 and the balance consisting of two heat recovery steam generators and steam generation turbines, which will be added in the spring 2006. Construction began in March.

In May, PacifiCorp also announced that it has entered into an asset purchase and sale agreement with Summit Vineyard LLC of Denver to develop and construct a 534 MW gas-fired combined-cycle combustion turbine near Salt Lake City. The Lakeside plant is expected to come online in the summer of 2007. Construction will led by Siemens Westinghouse Power Corp.

With these two new resources, PacifiCorp expects to be slightly long through 2007, but will need at least 600 MW beginning in 2008. The company plans to issue an additional RFP in 2004 calling for bids to procure resources that can be delivered to PacifiCorp's service territories in Utah, southwest Wyoming, or southeast Idaho. In addition, in February 2004, the utility issued a RFP for 1,000 MW of economic renewable resources, in response to OPUC's directive that the utility build a greener portfolio. The utility has not yet published results of this RFP.

Risk management.
As with other electric utilities, PacifiCorp is exposed to natural gas and power price and volume volatility. In fiscal 2004, for example, 54% of the operating expenses of $2.1 billion (excluding depreciation and amortization) were for power and fuel costs. The company strives to maintain a balanced or slightly long position to protect against unexpected events resulting from weather, forced outages, transmission constraints, and low hydro years. Through financial and physical contracting, the utility's exposure to commodity price fluctuations is relatively modest. Its five-day, 99% value at risk (VaR) for natural gas and electric purchases and sales is expected to be $16 million through 2006. Its VaR for the fiscal year ended March 31, 2004, was $18 million, but has been as high as $23 million over the year and as low as $8 million.

#1

The company engages in only limited pure trading and marketing activities, with most sales related to the buying and selling of power to optimize its assets. PacifiCorp's risk management policies do not allow speculative trading or position taking, but do allow for some arbitrage trading, for example back-to-back buy/sell trades. In addition, most of PacifiCorp's wholesale sales are system firm, allowing the utility to cut deliveries without penalty if there is a force majeure event on its system. The company also maintains a general policy of being balanced or long during periods of high demand.

PacifiCorp's current policies are to fully hedge its gas purchases to achieve a balanced or slightly long position two years out. As a result, the gas supply required to meet the utility's average expected daily burn rate of 102,000 MMBTUs is fully hedged through 2006 via the use of fixed price, forward, physical purchases. With the addition of Currant Creek and Lakeside, which together will add 1,059 MW of new gas generation by 2007, gas purchase requirements are expected to be at least 195,000 MMBTUs per day. The company is re-evaluating its hedging strategies to incorporate physical and financial hedging mechanisms. To manage hydro risk, the utility has entered into a five-year stream flow budget hedge with Aquila Merchant Services that makes a payment to the utility in dry years and requires a payment from the utility in wet years. The agreement expires September 2006.

Competition

The competitiveness of PacifiCorp's retail rates, coupled with an absence of retail competition in the five of six states it operates in, is a clear credit attribute. Owing to its resource mix of efficient coal resources and significant low-cost hydro assets, as well as company efforts to cut costs, PacifiCorp's rates are low in all six states and, unusually, in nearly all the customer classes it serves. In all states, the utility's 2003 residential, commercial, and industrial rates were all highly competitive. Also notable is the absence of retail competition in all states but Oregon, where choice was introduced in the spring of 2002, but interest has been nominal.

While retail rates are very favorable, the combination of bringing new generation online, investing significantly in infrastructure in growing areas of service territory, rising fuel and purchased power costs, clean air investments, hydro relicensing costs, as well as rising medical insurance and pension costs are expected to put significant pressure on retail rates in the coming decade.

Financial

In line with Standard & Poor's consolidated ratings methodology, ScottishPower U.K.'s financial position is analyzed on a consolidated basis, including PacifiCorp and all other group businesses.

ScottishPower's financial policy is moderately aggressive. An onerous capital investment program geared at numerous growth projects is expected to markedly increase the company's debt balance. The sale of Southern Water Services enabled the company to reduce its debt, which had increased partly as a result of the merger with PacifiCorp. Adjusted average total debt to total capital at the consolidated ScottishPower group is poor at about 61%, but is projected to decline to about 56% in fiscal 2005. Adjusted average total debt to total capital at PacifiCorp is about 58%.

Profitability and cash flow.

About 85% of operating profits and cash flow derive from ScottishPower's regulated businesses. Profit margins and cash flow protection measures for the group have been restored as PacifiCorp has been able to recover much of its deferred power costs incurred during the Western energy crisis as well as increase its regulated rate base. In addition, improvement of the utility's power supply and demand imbalance that persisted through much of the California energy crises has occurred. Moreover, margins from energy supply operations in the U.K. in recent years have increased. Ongoing support is provided by a diverse and predictable regulated revenue stream, the substantial rebalancing of PacifiCorp's demand with generation following commissioning of new generating capacity, and the ongoing delivery of significant cost savings at both operating utilities. The "Transition Plan" at PacifiCorp has delivered significant cumulative cost savings of more than $250 million, with this figure still expected to rise.

More than one-half of the company's sizable capital expenditure plan (projected at about £1.1 billion in fiscals 2004 and 2005) will be targeted at growth projects in electricity generation and networks and gas storage. Although projected capital expenditure is geared primarily toward low-to-moderate risk regulated projects, net cash flow coverage is expected to be low, and so Standard & Poor's expects ScottishPower to limit its investment so as to maintain FFO interest coverage of about 4.0x. Pretax interest coverage will remain modest at between 3.2x and 3.5x for the consolidated group, despite rising interest charges reflecting its increasing debt profile.

Capital structure and financial flexibility.

ScottishPower's onerous capital investment program is expected to markedly increase the company's debt balance. Net debt was reduced to about £4.3 billion at March 31, 2004, resulting in a balanced capital structure. However, debt will rise in line with the company's capital expenditure program. More than 80% of outstanding debt (about 70% is fixed rate) has a maturity of five years or more, which is conservative and reflects the long-term assets of the underlying business. In addition, the company's debt maturity profile has improved with the repayment of short-term borrowings. ScottishPower's recent $700 million convertible bond issue was structured in perpetual subordinated form and therefore receives a degree of equity credit.

ScottishPower maintains considerable short-term flexibility under its liquidity lines, and seeks to reduce refinancing risk by issuing longer-term debt that matches the life of its assets. Standard & Poor's expects ScottishPower to maintain significant cash balances until March 2005, when the use of committed backup facilities will be restored. The company has adequate cash balances and sufficient capacity under its $1 billion in revolving credit facility. Adequate borrowing capacity at the operating companies exists because ScottishPower U.K. maintains a $2 billion euro-commercial paper program and PacifiCorp has a $1.5 billion domestic commercial paper program and an $800 million revolving credit facility.

PHI's balance sheet reflects at March 31, 2004, intercompany acquisition related debt consisting of binding payment obligations equivalent in substance to $2.375 billion of medium term notes bearing interest of 6.75% and maturing between 2012 and 2017. Further, since Standard & Poor's looks at financials on a consolidated basis for ScottishPower, this transaction has no impact on the financial ratios. In the event that dividends from the operating subsidiary do not allow PHI to make interest or principal payments to ScottishPower, these obligations would be restructured by SP. However, to date, all obligations have been met on a timely basis and forecasts indicate that this will continue to be the case.

Table 3 Scottish Power Group Inc./PacifiCorp					
(£ in millions)					
	2004	2003	2002	2001	2000

Blue Chip Economic Indicators

Top Analysts' Forecasts Of The U.S. Economic Outlook For The Year Ahead

Vol. 31, No. 3
March 10, 2006

Long-Range Consensus U.S. Economic Projections

II. For comparison, this table includes some of the long-range consensus projections found on the preceding page, plus the latest long-range projections from the Bush Administration[1] and the Congressional Budget Office (CBO)[2].

		YEAR					Five-Year Averages	
ECONOMIC VARIABLE		**2008**	**2009**	**2010**	**2011**	**2012**	**2008-12**	**2013-17**
		Percent Change, Full Year-Over-Prior Year						
1. Real GDP (chained, 2000 dollars)	**CONSENSUS**	**3.1**	**3.1**	**3.1**	**2.9**	**3.0**	**3.1**	**3.0**
	Bush Admin.[1,3]	3.3	3.1	3.1	3.1	na	3.2	na
	CBO[2,3]	3.4	3.3	3.0	2.8	2.7	3.0	2.6
2. GDP Chained Price Index	**CONSENSUS**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Bush Admin.[1,3]	2.1	2.1	2.1	2.1	na	2.1	na
	CBO[2,3]	1.8	1.8	1.8	1.8	1.8	1.8	1.8
3. Nominal GDP (current dollars)	**CONSENSUS**	**5.3**	**5.3**	**5.2**	**5.1**	**5.2**	**5.2**	**5.2**
	Bush Admin.[1,3]	5.5	5.3	5.3	5.3	na	5.4	na
	CBO[2,3]	5.3	5.2	4.9	4.6	4.5	4.9	4.4
4. Consumer Price Index (for all urban consumers)	**CONSENSUS**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**	**2.4**
	Bush Admin.[1,3]	2.4	2.4	2.4	2.5	na	2.4	na
	CBO[2,3]	2.2	2.2	2.2	2.2	2.2	2.2	2.2
		Annual Average						
5. Treasury Bills, 3-Month (percent per annum)	**CONSENSUS**	**4.7**	**4.7**	**4.7**	**4.5**	**4.6**	**4.6**	**4.6**
	Bush Admin.[1,3]	4.3	4.3	4.3	4.3	na	4.3	na
	CBO[2,3]	4.4	4.4	4.4	4.4	4.4	4.4	4.4
6. Treasury Notes, 10-Year (yield per annum)	**CONSENSUS**	**5.4**	**5.5**	**5.5**	**5.4**	**5.5**	**5.5**	**5.5**
	Bush Admin.[1,3]	5.5	5.6	5.6	5.6	na	5.6	na
	CBO[2,3]	5.2	5.2	5.2	5.2	5.2	5.2	5.2
7. Unemployment Rate (% of civilian labor force)	**CONSENSUS**	**4.8**	**4.8**	**4.9**	**4.9**	**5.0**	**4.9**	**4.9**
	Bush Admin.[1,3]	5.0	5.0	5.0	5.0	na	5.0	na
	CBO[2,3]	5.1	5.2	5.2	5.2	5.2	5.2	5.2

III. In this table, we compare the results of our most recent survey with those of our survey in October 2005[4].

		YEAR					Five-Year Averages	
ECONOMIC VARIABLE		**2008**	**2009**	**2010**	**2011**	**2012**	**2008-12**	**2013-17**
		Percent Change, Full Year-Over-Prior Year						
1. Real GDP (chained, 2000 dollars)	**March Consensus**	**3.1**	**3.1**	**3.1**	**2.9**	**3.0**	**3.1**	**3.0**
	October Consensus	3.2	3.1	3.3	3.2	na	na	na
2. GDP Chained Price Index	**March Consensus**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	October Consensus	2.3	2.2	2.3	2.2	na	na	na
3. Nominal GDP (current dollars)	**March Consensus**	**5.3**	**5.3**	**5.2**	**5.1**	**5.2**	**5.2**	**5.2**
	October Consensus	5.5	5.4	5.5	5.4	na	na	na
4. Consumer Price Index (for all urban consumers)	**March Consensus**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**	**2.4**
	October Consensus	2.5	2.5	2.4	2.5	na	na	na
		Annual Average						
5. Treasury Bills, 3-Month (percent per annum)	**March Consensus**	**4.7**	**4.7**	**4.7**	**4.5**	**4.6**	**4.6**	**4.6**
	October Consensus	4.4	4.3	4.4	4.4	na	na	na
6. Treasury Notes, 10-Year (yield per annum)	**March Consensus**	**5.4**	**5.5**	**5.5**	**5.4**	**5.5**	**5.5**	**5.5**
	October Consensus	5.3	5.3	5.4	5.4	na	na	na
7. Unemployment Rate (% of civilian labor force)	**March Consensus**	**4.8**	**4.8**	**4.9**	**4.9**	**5.0**	**4.9**	**4.9**
	October Consensus	4.9	4.9	5.0	4.9	na	na	na

[1]*Budget of the United States Government, Fiscal Year 2007*, Office of Management and Budget, February 2006. [2]*The Budget and Economic Outlook: Fiscal Years 2007-2016;* Congressional Budget Office, February 2006. [3]The Bush Administration's forecast only extends through 2011, so averages for the 2008-2012 period are based on the forecast for the four-year period 2008-2012. CBO's forecast only extends through 2016, so averages for the 2013-2017 period are based on the forecast for the four-year period 2013-2016. [4]*Blue Chip Economic Indicators*, October 10, 2005.

CUB-ICNU/403
Gorman/33

Blue Chip Financial Forecasts

Top Analysts' Forecasts of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them

Vol. 25, No. 6
June 1, 2006

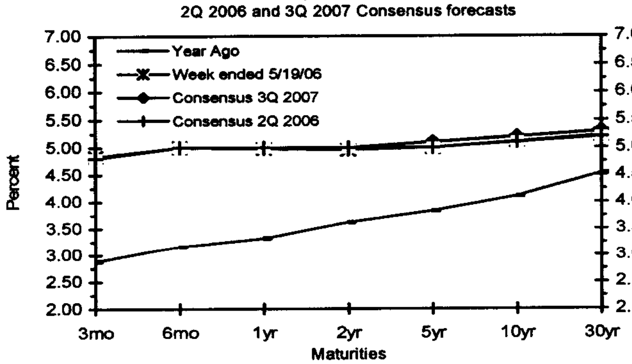
Consensus Forecasts Of U.S. Interest Rates And Key Assumptions[1]

	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Q	2Q	3Q	4Q	1Q	2Q	3Q
Interest Rates	May 19	May 12	May 5	Apr. 28	Apr.	Mar.	Feb.	1Q 2006	2006	2006	2006	2007	2007	2007
Federal Funds Rate	5.00	4.84	4.83	4.74	4.79	4.59	4.49	4.46	4.9	5.1	5.2	5.2	5.0	4.9
Prime Rate	8.00	7.79	7.75	7.75	7.75	7.53	7.50	7.43	7.9	8.1	8.2	8.2	8.1	7.9
LIBOR, 3-mo.	5.21	5.19	5.16	5.12	5.07	4.92	4.76	4.75	5.1	5.3	5.4	5.3	5.2	5.1
Commercial Paper, 1-mo.	4.96	4.94	4.91	4.87	4.80	4.61	4.47	4.48	4.9	5.2	5.3	5.2	5.1	5.0
Treasury bill, 3-mo.	4.83	4.86	4.82	4.78	4.72	4.63	4.54	4.50	4.8	5.0	5.1	5.0	4.9	4.8
Treasury bill, 6-mo.	5.00	5.02	4.99	4.94	4.90	4.79	4.69	4.65	5.0	5.1	5.2	5.2	5.1	5.0
Treasury bill, 1 yr.	4.98	5.01	4.98	4.94	4.90	4.77	4.68	4.63	5.0	5.2	5.2	5.2	5.1	5.0
Treasury note, 2 yr.	4.96	4.99	4.94	4.92	4.89	4.73	4.67	4.60	5.0	5.1	5.2	5.1	5.1	5.0
Treasury note, 5 yr.	5.00	5.03	5.00	4.95	4.90	4.72	4.57	4.55	5.0	5.2	5.2	5.2	5.1	5.1
Treasury note, 10 yr.	5.11	5.14	5.14	5.07	4.99	4.72	4.57	4.57	5.1	5.2	5.3	5.3	5.2	5.2
Treasury note, 30 yr.	5.22	5.22	5.22	5.15	5.06	4.73	4.54	4.64	5.2	5.3	5.4	5.4	5.4	5.3
Corporate Aaa bond	5.96	5.97	5.99	5.93	5.84	5.53	5.35	5.39	6.0	6.2	6.3	6.3	6.3	6.2
Corporate Baa bond	6.76	6.74	6.75	6.73	6.68	6.41	6.27	6.31	6.9	7.1	7.2	7.2	7.2	7.1
State & Local bonds	4.58	4.63	4.63	4.59	4.58	4.44	4.41	4.41	4.8	5.0	5.0	5.1	5.1	5.0
Home mortgage rate	6.60	6.58	6.59	6.58	6.51	6.32	6.25	6.24	6.6	6.8	6.8	6.8	6.8	6.8
	History								Consensus Forecasts-Quarterly Avg.					
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q
Key Assumptions	2004	2004	2004	2005	2005	2005	2005	2006	2006	2006	2006	2007	2007	2007
Major Currency Index	88.0	86.5	81.9	81.3	83.5	84.7	85.8	84.9	82.4	81.8	81.1	80.4	79.8	79.7
Real GDP	3.5	4.0	3.3	3.8	3.3	4.1	1.7	5.3	3.2	3.0	2.9	2.9	3.0	3.0
GDP Price Index	3.9	1.5	2.7	3.1	2.6	3.3	3.5	3.3	2.8	2.4	2.3	2.4	2.3	2.2
Consumer Price Index	3.9	2.1	3.6	2.3	3.8	5.5	3.3	2.2	3.7	2.5	2.4	2.5	2.4	2.4

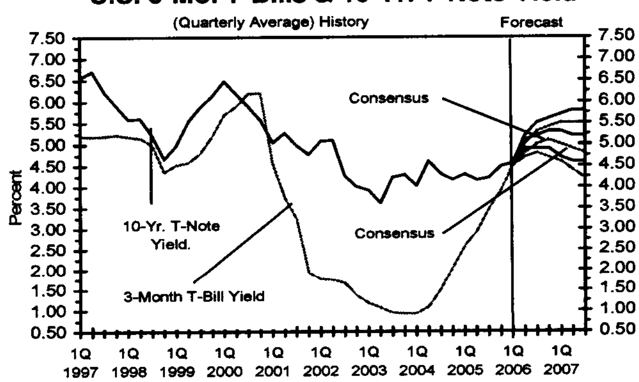
[1]Individual panel members' forecasts are on pages 4 through 9. Historical data for interest rates except LIBOR is from Federal Reserve Release (FRSR) H.15. LIBOR quotes available from *The Wall Street Journal*. Definitions reported here are same as those in FRSR H.15. Treasury yields are reported on a constant maturity basis. Historical data for the U.S. Federal Reserve Board's Major Currency Index is from FRSR H.10 and G.5. Historical data for Real GDP and4.64 GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).

U.S. Treasury Yield Curve

Week ended May 19, 2006 and Year Ago vs. 2Q 2006 and 3Q 2007 Consensus forecasts

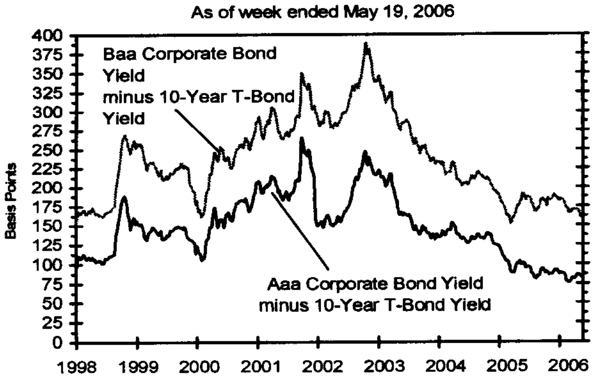


U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield



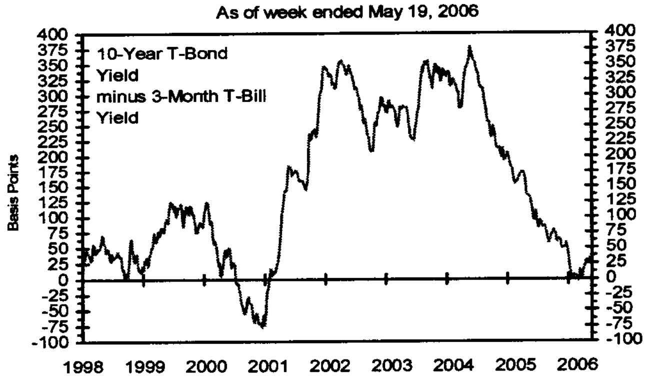
Corporate Bond Spreads

As of week ended May 19, 2006



U.S. Treasury Yield Curve

As of week ended May 19, 2006



BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/404

ACCURACY OF INTEREST RATES FORECASTS

July 12, 2006

PacifiCorp. - Oregon

Accuracy of Interest Rate Forecasts

(Long-Term Treasury Bond Yields - Projected Vs. Actual)

		Publication Data			Actual Yield	Analysis	
Line	Date	Current Yield (1)	Projected Yield (2)	For Quarter (3)	in Projected Quarter (4)	Projected Yield Change (5)	Actual Yield Change (6)
1	**Dec-00**	5.8%	5.8%	1Q, 02	5.6%	0.0%	-0.2%
2	**Mar-01**	5.7%	5.6%	2Q, 02	5.8%	-0.1%	0.1%
3	**Jun-01**	5.4%	5.8%	3Q, 02	5.2%	0.4%	-0.2%
4	**Sep-01**	5.7%	5.9%	4Q, 02	5.1%	0.2%	-0.6%
5	**Dec-01**	5.5%	5.7%	1Q, 03	4.9%	0.2%	-0.6%
6	**Mar-02**	5.3%	5.9%	2Q, 03	4.7%	0.6%	-0.6%
7	**Jun-02**	5.6%	6.2%	3Q, 03	5.2%	0.6%	-0.4%
8	**Sep-02**	5.8%	5.9%	4Q, 03	5.2%	0.1%	-0.6%
9	**Dec-02**	5.2%	5.7%	1Q, 04	4.9%	0.5%	-0.3%
10	**Mar-03**	5.1%	5.7%	2Q, 04	5.4%	0.6%	0.3%
11	**Jun-03**	5.0%	5.4%	3Q, 04	5.1%	0.4%	0.1%
12	**Sep-03**	4.7%	5.8%	4Q, 04	4.9%	1.1%	0.2%
13	**Dec-03**	5.2%	5.9%	1Q, 05	4.8%	0.7%	-0.4%
14	**Mar-04**	5.2%	5.9%	2Q, 05	4.6%	0.7%	-0.6%
15	**Jun-04**	4.9%	6.2%	3Q, 05	4.5%	1.3%	-0.4%
16	**Sep-04**	5.4%	6.0%	4Q, 05	4.8%	0.6%	-0.6%
17	**Dec-04**	5.1%	5.8%	1Q, 06	4.6%	0.7%	-0.4%
18	**Jan-05**	4.9%	5.8%	2Q, 06			
19	**Feb-05**	4.9%	5.8%	2Q, 06			
20	**Mar-05**	4.9%	5.6%	2Q, 06			
21	**Apr-05**	4.7%	5.7%	3Q, 06			
22	**May-05**	4.8%	5.6%	3Q, 06			
23	**Jun-05**	4.8%	5.5%	3Q, 06			
24	**Jul-05**	4.6%	5.3%	4Q, 06			
25	**Aug-05**	4.6%	5.2%	4Q, 06			
26	**Sep-05**	4.6%	5.2%	4Q, 06			
27	**Oct-05**	4.5%	5.2%	1Q, 07			
28	**Nov-05**	4.5%	5.3%	1Q, 07			
29	**Dec-05**	4.5%	5.3%	1Q, 07			
30	**Jan-06**	4.8%	5.3%	2Q, 07			
31	**Feb-06**	4.8%	5.1%	2Q, 07			
32	**Mar-06**	4.8%	5.1%	2Q, 07			
33	**Apr-06**	N/A	5.1%	3Q, 07			
34	**May-06**	4.6%	5.2%	3Q, 07			
35	**Jun-06**	4.6%	5.3%	3Q, 07			

Source:
Blue Chip Financial Forecasts, Various Dates.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/405

COMPARABLE GROUP

July 12, 2006

PacifiCorp. - Oregon

Comparable Group

Line	Electric Utility	Bond Ratings S&P[1] (1)	Bond Ratings Moody's[1] (2)	Business Profile Rating[3] (3)	2005 Common Equity Ratios Value Line[2] (4)	2005 Common Equity Ratios AUS[1] (5)
1	Alliant Energy	A-	A2	6	53%	48%
2	Ameren Corp.	A-	A3	6	53%	52%
3	Consol. Edison	A	A1	3	49%	47%
4	Empire District	A-	Baa1	6	49%	47%
5	Energy East Corp.	BBB+	A3	3	44%	41%
6	SCANA Corp.	A-	A1	4	47%	42%
7	Southern Co.	A+	A2	4	44%	44%
8	Vectren Corp.	A	A3	3	49%	42%
9	Xcel Energy Inc.	A-	A3	5	47%	42%
10	**Average**	**A-**	**A3**	**4**	**48%**	**45%**
11	PacifiCorp	A-	Baa1	5	**49%**[4]	

Sources:
[1] AUS Utility Report; May, 2006.
[2] The Value Line Investment Survey; March 31, May 12, June 6, 2006.
[3] U.S. Utilities and Power Ranking List, March 24, 2006.
[4] Schedule MPG-1.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/406

GROWTH RATE ESTIMATES

July 12, 2006

PacifiCorp. - Oregon

Growth Rate Estimates

Line	Electric Utility	Zacks Estimated Growth %[1]	Number of Estimates[1]	Reuters Estimated Growth %[2]	Number of Estimates[2]	Thomson Estimated Growth %[3]	Number of Estimates[3]	AVG of Growth Rates
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Alliant Energy	4.00%	2	4.00%	3	4.50%	2	4.17%
2	Ameren Corp.	6.00%	5	5.20%	5	5.00%	4	5.40%
3	Consol. Edison	3.86%	7	3.67%	6	3.51%	7	3.68%
4	Empire District	N/A	N/A	2.00%	2	3.00%	3	2.50%
5	Energy East Corp.	4.50%	2	4.33%	3	4.33%	3	4.39%
6	SCANA Corp.	4.67%	6	4.50%	4	4.50%	6	4.56%
7	Southern Co.	4.78%	9	4.70%	10	4.75%	8	4.74%
8	Vectren Corp.	5.00%	3	3.50%	2	4.98%	4	4.49%
9	Xcel Energy Inc.	4.17%	6	4.29%	7	5.00%	6	4.49%
10	**Average**	**4.62%**	**5**	**4.02%**	**5**	**4.40%**	**5**	**4.27%**

Sources:
[1] www.zacksadvisor.com, Detailed Research on June 6, 2006.
[2] www.investor.reuters.com, Earnings Estimates on June 6, 2006.
[3] http://ec.thomsonfn.com, Earnings Estimates on June 6, 2006.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/407

CONSTANT GROWTH DCF MODEL

July 12, 2006

PacifiCorp. - Oregon

Constant Growth DCF Model

Line	Electric Utility	13-Week AVG Stock Price[1] (1)	AVG (%) Growth (2)	Annual Dividend[2] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	Alliant Energy	$ 32.69	4.17%	$ 1.15	3.67%	7.84%
2	Ameren Corp.	$ 49.83	5.40%	$ 2.54	5.37%	10.77%
3	Consol. Edison	$ 43.34	3.68%	$ 2.30	5.50%	9.18%
4	Empire District	$ 22.24	2.50%	$ 1.28	5.90%	8.40%
5	Energy East Corp.	$ 24.04	4.39%	$ 1.16	5.04%	9.42%
6	SCANA Corp.	$ 39.11	4.56%	$ 1.68	4.49%	9.05%
7	Southern Co.	$ 32.30	4.74%	$ 1.55	5.03%	9.78%
8	Vectren Corp.	$ 26.38	4.49%	$ 1.22	4.83%	9.33%
9	Xcel Energy Inc.	$ 18.41	4.49%	$ 0.86	4.88%	9.37%
10	**Average**	**$ 32.04**	**4.27%**	**$ 1.53**	**4.97%**	**9.2%**

Sources:
[1] http://moneycentral.msn.com, downloaded on June 6, 2006.
[2] The Value Line Investment Survey; March 31, May 12, June 6, 2006.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/408

GDP GROWTH RATES

July 12, 2006

PacifiCorp. - Oregon

GDP Growth Rates

Line	Electric Group	Dividend Growth			Inflation (CPI)*			Nominal GDP*	
		Past 5 Years[1] (1)	Past 10 Years[1] (2)	3-5 Years Projection[1] (3)	Past 5 Years[2] (4)	Past 10 Years[2] (5)	3-5 Years Projection[2] (6)	Past 5 Years[1] (7)	Past 10 Years[1] (8)
1	Alliant Energy	-7.5%	-3.5%	1.5%					
2	Ameren Corp.	N/A	1.0%	N/A					
3	Consol. Edison	1.0%	1.5%	1.0%					
4	Empire District	N/A	N/A	N/A					
5	Energy East Corp.	5.0%	1.5%	4.5%					
6	SCANA Corp.	2.0%	0.5%	6.0%					
7	Southern Co.	1.0%	2.0%	4.5%					
8	Vectren Corp.	3.0%	N/A	3.5%					
9	Xcel Energy Inc.	-11.0%	-5.0%	5.5%					
10	**Average**	**-0.9%**	**-0.3%**	**3.8%**	**2.7%**	**2.5%**	**2.2%**	**5.2%**	**5.3%**

Sources:
[1] The Value Line Investment Survey; December 30, 2005, February 10, March 3, 2006.
[2] Value Line Investment Survey, July 7, 2000 and March 17, 2006.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

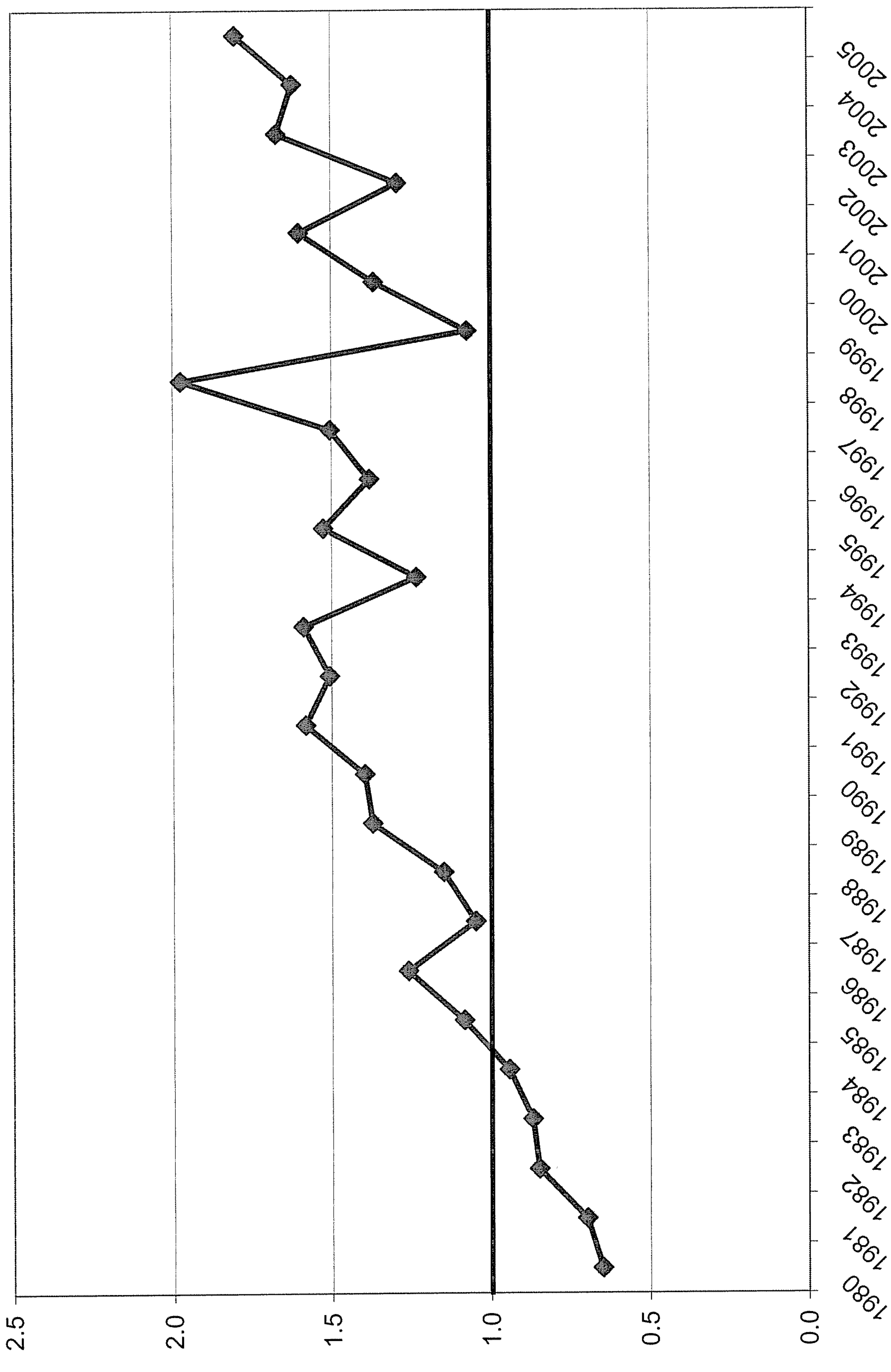
In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

CUB-ICNU/409

ELECTRIC COMMON STOCK MARKET/BOOK RATIO

July 12, 2006

PacifiCorp. - Oregon
Electric Common Stock Market/Book Ratio



Sources:
2002-2005: C.A. Turner Utility Reports.
1980 - 2000: Mergent Public Utility Manual, 2003; at a15, and a17.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/410

EQUITY RISK PREMIUM – TREASURY BOND

July 12, 2006

PacifiCorp. - Oregon

Equity Risk Premium - Treasury Bond

Line	Date	Treasury Bond Yield[1] (1)	Authorized Electric Returns[2] (2)	Indicated Risk Premium (3)
1	1986	7.78%	13.93%	6.15%
2	1987	8.59%	12.99%	4.40%
3	1988	8.96%	12.79%	3.83%
4	1989	8.45%	12.97%	4.52%
5	1990	8.61%	12.70%	4.09%
6	1991	8.14%	12.55%	4.41%
7	1992	7.67%	12.09%	4.42%
8	1993	6.59%	11.41%	4.82%
9	1994	7.37%	11.34%	3.97%
10	1995	6.88%	11.55%	4.67%
11	1996	6.71%	11.39%	4.68%
12	1997	6.61%	11.40%	4.79%
13	1998	5.58%	11.66%	6.08%
14	1999	5.87%	10.77%	4.90%
15	2000	5.94%	11.43%	5.49%
16	2001	5.49%	11.09%	5.60%
17	2002	5.42%	11.16%	5.74%
18	2003	5.02%	10.97%	5.95%
19	2004	5.05%	10.73%	5.68%
20	2005	4.65%	10.54%	5.89%
21	**Average**	**6.77%**	**11.77%**	**5.00%**

Sources:

[1] Economic Report of the President, January, 2001 and the St. Louis Federal Reserve Bank Website.

[2] Regulatory Research Associates, Inc., Regulatory Focus, Jan.90-Dec.05.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/411

EQUITY RISK PREMIUM – UTILITY BOND

July 12, 2006

PacifiCorp. - Oregon

Equity Risk Premium - Utility Bond

Line	Date	Average "A" Rating Utility Bond Yield[1] (1)	Authorized Electric Returns[2] (2)	Indicated Risk Premium (3)
1	1986	9.58%	13.93%	4.35%
2	1987	10.10%	12.99%	2.89%
3	1988	10.49%	12.79%	2.30%
4	1989	9.77%	12.97%	3.20%
5	1990	9.86%	12.70%	2.84%
6	1991	9.36%	12.55%	3.19%
7	1992	8.69%	12.09%	3.40%
8	1993	7.59%	11.41%	3.82%
9	1994	8.31%	11.34%	3.03%
10	1995	7.89%	11.55%	3.66%
11	1996	7.75%	11.39%	3.64%
12	1997	7.60%	11.40%	3.80%
13	1998	7.04%	11.66%	4.62%
14	1999	7.62%	10.77%	3.15%
15	2000	8.24%	11.43%	3.19%
16	2001	7.78%	11.09%	3.31%
17	2002	7.36%	11.16%	3.80%
18	2003	6.57%	10.97%	4.40%
19	2004	6.01%	10.73%	4.72%
20	2005	5.66%	10.54%	4.88%
21	**Average**	**8.16%**	**11.77%**	**3.61%**

Sources:
[1] Mergent Public Utility Manual, Mergent weekly News Reports, 2003.
[2] Regulatory Research Associates, Inc., Regulatory Focus, Jan.90-Dec.05.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/412

SERIES "A" AND "Baa" UTILITY BOND YIELDS

July 12, 2006

PacifiCorp. - Oregon

Series "A" and "Baa" Utility Bond Yields

Line	Date	"A" Rating Utility Bond Yield (1)	"Baa" Rating Utility Bond Yield (2)
1	06/02/06	6.32%	6.50%
2	05/26/06	6.38%	6.57%
3	05/19/06	6.35%	6.53%
4	05/12/06	6.51%	6.67%
5	05/05/06	6.40%	6.57%
6	04/28/06	6.37%	6.61%
7	04/21/06	6.32%	6.56%
8	04/14/06	6.34%	6.60%
9	04/07/06	6.20%	6.45%
10	03/31/06	6.14%	6.40%
11	03/24/06	5.95%	6.22%
12	03/17/06	5.96%	6.25%
13	03/10/06	5.99%	6.28%
14	**Average**	**6.25%**	**6.48%**

Source:
www.moodys.com, Bond Yields and Key Indicators.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/413

COMPARABLE GROUP BETA

July 12, 2006

PacifiCorp. - Oregon

Comparable Group Beta

Line	Electric Utility	Value Line Beta (1)
1	Alliant Energy	0.85
2	Ameren Corp.	0.75
3	Consol. Edison	0.70
4	Empire District	0.75
5	Energy East Corp.	0.90
6	SCANA Corp.	0.80
7	Southern Co.	0.65
8	Vectren Corp.	0.80
9	Xcel Energy Inc.	0.85
10	**Average**	**0.78**

Sources:
The Value Line Investment Survey; March 31, May 12, June 6, 2006.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/414

CAPM RETURN ESTIMATE

July 12, 2006

PacifiCorp. - Oregon

CAPM Return Estimate

Line	Description	Historical Premium (1)
1	Risk Free Rate[1]	5.3%
2	Risk Premium[2]	6.5%
3	Beta[3]	0.78
4	CAPM	10.4%
		Prospective Premium (1)
5	Risk Free Rate[1]	5.3%
6	Risk Premium[2]	6.4%
7	Beta[3]	0.78
8	CAPM	10.3%
9	**CAPM Average**	**10.4%**

Sources:
[1] Blue Chip Financial Forcasts; June 1, 2006, at pp.2.
[2] SBBI; 2006 at pp. 31 & 120.
[3] The Value Line Investment Survey; March 31, May 12, June 6, 2006.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/415

PACIFICORP RESPONSE TO ICNU DATA REQUEST NO. 7.63

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

July 12, 2006

UE-179/PacifiCorp
May 18, 2006
ICNU 7th Set Data Request 7.63

ICNU Data Request 7.63

7.1 Concerning PacifiCorp's off-balance sheet debt equivalence created through capital leases and purchased power debt equivalence, please provide the following:

a. Identify each PacifiCorp financial commitment for purchased power obligations, capital leases, and other that are included in Standard & Poor's formula for establishing PacifiCorp's off-balance sheet debt equivalence.

b. Identify the term of the financial obligation, fixed annual payment of the financial obligation, total annual payment of the commitment, the amount of the total commitment that is considered by S&P in its determination of PacifiCorp's off-balance sheet debt equivalent.

c. Identify the risk factor used by S&P to establish each financial commitment's debt equivalent.

d. Provide the discount rate used to present value the annual fixed obligation.

e. Provide a an electronic spreadsheet with all formulae intact showing the development, on a line item basis, for each financial obligation, PacifiCorp's total off-balance sheet debt equivalent, separately identifying each contract considered in the development of the total off-balance sheet debt.

f. Identify all assumptions made by PacifiCorp in determining is total off-balance sheet debt equivalent, and state whether or not it has any confirmation from S&P of the accuracy or reasonableness of PacifiCorp's assumptions.

Response to ICNU Data Request 7.63

a. PacifiCorp provided information on the aggregate contract obligations to Standard & Poor's by following categories:

(1) Mix of Energy & Capacity, (2) Capacity, (3) Energy, (4) Transmission, and (5) Mid-C Hydro.

Confidential Attachment ICNU 7.63 a on the enclosed CD shows the aggregate annual payment streams associated with PacifiCorp's long term purchased power obligations provided to Standard & Poor's.

Capital Leases were not included as those are already reported separately in the Company's financial statements.

b. Please refer to Response to ICNU Data Request 7.63 a. Standard & Poor's used the following weightings for purchased power obligations by category follows:

(1) Mix of Energy & Capacity 50%

UE-179/PacifiCorp
May 18, 2006
ICNU 7th Set Data Request 7.63

(2) Capacity	100%
(3) Energy	Excluded
(4) Hydro	100%

c. Standard & Poor's has published a 50% risk factor to apply for calculating PacifiCorp's indebtedness from the present value of the weighted stream of purchased power obligations.

d. Standard & Poor's has published a 10% discount rate as appropriate to present value the weighted stream of purchased power contract obligations.

e. PacifiCorp objects to this request as irrelevant and unduly burdensome. The information in Responses to ICNU 7.a through 7.d presents the information in an aggregated form and is what was provided to Standard & Poor's.

f. PacifiCorp calculated the off-balance sheet indebtedness from its purchased power contract obligations and other assumptions referenced in Responses to ICNU 7.a through 7.d. The resulting indebtedness is in line with the $537 million reported by Standard & Poor's in its March 21, 2006 report. Please refer to Attachment ICNU 7.63 f on the enclosed CD, page 1

OREGON

2006 GENERAL RATE CASE

UE-179

PACIFICORP

ICNU 7th SET DATA REQUEST

CONFIDENTIAL ATTACHMENT ICNU 7.63 a

CONFIDENTIAL (LEVEL YELLOW)

ON THE ENCLOSED CD

CONFIDENTIAL

INFORMATION

OMITTED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/416

S&P CREDIT RATING FINANCIAL METRIC CALCULATIONS

July 12, 2006

PacifiCorp. - Oregon

S&P Credit Rating Financial Ratios at ROE of 9.8%

Line	Description	Ratio at 9.8% Equity Return (1)	S&P "A" Rating (BP: 5) Benchmark* (2)	S&P "BBB" Rating (BP: 5) Benchmark* (3)	Reference (4)
1	Rate Base	$ 2,302,198,746			Exhibit PPL 901, Page 2.2
2	Weighted Common Return	4.57%			Page 2, Line 4, Col. 4.
3	Income to Common	$ 105,198,600			Line1 x Line 2.
4	Depreciation	$ 121,382,321			Exhibit PPL 901, Page 2.2
5	Amortization	$ 18,573,130			Exhibit PPL 901, Page 2.2
6	Deferred Income Tax	$ 5,252,012			Exhibit PPL 901, Page 2.2
7	Funds from Operations (FFO)	$ 250,406,063			Sum of Line 3 though 6.
8	Weighted Interest Rate	3.55%			Page 2, Line 1 , 2 and 0.5*Line 3, Col. 4.
9	Interest Expense	$ 81,815,016			Line 1 x Line 8.
10	FFO Plus Interest	$ 332,221,080			Line 7 + Line 9.
11	FFO Interest Coverage	**4.1x**	**4.5x - 3.8x**	3.8x - 2.8x	Line 10 / Line 9.
12	Total Debt Ratio	**53%**	42% - 50%	**50% - 60%**	Page 2, Line 1 , 2 and 0.5*Line 3, Col. 2.
12	FFO to Total Debt	**21%**	30% - 22%	**22% - 15%**	Line 7 / (Line 1 x Line 12).

Source:
* Standard and Poors. New Business Profile Scores Assigned to U.S. Utility and Power Companies; Financial Guidelines Revised; June 2, 2004.

PacifiCorp. - Oregon

Rate of Return at 9.8% ROE

Line	Description	Amount (1)	Weight (2)	Cost (3)	Weighted Cost (4)
1	Long-Term Debt	$ 4,311,258	47.4%	6.37%	3.02%
2	OBS Debt	$ 456,000	5.0%	10.00%	0.50%
3	Preferred Stock	$ 82,713	0.9%	6.54%	0.06%
4	Common Equity	$ 4,237,032	46.6%	**9.80%**	4.57%
5	**Total**	**$ 9,087,003**	**100.0%**		**8.15%**

Source:
Williams Direct, Exhibit PPL 300 at 3.

PacifiCorp. - Oregon

Purchased Power Agreement (PPA)

Line	Calender Year	31-Dec-06 (1)	31-Dec-07 (2)	31-Dec-08 (3)	31-Dec-09 (4)	31-Dec-10 (5)	31-Dec-11 (6)	31-Dec-12 (7)	....	31-Dec-46 (8)	31-Dec-47 (9)
1	Mix Energy & Capacity	21,776,418	21,676,145	20,997,870	20,726,933	20,742,603	20,751,599	20,146,166		-	-
2	Capacity	127,773,822	129,245,288	130,563,078	131,649,649	126,388,468	110,729,468	100,355,299		-	-
3	Energy	615,529,087	253,859,739	173,056,134	173,741,320	79,807,590	71,388,101	12,376,295		-	-
4	Transmission	57,096,091	50,625,652	47,913,738	45,856,678	43,600,320	42,455,568	42,253,357		1,079,898	1,079,898
5	Mid-C Hydro	14,475,177	14,750,205	15,045,209	13,906,813	6,697,615	6,844,962	7,009,241		-	-
6	**Total**	**836,650,595**	**470,157,029**	**387,576,029**	**385,881,393**	**277,236,596**	**252,169,698**	**182,140,358**		**1,079,898**	**1,079,898**
7	Mix Energy & Capacity	10,888,209	10,838,073	10,498,935	10,363,467	10,371,302	10,375,800	10,073,083		-	-
8	Capacity	127,773,822	129,245,288	130,563,078	131,649,649	126,388,468	110,729,468	100,355,299		-	-
9	Mid-C Hydro	14,475,177	14,750,205	15,045,209	13,906,813	6,697,615	6,844,962	7,009,241		-	-
10	**Total**	**153,137,208**	**154,833,566**	**156,107,222**	**155,919,929**	**143,457,385**	**127,950,230**	**117,437,623**		-	-
11	West Valey Lease		5,000,000	2,083,333							
12	NPV 06-47	$1,023,473,768									
13	Risk Factor	50%									
14	**OBS Debt**	**511,736,884**									
15	OBS Interest	51,173,688									
16	NPV 08-47	$913,224,826	Excluding West Valley Lease Adjustment								
17	Risk Factor	50%									
18	**OBS Debt**	**456,612,413**									
19	OBS Interest	45,661,241									

Source:
Exhibit ICNU Set 7, Data Response 7.63 (a).

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/417

ADJUSTED HADAWAY ANALYSES

July 12, 2006

PacifiCorp. - Oregon

Adjusted Hadaway's DCF Results

Line	Description	Traditional DCF Model (1)	LT GDP DCF Model (2)	Two-Stage DCF Model (3)	Average DCF Model (4)
1	Hadaway	9.5%	11.3%	10.8%	**10.5%**
2	Adjusted Hadaway	9.1%	9.9%	9.6%	**9.5%**

Notes:
*GDP growth rate changed to 5.2% from 6.6%.

PacifiCorp. - Oregon

Discounted Cash Flow Analysis
Traditional Constant Growth DCF Model

Line	Electric Utility	Stock Price (P0) (1)	Next Year's Div (D1) (2)	Dividend Yield (3)	2009 DPS (4)	2009 EPS (5)	Retention Rate (B) (6)	2009 BVPS (7)	ROE (R) (8)	BxR Growth (9)	Zacks (10)	Value Line (11)	GDP (12)	Average Growth (13)	ROE (14)
1	Alliant Energy	27.77	1.07	3.85%	1.15	2.25	48.89%	27.55	8.17%	3.99%	3.70%	6.50%	5.20%	4.85%	8.7%
2	Ameren Corp.	52.05	2.54	4.88%	2.54	3.35	24.18%	35.20	9.52%	2.30%	6.00%	2.50%	5.20%	4.00%	8.9%
3	CH Energy	46.51	2.16	4.64%	2.20	3.25	32.31%	34.50	9.42%	3.04%	N/A	4.50%	5.20%	4.25%	8.9%
4	Consolidated Edison	45.90	2.30	5.01%	2.36	3.00	21.33%	32.60	9.20%	1.96%	4.00%	1.50%	5.20%	3.17%	8.2%
5	Empire District	20.86	1.28	6.14%	1.28	1.50	14.67%	16.00	9.38%	1.38%	5.00%	5.00%	5.20%	4.14%	10.3%
6	Energy East Corp.	23.66	1.18	4.99%	1.35	2.00	32.50%	21.00	9.52%	3.10%	4.50%	4.50%	5.20%	4.32%	9.3%
7	MGE Energy	34.83	1.38	3.96%	1.44	2.45	41.22%	18.70	13.10%	5.40%	N/A	6.00%	5.20%	5.53%	9.5%
8	NSTAR	27.81	1.20	4.31%	1.32	2.00	34.00%	17.50	11.43%	3.89%	4.80%	2.50%	5.20%	4.10%	8.4%
9	Progress Energy	43.77	2.44	5.57%	2.50	3.40	26.47%	34.50	9.86%	2.61%	4.20%	N/A	5.20%	4.00%	9.6%
10	SCANA Corp.	40.02	1.66	4.15%	1.90	3.25	41.54%	29.25	11.11%	4.62%	4.80%	4.50%	5.20%	4.78%	8.9%
11	Southern Co.	34.72	1.53	4.41%	1.71	2.50	31.60%	18.15	13.77%	4.35%	4.70%	4.00%	5.20%	4.56%	9.0%
12	Vectren Corp.	27.18	1.23	4.53%	1.35	1.95	30.77%	17.45	11.17%	3.44%	4.60%	4.00%	5.20%	4.31%	8.8%
13	Xcel Energy, Inc.	18.65	0.88	4.72%	1.05	1.50	30.00%	15.00	10.00%	3.00%	4.30%	7.50%	5.20%	5.00%	9.7%
13	**Group Average**	**34.13**	**1.60**	**4.70%**	**1.70**	**2.49**	**31.50%**	**24.42**	**10.43%**	**3.31%**	**4.60%**	**4.42%**	**5.20%**	**4.39%**	**9.1%**
14	**Group Median**			**4.64%**											**8.9%**

Source:
Hadaway Direct, Exhibit PPL 205, Page 2 of 5.

PacifiCorp. - Oregon

Discounted Cash Flow Analysis
Constant Growth DCF Model
Long-Term GDP Growth

Line	Electric Utility	Stock Price (P0) (15)	Next Year's Div (D1) (16)	Dividend Yield (17)	GDP (18)	ROE Col 17+18 (19)
1	Alliant Energy	27.77	1.07	3.85%	5.20%	9.1%
2	Ameren Corp.	52.05	2.54	4.88%	5.20%	10.1%
3	CH Energy	46.51	2.16	4.64%	5.20%	9.8%
4	Consolidated Edison	45.90	2.30	5.01%	5.20%	10.2%
5	Empire District	20.86	1.28	6.14%	5.20%	11.3%
6	Energy East Corp.	23.66	1.18	4.99%	5.20%	10.2%
7	MGE Energy	34.83	1.38	3.96%	5.20%	9.2%
8	NSTAR	27.81	1.20	4.31%	5.20%	9.5%
9	Progress Energy	43.77	2.44	5.57%	5.20%	10.8%
10	SCANA Corp.	40.02	1.66	4.15%	5.20%	9.3%
11	Southern Co.	34.72	1.53	4.41%	5.20%	9.6%
12	Vectren Corp.	27.18	1.23	4.53%	5.20%	9.7%
13	Xcel Energy, Inc.	18.65	0.88	4.72%	5.20%	9.9%
13	**Group Average**	**34.13**	**1.60**	**4.70%**	**5.20%**	**9.9%**
14	**Group Median**			**4.64%**		**9.8%**

Source:
Hadaway Direct, Exhibit PPL 205, Page 3 of 5.

PacifiCorp. - Oregon

Discounted Cash Flow Analysis
Low Near-Term Growth
Two-Stage Growth DCF Model

Line	Electric Utility	Next Year's Div (D_1) (20)	2009 DPS (21)	Annual Change to 2008 (22)	Stock Price (P0) (23)	Year 1 Div (24)	Year 2 Div (25)	Year 3 Div (26)	Year 4 Div (27)	Year 5 Div (28)	Year 5-150 Growth (29)	ROE = IRR (30)
1	Alliant Energy	1.07	1.15	0.03	-27.77	1.07	1.10	1.12	1.15	1.21	5.20%	8.8%
2	Ameren Corp.	2.54	2.54	0.00	-52.05	2.54	2.54	2.54	2.54	2.67	5.20%	9.4%
3	CH Energy	2.16	2.20	0.01	-46.51	2.16	2.17	2.19	2.20	2.31	5.20%	9.3%
4	Consolidated Edison	2.30	2.36	0.02	-45.9	2.30	2.32	2.34	2.36	2.48	5.20%	9.7%
5	Empire District	1.28	1.28	0.00	-20.86	1.28	1.28	1.28	1.28	1.35	5.20%	10.5%
6	Energy East Corp.	1.18	1.35	0.06	-23.66	1.18	1.24	1.29	1.35	1.42	5.20%	10.1%
7	MGE Energy	1.38	1.44	0.02	-34.83	1.38	1.40	1.42	1.44	1.51	5.20%	8.8%
8	NSTAR	1.20	1.32	0.04	-27.81	1.20	1.24	1.28	1.32	1.39	5.20%	9.3%
9	Progress Energy	2.44	2.50	0.02	-43.77	2.44	2.46	2.48	2.50	2.63	5.20%	10.2%
10	SCANA Corp.	1.66	1.90	0.08	-40.02	1.66	1.74	1.82	1.90	2.00	5.20%	9.3%
11	Southern Co.	1.53	1.71	0.06	-34.72	1.53	1.59	1.65	1.71	1.80	5.20%	9.4%
12	Vectren Corp.	1.23	1.35	0.04	-27.18	1.23	1.27	1.31	1.35	1.42	5.20%	9.5%
13	Xcel Energy, Inc.	0.88	1.05	0.06	-18.65	0.88	0.94	0.99	1.05	1.10	5.20%	10.0%
13	**Group Average**	**1.60**	**1.70**	**0.03**	**-34.13**							**9.6%**
14	**Group Median**											**9.4%**

Source:
Hadaway Direct, Exhibit PPL 205, Page 4 of 5.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

CUB-ICNU/418

ANNUAL AVERAGE YIELDS

July 12, 2006

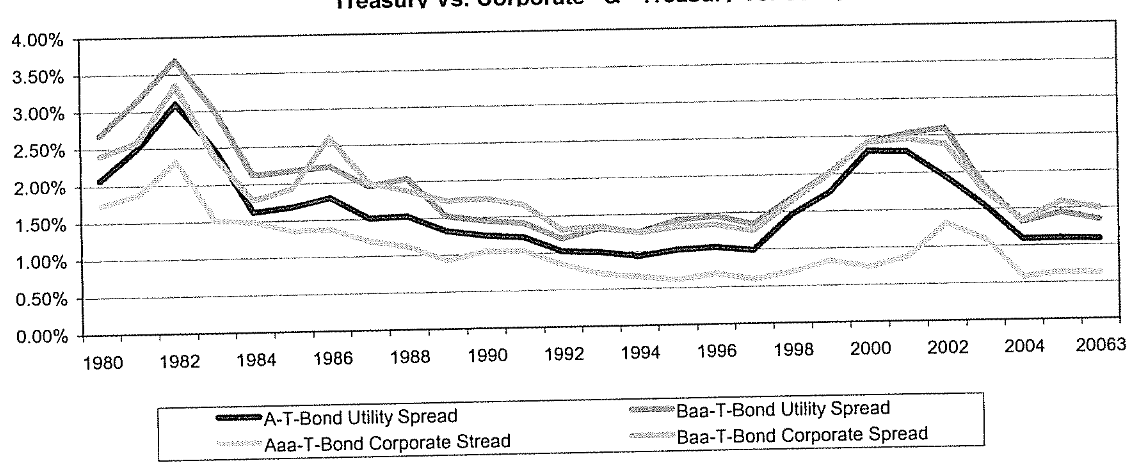
PacifiCorp. - Oregon

Annual Average Yields

			Public Utility Bond Yields				Corporate Bond Yields			
Line	Year	T-Bond Yield[1]	A[2]	Baa[2]	A-T-Bond Spread	Baa-T-Bond Spread	Aaa[1]	Baa[1]	Aaa-T-Bond Spread	Baa-T-Bond Spread
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	1980	11.27%	13.34%	13.95%	2.07%	2.68%	11.94%	13.67%	1.73%	2.40%
2	1981	13.45%	15.95%	16.60%	2.50%	3.15%	14.17%	16.04%	1.87%	2.59%
3	1982	12.76%	15.86%	16.45%	3.10%	3.69%	13.79%	16.11%	2.32%	3.35%
4	1983	11.18%	13.66%	14.20%	2.48%	3.02%	12.04%	13.55%	1.51%	2.37%
5	1984	12.41%	14.03%	14.53%	1.62%	2.12%	12.71%	14.19%	1.48%	1.78%
6	1985	10.79%	12.47%	12.96%	1.68%	2.17%	11.37%	12.72%	1.35%	1.93%
7	1986	7.78%	9.58%	10.00%	1.80%	2.22%	9.02%	10.39%	1.37%	2.61%
8	1987	8.59%	10.10%	10.53%	1.51%	1.94%	9.38%	10.58%	1.20%	1.99%
9	1988	8.96%	10.49%	11.00%	1.53%	2.04%	9.71%	10.83%	1.12%	1.87%
10	1989	8.45%	9.77%	9.97%	1.32%	1.52%	9.26%	10.18%	0.92%	1.73%
11	1990	8.61%	9.86%	10.06%	1.25%	1.45%	9.32%	10.36%	1.04%	1.75%
12	1991	8.14%	9.36%	9.55%	1.22%	1.41%	8.77%	9.80%	1.03%	1.66%
13	1992	7.67%	8.69%	8.86%	1.02%	1.19%	8.14%	8.98%	0.84%	1.31%
14	1993	6.59%	7.59%	7.91%	1.00%	1.32%	7.22%	7.93%	0.71%	1.34%
15	1994	7.37%	8.31%	8.63%	0.94%	1.26%	7.96%	8.62%	0.66%	1.25%
16	1995	6.88%	7.89%	8.29%	1.01%	1.41%	7.59%	8.20%	0.61%	1.32%
17	1996	6.71%	7.75%	8.17%	1.04%	1.46%	7.37%	8.05%	0.68%	1.34%
18	1997	6.61%	7.60%	7.95%	0.99%	1.34%	7.26%	7.86%	0.60%	1.25%
19	1998	5.58%	7.04%	7.26%	1.46%	1.68%	6.53%	7.22%	0.69%	1.64%
20	1999	5.87%	7.62%	7.88%	1.75%	2.01%	7.04%	7.87%	0.83%	2.00%
21	2000	5.94%	8.24%	8.36%	2.30%	2.42%	7.62%	8.36%	0.74%	2.42%
22	2001	5.49%	7.78%	8.02%	2.29%	2.53%	7.08%	7.95%	0.87%	2.46%
23	2002	5.42%	7.36%	8.02%	1.94%	2.60%	6.49%	7.80%	1.31%	2.38%
24	2003	5.02%	6.57%	6.83%	1.55%	1.81%	5.67%	6.77%	1.10%	1.75%
25	2004	5.05%	6.14%	6.37%	1.09%	1.32%	5.63%	6.39%	0.58%	1.34%
26	2005	4.73%	5.83%	6.17%	1.10%	1.44%	5.37%	6.32%	0.64%	1.59%
27	2006[3]	4.97%	6.05%	6.31%	1.08%	1.34%	5.59%	6.47%	0.62%	1.50%

Yield Spreads

Treasury Vs. Corporate & Treasury Vs. Utility



Notes:
[1] St. Louis Federal Reserve Bank.
[2] Mergent Public Utility Manual 2003. Moodys Daily News Reports.
[3] The average yields for the period Jan-May, 2006.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

DIRECT TESTIMONY OF

KATHRYN E. IVERSON

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

July 12, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

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

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

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

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

Q. WHAT SUBJECTS DO YOU ADDRESS IN THIS TESTIMONY?

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

Q. WHAT SPECIFIC AREAS DOES YOUR TESTIMONY COVER?

A. My testimony discusses the application of marginal generation costs that are assigned to capacity and energy. I provide recommended relative base rate increases necessary to move rates closer to cost of service based on revisions to PacifiCorp's marginal cost study.

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

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

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

A. While the Company is seeking an overall increase of 13.2% in base rates, the proposed increase to Schedule 48 customers is 19.1%. PPL/1102, Griffith/1, column 13, line 6. This increase is 1.45 times the system average increase and represents a substantial increase in costs to ICNU's members.

Q. WOULD YOU PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS?

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

- PacifiCorp's marginal cost study does not account for time-differentiation of generation costs; a single generation marginal energy cost is applied to all 8,760 hours of the year equally, and PacifiCorp's study uses an average of twelve monthly peaks for the application of its marginal capacity costs. This gives no recognition to those customers who may be using energy in a more efficient manner, or those customers who are consuming more of their energy during times of lower system cost.
- It is time for PacifiCorp to seriously evaluate its marginal cost procedures and methodologies in order to update its approach to recognize the time-differentiation of generation costs. Without this update, PacifiCorp's marginal cost study will not provide meaningful information on the marginal costs to serve

its various types of customer loads. PacifiCorp's approach is punitive to large industrial customers. My analysis shows that on a more accurate cost of service basis, Schedule 48 customers should receive a below-average percentage increase, and definitely, no more than the average system cost percentage increase.

- My recommended rate spread is based on two changes to the marginal cost study. First, the marginal capacity cost of generation should be based on peak demand rather than an average of twelve monthly peaks. The marginal capacity cost of generation used in PacifiCorp's cost study is the cost of a peaking unit, and thus, this cost should be assessed to all customer classes based on peak demand. Second, the marginal energy cost of generation should reflect seasonal and on-peak/off-peak cost differentials.

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

A. Yes, I have. Mr. Anderberg presents the results of a marginal cost study and the development of unbundled class revenue requirements in PPL/1005. According to the Company's cost study, Schedule 48T secondary rates should be increased by 19.9%, primary rates by 19.0% and transmission rates by 18.1%, for a total base rate increase of 19.1% to Schedule 48T. In contrast, the overall base rate increase for all classes is 13.2%.

Q. DO YOU BELIEVE THE COST STUDY PROVIDES MEANINGFUL MARGINAL GENERATION COST INFORMATION ON THE COST TO SERVE VARIOUS CUSTOMER CLASSES?

A. No. The cost study makes no distinction in the cost to serve customers having vastly different load shapes and usage patterns. Importantly, the application of marginal generation costs is so completely undifferentiated, it offers little if any substantive information on the actual marginal generation cost to serve a customer. Problems exist in both the application of the marginal demand and marginal energy costs of the generation function. I propose two changes in the cost study that better recognize customer usage and load patterns.

Q. PLEASE EXPLAIN HOW YOUR PROPOSALS WOULD IMPACT RATES.

A. Using PacifiCorp's requested revenue requirement and my recommendation for rate allocation and rate spread, the following table compares PacifiCorp's and ICNU's changes in both base rates and net rates for illustrative purposes. Under ICNU's proposal, Schedule 48 would receive a base rate increase of 8.8% and, with inclusion of all proposed riders, a net rate increase of 10.5%. This compares to PacifiCorp's request for a base rate increase of 19.1% and net rate increase of 19.8%. Residential customers would receive a higher net rate increase of 15.3% compared to PacifiCorp's request for 10.8%. Schedules 23, 28, and 41 would receive net increases between 10% and 11%, while Schedule 30 would receive the system average increase.

	Base Rate Changes		Net Rate Changes	
	PacifiCorp	ICNU	PacifiCorp	ICNU
Residential:				
Schedule 4	10.8%	15.4%	10.8%	15.3%
Commercial & Industrial:				
Schedule 23	13.2%	3.3%	19.8%	11.2%
Schedule 28	13.0%	16.9%	9.4%	10.4%
Schedule 30	16.4%	16.7%	12.9%	13.3%
Schedule 48	19.1%	8.8%	19.8%	10.5%
Schedule 41	15.5%	8.4%	19.8%	11.1%
Lighting	19.9%	19.9%	9.3%	9.3%
Total	13.2%	13.2%	13.2%	13.2%

Q. ARE YOU AWARE OF ANY UTILITIES IN THE NORTHWEST WHO PLACE SUCH A HEAVY PERCENTAGE OF THE PROPOSED RATE INCREASE ON INDUSTRIAL CUSTOMERS?

A. No. The utilities I am familiar with often support an equal percentage basis approach. For example, in PacifiCorp's most recent case in Washington (Docket No. UE-050684 before the Washington Utilities and Transportation Commission ("WUTC")), the parties in that case agreed that Schedule 48T would receive a uniform percentage increase. See WUTC v. PacifiCorp, WUTC Docket No. UE-050684, Joint Testimony on Rate Spread and Rate Design at 5 (Nov. 3, 2005). As another example in Washington, the parties intervening in Puget Sound Energy's previous rate case entered into a stipulation on rate spread which spread all non-power cost increases on an equal percentage basis, except for Schedules 25 and 449/459, which received 75% of the average. WUTC v. PSE, WUTC Docket No. UE-040641, Order No. 6 at ¶¶ 247-48 (Feb. 18, 2005). For Puget Sound Energy's pending rate filing, the utility has proposed that high voltage customers receive an average system increase. WUTC v. PSE, WUTC Docket No. UE-060266, Summary Document at 1 (Feb. 15, 2006).

Here in Oregon, Portland General Electric Company ("PGE") is currently seeking a system average increase of 5.8% in Docket No. UE 180, with the net impact to Large Non-Residential customers being 5.4%. Re PGE, OPUC Docket No. UE 180, Pretrial Brief of PGE at Exh. 1 (Mar. 15, 2006). Including the effects of Port Westward on PGE's rates, Large Non-Residential customers would see an increase of 8.8% compared to the system average increase of 8.9%. Consequently, other Northwest industrial customers are seeing increases of approximately the system average.

I. TIME-DIFFERENTIATION OF GENERATION COSTS

Q. ARE MARGINAL COSTS COMMONLY TIME-DIFFERENTIATED?

A. Yes. In order to draw meaningful conclusions about the costs that various types of loads and customer usage place upon a utility system, it is critical to recognize time-differentiation of generation costs. This point is highlighted in the National Association of Regulatory Commissioners' ("NARUC") Electric Utility Cost Allocation Manual in its section on Marginal Production Cost:

> Marginal costs are commonly time-differentiated to reflect variations in the cost of serving additional customer usage during the course of a day or across seasons. Marginal production costs tend to be highest during peak load period when generating units with the highest operating costs are on line and when the potential for generation-related load curtailments or interruptions is greatest. A costing period is a unit of time in which costs are separately identified and causally attributed to different classes of customers. Costing periods are often disaggregated hourly in marginal cost studies, particularly for determining marginal capacity costs which are usually strongly related to hourly system load levels.

Electric Utility Cost Allocation Manual, NARUC at 109 (Jan. 1992).

Q. DOES PACIFICORP PROVIDE ANY RECOGNITION OF TIME-DIFFERENTIATION OF MARGINAL GENERATION COSTS?

A. No. A single generation marginal energy cost is applied to all 8,760 hours of the year equally, thereby ignoring any time-of-day or seasonal differentiation. This gives no recognition to those customers who may be using energy in a more efficient manner, or those customers who are consuming more of their energy during times of lower system cost. PacifiCorp's study also uses an average of twelve monthly peaks for the application of its marginal capacity costs. Consequently, the cost study comes to the erroneous conclusion that load patterns and seasonal usage are irrelevant to the costs of the system.

Furthermore, it sends the signal that it makes no difference how customers use their energy over the course of the year or during different times of day.

Q. ARE ENERGY COSTS TIME-DIFFERENTIATED IN TODAY'S MARKET PLACE?

A. Yes, they certainly are. PacifiCorp provided its December 30, 2005 Official Forward Price Curves in response to OPUC Data Request ("DR") No. 335. These prices are based on actual prices encountered by PacifiCorp for that day, as well as quotes from external brokers. PacifiCorp believes these market quotes are the best available indicator of future prices for the general rate case forecast period.

Those monthly market prices are graphically shown in Exhibit ICNU/302. Page 1 of this exhibit shows the 2007 Mid-C prices for High Load Hours ("HLH") and Low Load Hours ("LLH") (shown as dashed lines), as well as similar information for projection of costs on a flat basis (shown as a solid line). Page 2 shows the 20-year levelized Mid-C prices.[1/] As these graphs clearly show, both the 2007 costs and the levelized 20-year costs exhibit strong seasonality as well as cost differentials for the HLH and LLH.

Q. WHAT DO YOU CONCLUDE FROM THESE GRAPHS AND NARUC'S ADVICE ON TIME-DIFFERENTIATION?

A. It is time for PacifiCorp to seriously evaluate its marginal cost procedures and methodologies in order to update its approach to recognize the time-differentiation of generation costs. Without this update, PacifiCorp's marginal study will not provide meaningful information on the marginal costs to serve its various types of customer

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1/ The 20-year levelized prices are based on 2007-2026 monthly Mid-C prices, using the same economic parameters and methodology for levelization as in PacifiCorp's marginal cost study.

loads. Furthermore, without time-differentiation, the cost study provides little guidance for use in rate spread.

Q. DOES YOUR SUPPORT FOR TIME-DIFFERENTIATION OF MARGINAL GENERATION COSTS LIKEWISE INDICATE YOUR SUPPORT FOR MOVING CUSTOMERS TO TIME OF USE RATES?

A. No, it does not. The purpose of the marginal cost study is to ascertain how best to spread the revenue increase. Time-differentiation of the marginal generation costs should make this study more robust and reflective of the cost consequences of load patterns. Any decision for moving to time of use rates for PacifiCorp's customers is a separate and distinct issue handled as part of the rate design.

We are not proposing any change in current rate design for any of PacifiCorp's customer classes. In PacifiCorp's last general rate case, the Commission approved a stipulation regarding rate design that recommended the adoption of a 1 mil differentiation between on-peak and off-peak rates on an experimental basis. Re PacifiCorp, OPUC Docket No. UE 170, Fourth Partial Stipulation at 5 (July 29, 2005). PacifiCorp has not completed its study evaluating the effectiveness of the program and has not recommended any changes from the rate spread adopted in UE 170. It is appropriate to defer the issue of time of use retail rates until additional information is available.

II. MARGINAL GENERATION COSTS - CAPACITY

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

A. The marginal cost of generation assigned to capacity is defined as the fixed cost of a simple cycle combustion turbine ("SCCT"). The long-run marginal capacity cost of generation used by PacifiCorp in this case is **$74.31 per kW-year.**

Q. TO WHAT CUSTOMER CLASS LOADS DOES PACIFICORP APPLY THIS MARGINAL COST?

A. PacifiCorp applies the marginal capacity cost to "Peak Mw @ Generator" by customer class. These peak amounts are shown on line 5 of tab 2.3 of Exhibit PPL/1007.

Q. WHAT ARE THE "PEAK MW @ GENERATOR" AMOUNTS FOR EACH CUSTOMER CLASS?

A. These class peaks are calculated in the cost study based on "System Load Factors." Class System Load Factors range from roughly 64% to over 100% and are based not on a system peak demand, but on each class's <u>average</u> of twelve monthly coincident peaks ("12 CP").

Q. DOES PACIFICORP PROVIDE AN EXPLANATION OF WHY IT USES AN AVERAGE OF 12 MONTHLY PEAKS IN THE APPLICATION OF ITS MARGINAL GENERATION CAPACITY COST?

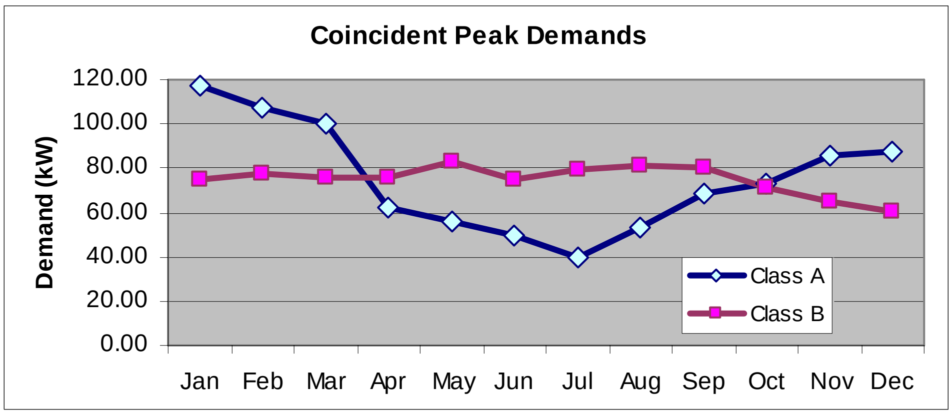
A. There is no discussion provided in the Marginal Cost Description of Procedures. Most likely, the use of the 12 CP method is simply a continuation of how past marginal studies were performed.

Q. DOES THE USE OF THE AVERAGE OF 12 MONTHLY PEAKS INFLUENCE THE RESULTS OF PACIFICORP'S COST STUDY?

A. Yes, very much so. An average of monthly peaks significantly dilutes any signal to customers of the cost implications of meeting Oregon's peak demand. Put simply, PacifiCorp's current cost study makes no distinction between a customer who adds 120 kW to January's coincident peak (and nothing in other months), or 10 kW in each and every month. Under the 12 CP method, the customer which adds a flat stable load to the system is treated no different than a customer requiring an investment <u>12 times the size</u>. This is grossly unfair.

Q. PLEASE EXPLAIN.

A. We can see this result by looking at a simplified example where we compare two classes who both have the same System Load Factor and who use the same amount of energy each year. If we plot their 12 monthly coincident peaks, we see that Class A is much more seasonal in nature, while Class B is relatively flat:



In this example, each class uses 500 MWh energy, each class has a System Load Factor of 76.1% based on their 12 CP, and each class has a 12 CP of 75 kW. However, you will note that Class A has a peak demand roughly three times its lowest demand, while Class B's peaks have little variability.

Q. HOW DOES PACIFICORP'S MARGINAL COST STUDY ASSIGN MARGINAL GENERATION COSTS TO THESE TWO MARKEDLY DIFFERENT CLASSES?

A. PacifiCorp's marginal cost study would result in marginal generation costs that are <u>exactly the same</u> for Class A and Class B. Exhibit ICNU/303, Iverson/1, shows that under PacifiCorp's current methodology, both of these customers would have exactly the same marginal generation cost of $50 per MWH. In other words, despite the fact that Class A has a peak demand of 120 kW – more than 40% higher than Class B – the generation costs for both of these classes supposedly are exactly equal.

Q. WHAT IF THIS SAME EXAMPLE USES A SINGLE PEAK DEMAND FOR THE APPLICATION OF THE MARGINAL CAPACITY COST?

A. Exhibit ICNU/303, Iverson/2, shows that if the System Load Factor is based on the single peak in January, the marginal cost of generation is differentiated between the classes with Class A having a marginal generation cost roughly 5% higher than the system average, and Class B 5% less than the system average. Thus, the fact that Class A puts additional strain on the system peak should be reflected in their marginal cost of service.

Q. DO ANY OF PACIFICORP'S CUSTOMER CLASSES CORRESPOND WITH YOUR EXAMPLE?

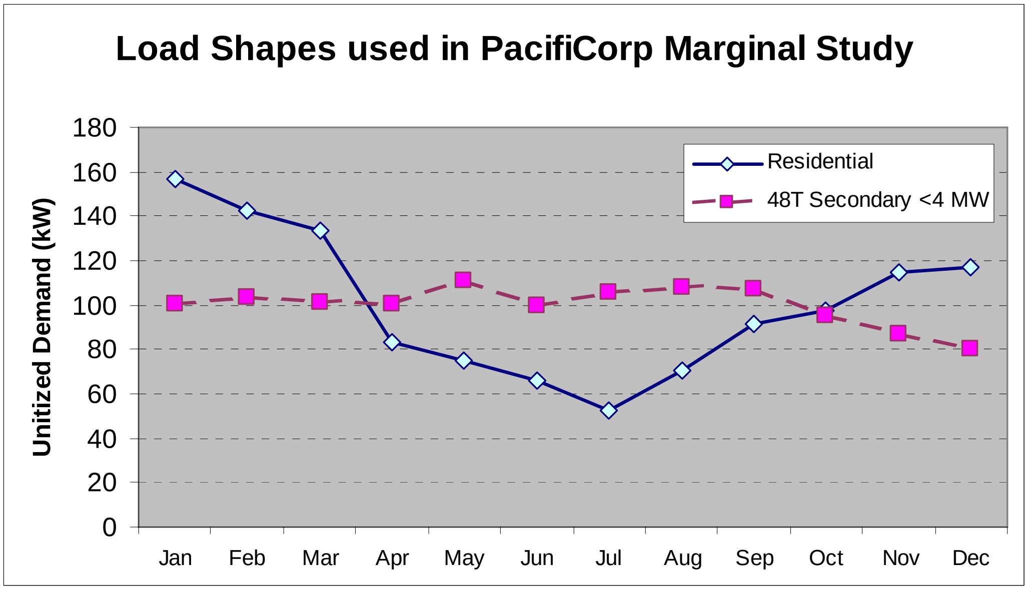
A. Yes. In PacifiCorp's marginal cost study, the Residential class has a System Load Factor of 76.61% and the Large Power Service Schedule 48T secondary customer class with loads less than 4 MW has a System Load Factor of 76.03%. Since both of these classes have similar System Load Factors, the marginal cost study assigns roughly the same per unit marginal cost of generation:

Residential:
(889 MW x $74.31 per kW = $66.032 million)
\+ (5,963,081 MWH x $43.80 per MWH = $261.183 million)
= $327.215 million, or **$54.87 per MWH**

Schedule 48T, 1-4 MW, Secondary:
(126 MW x $74.31 per kW = $9.36 million)
\+ (838,943 MWH x $43.80 per MWH = $36.746 million)
= $46.106 million, or **$54.96 per MWH**

The slight difference in marginal generation cost to serve these two classes is due entirely to the slight difference in System Load Factor.

Now, while their marginal generation costs may be similar, their load patterns are extremely different. Residential usage exhibits strong peaks in the winter and lower peaks in other months, while the secondary 48T class shows flat usage throughout the year. In fact, the load shapes of these two classes were used to develop the example described above (Class A = Residential; Class B = 48T Secondary <4 MW):



Q. DOES IT MAKE SENSE TO APPLY THE $74.31 GENERATION CAPACITY COST TO AN AVERAGE OF TWELVE MONTHLY PEAK DEMANDS?

A. No. The intent of a marginal generation capacity cost is to illustrate the cost of reliably serving a customer. To reliably serve customers, a generation system must be planned and built to meet the maximum demand incurred, with enough additional reserves to meet unexpected outages or variations in load forecast. Generation is not planned simply on an average of load over the course of the year. If it were, customers' peak demands could not be reliably met. Furthermore, the marginal capacity cost of generation represents the cost of a peaking unit. A peaking unit is typically installed and operated to meet increases in loads during peak periods, and, therefore, the peaking unit cost should be applied to peak demands and not average peaks over the course of a year.

Q. WHICH SYSTEM PEAK DO YOU RECOMMEND BE USED IN THE MARGINAL COST STUDY FOR PURPOSES OF APPLYING THE MARGINAL COST OF CAPACITY?

A. I recommend the use of the January system peak. This peak represents the maximum use in the Oregon jurisdiction of the twelve monthly coincident peaks. The use of System Load Factors based on the January system peak results in the following base rate increases in the marginal cost study:

Increase in Base Rates to Meet
Unbundled Revenue Requirement Allocation

	PacifiCorp	ICNU
Residential:		
Schedule 4	10.82%	15.52%
Commercial & Industrial:		
Schedule 23	13.18%	11.00%
Schedule 28	12.99%	10.13%
Schedule 30	16.38%	13.09%
Schedule 48	19.12%	10.59%
Schedule 41	15.43%	0.91%
Total	13.18%	13.18%

III. MARGINAL GENERATION COST - ENERGY

Q. HOW ARE MARGINAL COSTS FOR GENERATION ENERGY DETERMINED IN PACIFICORP'S MARGINAL COST STUDY?

A. The marginal cost of energy is the sum of two components: 1) the variable production cost of the Combined Cycle Combustion Turbine ("CCCT"); and 2) the fixed costs of the CCCT which are in excess of the demand costs of a SCCT. The long-run marginal energy cost of generation used by PacifiCorp in this case is **$43.80 per MWh**, which reflects $42.93 per MWh for the variable CCCT costs, and $0.86 per MWh for the fixed costs in excess of the demand of the SCCT.

Q. DOES PACIFICORP PROVIDE ANY RECOGNITION OF HLH, LLH, OR SEASONALITY IN ITS COST STUDY?

A. No. As I explained earlier, the generation marginal energy cost is applied to all 8,760 hours of the year equally, thereby ignoring any time-of-day or seasonal cost differentiation. This gives no recognition to those customers who are using more of their energy during times of the year or day that are less costly to serve.

Q. DOES THIS MAKE INTUITIVE SENSE IN THE REAL WORLD?

A. No. Costs for energy vary across seasons and by on-peak and off-peak. As shown in Exhibit ICNU/302, both the 2007 costs and the levelized 20-year costs exhibit strong seasonality as well as cost differentials during HLH and LLH.

Q. USING YOUR SIMPLIFIED EXAMPLE IN EXHIBIT ICNU/303, WHAT IS THE MARGINAL COST TO SERVE THE TWO CLASSES USING SEASONALLY DIFFERENTIATED ENERGY COSTS?

A. As one might expect, these two classes consume their energy in different ways, with Class A using the bulk of its energy in the winter, while Class B's energy usage is spread over the course of the year:

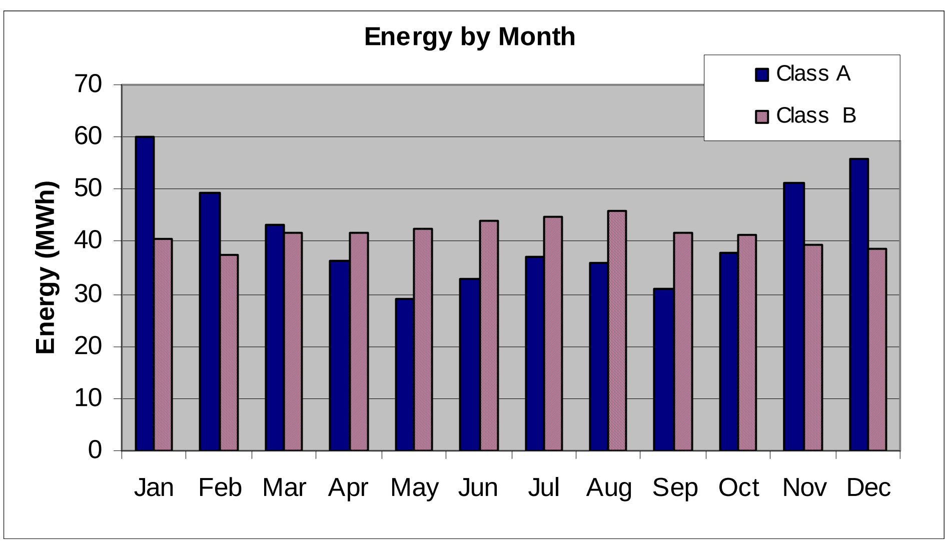


Exhibit ICNU/304, Iverson/1 applies the 2007 monthly energy prices to the monthly loads of Class A and Class B, and Exhibit ICNU/304, Iverson/2 uses the 20-year levelized prices. The examples shown in Exhibit ICNU/304 result in Class A's generation costs being 1.8% higher (using 2007 prices) or 1.2% higher (using 20-year levelized prices) than the system average. Thus, the costs to serve these two different types of loads reflect differing costs by periods.

Q HAVE YOU PREPARED A MARGINAL COST STUDY THAT INCORPORATES TIME-DIFFERENTIATION OF ENERGY COSTS?

A. Yes. Using information from PacifiCorp's response to ICNU DR No. 16, and applying the 20-year levelized high load and low load prices, we find the following percentage increases to the various classes:

Increase in Base Rates to Meet
Unbundled Revenue Requirement Allocation

	PacifiCorp	ICNU
Residential:		
Schedule 4	10.82%	11.31%
Commercial & Industrial:		
Schedule 23	13.18%	13.02%
Schedule 28	12.99%	12.93%
Schedule 30	16.38%	16.12%
Schedule 48	19.12%	17.91%
Schedule 41	15.43%	13.52%
Total	13.18%	13.18%

Q. HAVE YOU RERUN THE MARGINAL STUDY WITH BOTH OF YOUR CHANGES; THAT IS, USING A SINGLE PEAK FOR THE ASSIGNMENT OF CAPACITY AND INCORPORATING THE TIME-DIFFERENTIATION OF ENERGY COSTS?

A. Yes. The following table presents the results of the marginal study with both changes:

Increase in Base Rates to Meet
Unbundled Revenue Requirement Allocation

	PacifiCorp	ICNU
Residential:		
Schedule 4	10.82%	15.98%
Commercial & Industrial:		
Schedule 23	13.18%	10.85%
Schedule 28	12.99%	10.07%
Schedule 30	16.38%	12.84%
Schedule 48	19.12%	9.43%
Schedule 41	15.43%	-0.91%
Total	13.18%	13.18%

IV. RATE SPREAD AND RATE DESIGN

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

A. PacifiCorp allocates the increase in base rates based on the results of its functionalized class cost of service study. Net rates are then developed to include the effect of riders for several adjustment schedules.

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

A. Yes. The Company proposes to implement a rate spread where none of the major rate schedules will see an overall net rate increase greater than approximately 1.5 times the overall average net. I agree with this overall objective, as well as the Company's proposal to set the RMA to zero for both the residential and lighting customers.

However, our rate spread recommendation would start from revenue requirements from a marginal cost study that applies the marginal capacity cost to the single CP and uses time-differentiation of energy costs based on the 20-year levelized Mid-C prices. Furthermore, we propose to set the RMA to zero for Schedules 23 and 47/48. This would leave only three classes continuing to be assessed the RMA: Schedules 28, 30, and 41.

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

A. Yes. For comparison purposes, Exhibit ICNU/305 presents my recommendation using the same dollar amount increase that PacifiCorp has requested. I present this strictly for comparison purposes, and it should not be interpreted as a recommendation that PacifiCorp is entitled to receive the amount of increase that it has requested.

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

A. Both PacifiCorp's and my recommendation show that lighting should receive increases at 70% of the system average. We also both show Schedule 28 receiving a below-average increase, and Schedule 30 at system average. Schedules 23, 41, and 48 would receive increases of 80%-85% of the system average under my recommendation, in comparison to PacifiCorp's recommendation for increases of 150% of system average. The following table compares the relative net rate increases under PacifiCorp's and ICNU's proposals:

Proposed Relative Net Rate Increases

	PacifiCorp	ICNU
Residential:		
Schedule 4	0.82	1.17
Commercial & Industrial:		
Schedule 23	1.51	0.85
Schedule 28	0.71	0.79
Schedule 30	0.98	1.01
Schedule 48	1.51	0.80
Schedule 41	1.51	0.85
Lighting	0.70	0.70
Total	1.00	1.00

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/301

KATHRYN IVERSON QUALIFICATIONS

July 12, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. PLEASE STATE YOUR OCCUPATION.

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

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

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

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

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

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

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

Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

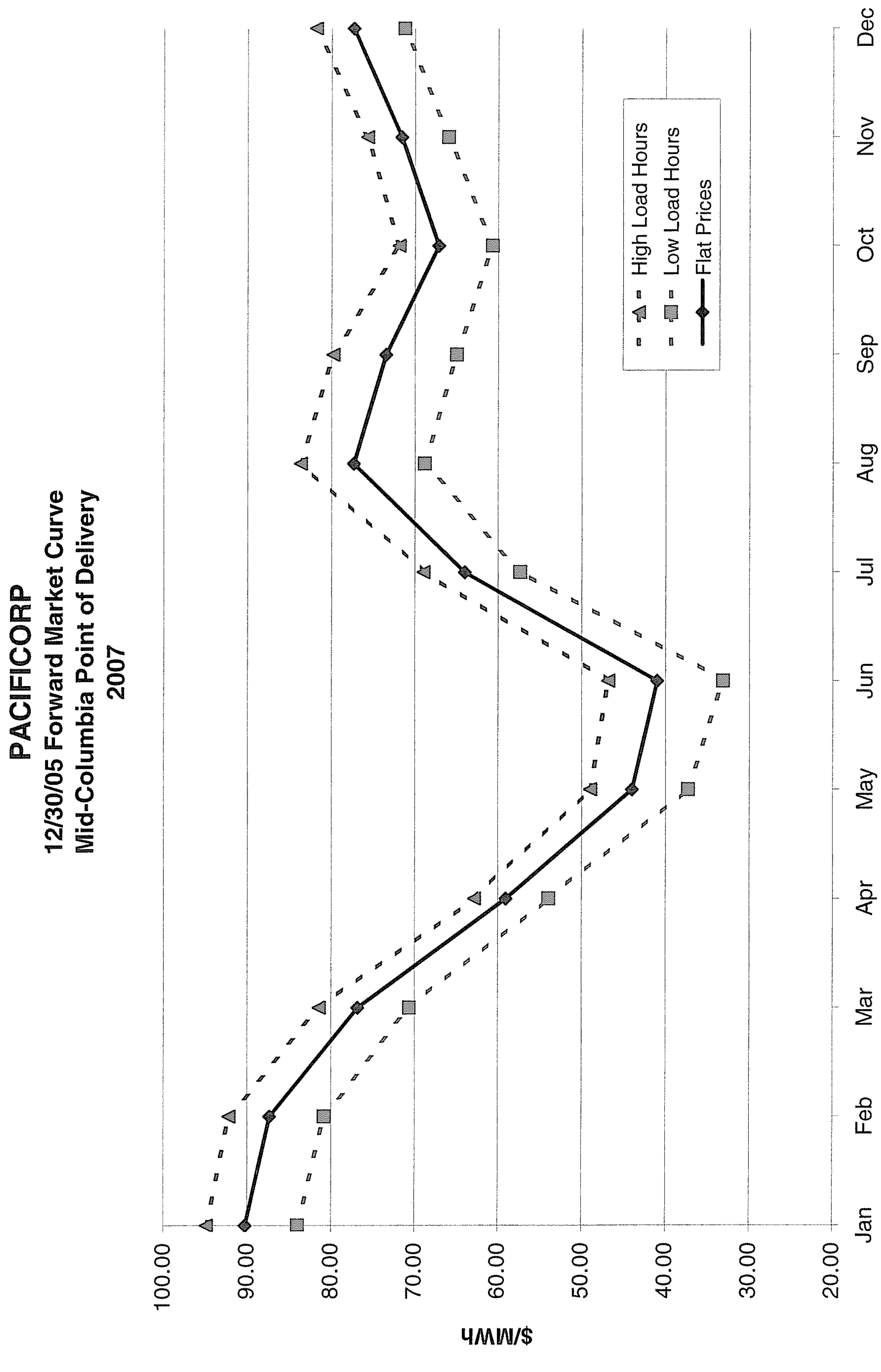
In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues.	)

ICNU/302

12/03/05 FORWARD MARKET CURVE

MID-COLUMBIA POINT OF DELIVERY

July 12, 2006


PACIFICORP
12/30/05 Forward Market Curve
Mid-Columbia Point of Delivery
2007
$/MWh
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
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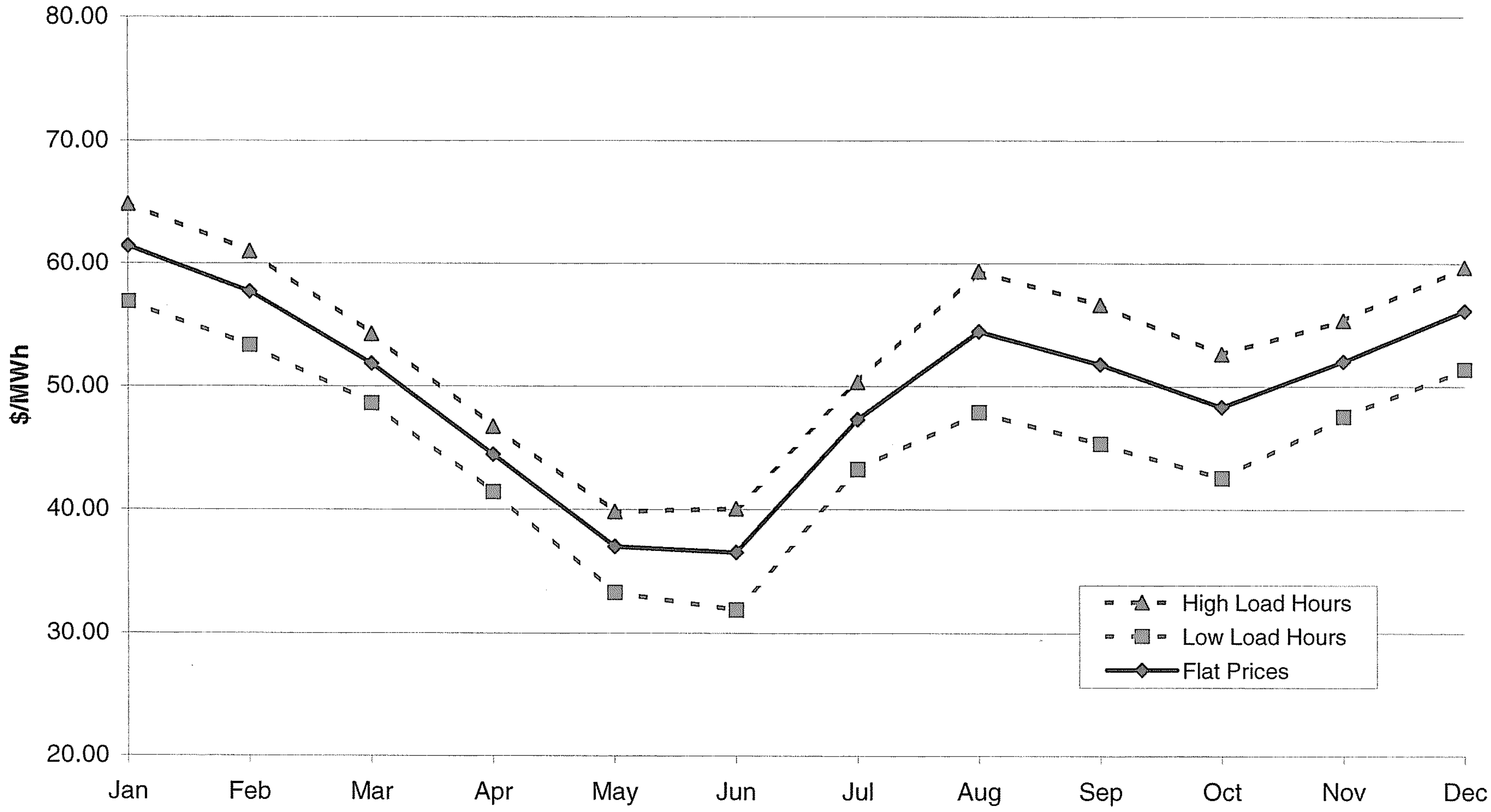
High Load Hours
Low Load Hours
Flat Prices

PACIFICORP
12/30/05 Forward Market Curve
Mid-Columbia Point of Delivery
20-Year Levelized



BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/303

EXAMPLE OF IMPACT OF LOAD PATTERN

ON MARGINAL COST RESULTS

July 12, 2006

PACIFICORP
Example of Impact of Load Pattern on Marginal Cost Results

Ln		Class A (1)	Class B (2)	Total (3)
1	Energy @ Generation (MWH)	500	500	1000
2	System Load Factor (12CP)	76.10%	76.10%	
3	Peak kW @ generator (kW)	75.00	75.00	150.00
4	***PacifiCorp's Marginal Study***			
5	Energy @ Generator	500	500	
6	Unit MC - Generation Energy $/MWH	$43.80	$43.80	
7	Marginal Cost	$21,900	$21,900	$43,800
8	System Demand	75.00	75.00	
9	Unit MC - Generation Capacity $/kW	$74.31	$74.31	
10	Marginal Cost	$5,573	$5,573	$11,147
11	Total Marginal Cost	$27,473	$27,473	$54,947
12	Allocation	50%	50%	100%
13	Revenue Requirement	$25,000	$25,000	$50,000
14	**$ per MWH**	**50.00**	**50.00**	**50.00**

* Assumes a functional revenue requirement of $50,000.

PACIFICORP
Example of Impact of Load Pattern on Marginal Cost Results

Ln		Class A (1)	Class B (2)	Total (3)
1	Energy @ Generation (MWH)	500	500	1000
2	System Load Factor (1CP)	48.64%	75.81%	
3	Peak kW @ generator (kW)	117.35	75.29	
4	***Using Peak Demand***			
5	Energy @ Generator	500	500	
6	Unit MC - Generation Energy $/MWH	$43.80	$43.80	
7	Marginal Cost	$21,900	$21,900	$43,800
8	System Demand	117.35	75.29	
9	Unit MC - Generation Capacity $/kW	$74.31	$74.31	
10	Marginal Cost	$8,720	$5,595	$14,315
11	Total Marginal Cost	$30,620	$27,495	$58,115
12	Allocation	53%	47%	100%
13	Revenue Requirement	$26,344	$23,656	$50,000
14	**$ per MWH**	**52.69**	**47.31**	**50.00**

* Assumes a functional revenue requirement of $50,000.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/304

EXAMPLE OF IMPACT OF SEASONAL USAGE

ON MARGINAL COST RESULTS

July 12, 2006

PACIFICORP
Example of Impact of Seasonal Usage on Marginal Cost Results
Using 2007 Mid-C Monthly Prices

Ln		Class A (1)	Class B (2)	Total (3)
1	Energy @ Generation (MWH)	500	500	1000
2	System Load Factor (12CP)	76.10%	76.10%	
3	Peak kW @ generator (kW)	75.00	75.00	150.00
4	***Marginal Cost***			
5	Energy @ Generator	500	500	
6	Unit MC - Generation Energy $/MWH	$71.57	$68.70	
7	Marginal Cost using Mid-C	$35,783	$34,349	$70,133
8	System Demand	75.00	75.00	
9	Unit MC - Generation Capacity $/kW	$74.31	$74.31	
10	Marginal Cost	$5,573	$5,573	$11,147
11	Total Marginal Cost	$41,357	$39,923	$81,279
12	Allocation	51%	49%	100%
13	Revenue Requirement	$25,441	$24,559	$50,000
14	**$ per MWH**	**50.88**	**49.12**	**50.00**

	Energy (MWH) Class A	Energy (MWH) Class B	2007 Mid-C Prices
Jan	60.22	40.62	$90.19
Feb	49.54	37.63	$87.31
Mar	43.21	41.77	$76.80
Apr	36.26	41.66	$59.01
May	28.94	42.48	$43.98
Jun	32.99	44.08	$40.99
July	36.91	44.75	$63.99
Aug	35.86	45.89	$77.31
Sep	31.12	41.86	$73.46
Oct	37.93	41.18	$67.10
Nov	51.34	39.48	$71.55
Dec	55.67	38.61	$77.31
	500.00	500.00	

* Assumes a functional revenue requirement of $50,000.

PACIFICORP
Example of Impact of Seasonal Usage on Marginal Cost Results
Using 20-Year Levelized Mid-C Prices

Ln		Class A (1)	Class B (2)	Total (3)
1	Energy @ Generation (MWH)	500	500	1000
2	System Load Factor (12CP)	76.10%	76.10%	
3	Peak kW @ generator (kW)	75.00	75.00	150.00
4	***Marginal Cost***			
5	Energy @ Generator	500	500	
6	Unit MC - Generation Energy $/MWH	$51.25	$49.73	
7	Marginal Cost using Mid-C	$25,627	$24,863	$50,489
8	System Demand	75.00	75.00	
9	Unit MC - Generation Capacity $/kW	$74.31	$74.31	
10	Marginal Cost	$5,573	$5,573	$11,147
11	Total Marginal Cost	$31,200	$30,436	$61,636
12	Allocation	51%	49%	100%
13	Revenue Requirement	$25,310	$24,690	$50,000
14	**$ per MWH**	**50.62**	**49.38**	**50.00**

	Energy (MWH) Class A	Energy (MWH) Class B	20-yr Levelized Mid C Prices
Jan	60.22	40.62	$61.41
Feb	49.54	37.63	$57.69
Mar	43.21	41.77	$51.82
Apr	36.26	41.66	$44.46
May	28.94	42.48	$37.04
Jun	32.99	44.08	$36.58
July	36.91	44.75	$47.30
Aug	35.86	45.89	$54.46
Sep	31.12	41.86	$51.79
Oct	37.93	41.18	$48.32
Nov	51.34	39.48	$52.02
Dec	55.67	38.61	$56.15
	500.00	500.00	

* Assumes a functional revenue requirement of $50,000.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/305

ESTIMATED EFFECT OF PROPOSED PRICE CHANGE

July 12, 2006

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, 2007

		Present Revenues ($000)					Proposed Revenues ($000)					Change				
		Base Rates	Misc Adders	RMA	Total Adders	Net Rates	Base Rates	Misc Adders	RMA	Total Adders	Net Rates	Base Rates ($000)	Base Rates %	Net Rates ($000)	Net Rates %	Ratio
1	Residential	$422,917	$1,465	$0	$1,465	$424,382	$487,971	$1,465	$0	$1,465	$489,436	$65,054	15.4%	$65,054	15.3%	1.17
2	Schedule 23	$90,122	$821	($6,463)	($5,642)	$84,480	$93,123	$821	$0	$821	$93,944	$3,001	3.3%	$9,464	11.2%	0.85
3	Schedule 28	$110,982	$1,328	$7,890	$9,218	$120,200	$129,768	$1,328	$1,584	$2,912	$132,680	$18,786	16.9%	$12,480	10.4%	0.79
4	Schedule 30	$65,688	$852	$2,798	$3,650	$69,338	$76,666	$852	$1,016	$1,868	$78,534	$10,978	16.7%	$9,196	13.3%	1.01
5	Schedule 48T	$128,855	$1,903	($2,181)	($278)	$128,577	$140,232	$1,903	$0	$1,903	$142,135	$11,376	8.8%	$13,557	10.5%	0.80
6	Schedule 47	$9,039	$117	($146)	($29)	$9,010	$9,870	$117	$0	$117	$9,987	$831	9.2%	$977	10.8%	0.82
7	Schedule 41	$10,468	$76	($2,600)	($2,524)	$7,944	$11,351	$76	($2,600)	($2,524)	$8,827	$883	8.4%	$883	11.1%	0.85
8	Schedule 33	$915	$0	$0	$0	$915	$915	$0	$0	$0	$915	$0	0.0%	$0	0.0%	0.00
9	Lighting	$5,709	$32	$551	$583	$6,292	$6,843	$32	$0	$32	$6,875	$1,134	19.9%	$583	9.3%	0.70
10	Total Sales to Ultimate Consumers	$844,695	$6,594	($151)	$6,443	$851,138	$956,739	$6,594	$0	$6,594	$963,333	$112,043	13.3%	$112,194	13.2%	1.00
11	Employee Discount	($418)	($1)	$0	($1)	($419)	($482)	($1)	$0		($482)	($64)	15.4%	($63)	15.1%	1.15
12	Total Sales w/ Employee Discount	$844,277	$6,593	($151)	$6,442	$850,719	$956,256	$6,593	$0	$6,594	$962,850	$111,979	13.3%	$112,131	13.2%	1.00
13	AGA Revenue	$1,554	$0	$0	$0	$1,554	$1,554	$0	$0	$0	$1,554	$0	0.0%	$0	0.0%	0.00
14	Total Sales w/ Employee Discount & AGA	$845,831	$6,593	($151)	$6,442	$852,273	$957,810	$6,593	$0	$6,594	$964,404	$111,979	13.2%	$112,131	13.2%	1.00

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

DIRECT TESTIMONY OF

JAMES SELECKY

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

(Confidential Information Omitted)

July 12, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

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

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

A. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU's membership consists of industrial companies who are some of PacifiCorp's (or the "Company") largest customers.

Q. WHAT ARE THE SUBJECTS COVERED IN YOUR TESTIMONY?

A. My testimony addresses the appropriate level of health care, pension and other retirement costs that should be included in the test year revenue requirement. In addition, I address the treatment of the Regional Transmission Organization ("RTO") expenses, memberships and subscriptions, incentive programs, certain Administrative and General ("A&G") expense items (manpower levels and legal costs), and the level of State and Federal income taxes that should be included in PacifiCorp's revenue requirement. My testimony and that of the other ICNU witnesses address many, but not all, of the issues raised in the Company's filing. The fact that ICNU's witnesses have not addressed an issue should not be construed as an endorsement of PacifiCorp's position. In addition, ICNU may support or adopt issues and adjustments proposed by other parties.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. My adjustments reduce PacifiCorp's Oregon jurisdictional revenue requirements by approximately $31.950 million. My recommendations are as follows:

1. PacifiCorp's test year medical insurance costs are overstated.

2. The Oregon Public Utility Commission ("OPUC" or the "Commission") should reject PacifiCorp's proposal to escalate medical costs at 10% and should escalate those costs at 9%, which represents an average of current industry projections.

3. PacifiCorp's health care costs should be adjusted to reflect a larger contribution from employees. PacifiCorp indicates that in 2004, employee contributions were 15%, while data indicates that employee contributions are approximately 22% on a total industry-wide basis.

4. Escalating PacifiCorp's medical costs at a rate of 9% and reducing these costs for a greater employee contribution lowers the total Company expense by $5.208 million, and the Oregon jurisdictional revenue requirement by $1.143 million.

5. PacifiCorp has included in its test year revenue requirement an electric pension expense of $56.4 million on a total Company basis. The Commission should revise PacifiCorp's pension expense utilizing a more reasonable discount rate, pension fund earning rate and salary escalation rate.

6. Increasing PacifiCorp's pension expense discount rate from 5.75% to 6.00%, increasing the fund earning rate from 8.75% to 9.0%, and reducing the salary escalation rate from 4% to 3% produces a total Company electric pension expense adjustment of $40.8 million and a jurisdictional Oregon revenue requirement adjustment of $3.317 million.

7. PacifiCorp has included in its revenue requirement for IBEW 57 employees a pension expense contribution of $7.3 million. Since PacifiCorp's contributions in 2005 and 2006 were less than initially forecasted ($0 and $1.048 million, respectively), the Commission should reduce PacifiCorp's IBEW 57 pension contribution expense for 2006 to $2.338 million. This produces an Oregon jurisdictional revenue requirement adjustment of $1.096 million.

8. PacifiCorp's expense for post-retirement benefits other than pension should be based on a higher discount rate and fund earning rate.

9. Utilizing a discount rate of 6.0% and a fund earnings rate of 9.0% reduces the test year post-retirement benefits and other expenses from $28.2 million to $25.1 million and the Oregon jurisdictional revenue requirement by $692,000.

10. PacifiCorp's RTO costs should be excluded from its revenue requirement because these costs are non-recurring and will not provide any benefits to ratepayers. This reduces PacifiCorp's Oregon revenue requirement by $630,000.

11. PacifiCorp's proposed expense for membership and subscriptions should be reduced to exclude all national and regional trade organization costs except for the costs associated with participating in the Western Electricity Coordinating Council ("WECC"). Excluding these costs reduces PacifiCorp's Oregon revenue requirement by $239,000.

12. The Commission should exclude 100% of the executive incentive costs and 50% of the non-executive incentive costs from PacifiCorp's revenue requirement. Excluding these expenses reduces PacifiCorp's Oregon jurisdictional revenue requirement by approximately $3.805 million.

13. PacifiCorp's A&G expense should be reduced to reflect reductions in the level of manpower that PacifiCorp has included in its test year revenue requirement. As a result of manpower reductions, PacifiCorp's Oregon A&G expense should be reduced by [redacted].

14. PacifiCorp has overstated its A&G expense associated with internal and outside legal costs. The Commission should utilize the fiscal year ("FY") 2006 legal costs to develop PacifiCorp's test year revenue requirement. Using the FY 2006 legal costs reduces PacifiCorp's A&G expense on an Oregon jurisdictional basis by [redacted] million.

15. PacifiCorp has overstated its Federal and State income taxes that are paid to governmental units. PacifiCorp failed to file this rate case in accordance with Senate Bill ("SB") 408 and its rules.

16. The Commission should recognize in PacifiCorp's ratemaking formula the income tax benefits associated with the increased debt of MidAmerican Energy Holdings Company ("MEHC"). Reflecting this debt in the calculation of the Federal and State income taxes reduces PacifiCorp's Oregon jurisdictional revenue requirement by approximately $19.454 million.

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

A. Table 1 below summarizes the impact of my proposed adjustments on PacifiCorp's Oregon revenue requirement.

TABLE 1

Summary of Revenue Requirement Adjustments
(000)

Description	**Oregon Jurisdiction ***
Health Care	$1,143
Pension Expense	$3,317
IBEW 57	$1,096
Post Retirement Benefit, Other Than Pension	$692
RTO Expense	$630
Memberships	$239
Incentive Compensation	$3,805
A&G Expense (Manpower and Legal Costs)	$1,574
Consolidated Tax Adjustment	$19,454
Total	**$31,950**

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

Q. WHAT IS THE IMPACT ON PACIFICORP'S REVENUE REQUIREMENT OF ALL OF ICNU'S ADJUSTMENTS?

A. ICNU and CUB joint witness Michael Gorman is addressing cost of capital and return on equity. ICNU witness Randall Falkenberg is addressing net power costs, and certain non-power cost issues, including the Western Area Power Administration contract, Senate Bill 1149 costs, and thermal overhaul costs. Table 2 below summarizes the total adjustments proposed by ICNU in this proceeding. As previously stated, ICNU may adopt or support additional revenue requirement adjustments proposed by other parties; thus, Table 2 should not be viewed as ICNU's final, complete recommendation.

TABLE 2

Summary of ICNU Proposed Adjustments
(000)

Description	**Oregon Jurisdiction**
Power Cost Adjustments	$43,918
Health Care	$1,143
Pension Expense	$3,317
IBEW 57	$1,096
Post Retirement Benefit, Other Than Pension	$692
RTO Expense	$630
Memberships	$239
Incentive Compensation	$3,805
A&G Expense (Manpower and Legal Costs)	$1,574
Consolidated Tax Adjustment	$19,454
Thermal Overhaul	$2,959
WAPA Revenue	$835
SB 1149 Costs	$1,406
Return on Equity	$30,000
Capital Structure	$10,000
Total ICNU Proposed Adjustments	**$121,068**

I. HEALTH CARE COSTS

Q. WHAT LEVEL OF MEDICAL BENEFITS IS INCLUDED IN PACIFICORP'S REVENUE REQUIREMENT IN THIS CASE?

A. On a total Company basis, PacifiCorp has included medical insurance costs in its forecasted test year of $50.303 million. PPL/901, tab 4.3.19.

Q. WHAT LEVEL OF MEDICAL COST INCREASES IS PACIFICORP FORECASTING FOR THE TEST YEAR?

A. To determine the level of health care costs, PacifiCorp is projecting an annual increase of 10% for 2006 and 2007. To develop its test year health care costs, PacifiCorp utilized its actual 2005 costs and escalated it by 10% per year.

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

A. No. PacifiCorp acknowledges in the testimony of Daniel Rosborough that the national trends in cost escalation for health care for the period 2005 through 2007 range between 8% to 10%. PPL/800, Rosborough/9. Even though the Company acknowledges a range of 8% to 10%, it utilized the high end of the range to calculate its forecasted pension expense.

The Commission should, at a minimum, utilize the mid-point of the range for purposes of determining the test year health care expense.

Q. WHAT SUPPORT DOES THE COMPANY PROVIDE FOR UTILIZING THE HIGH END OF THE RANGE?

A. Mr. Rosborough states that medical health care cost trends in the electric and gas utility industry have been approximately 3% higher than the general industry. However, Mr. Rosborough also indicates that PacifiCorp's electric operation group has experienced a six-year increase of 68.6% in medical costs, while the national average for the same types of plans have increased 75.3%. PPL/800, Rosborough/9. PacifiCorp's costs have increased at less than the national rate and there are no grounds to assume that PacifiCorp's costs will suddenly increase at a rate higher than the general industry average. Therefore, based on PacifiCorp's recent history, the Commission should utilize no more than the mid-point of the acceptable range. An adjustment based on the mid-point is conservative, as it could be argued that a larger adjustment is warranted to fully account for the fact that PacifiCorp's medical costs have increased at a lower rate than the national average.

Q. IS THERE ANY INDUSTRY SUPPORT FOR UTILIZING THE RANGE OF 8% TO 10% FOR PURPOSES OF DEVELOPING HEALTH CARE COSTS?

A. Yes. In the 2006 Towers Perrin health care survey of more than 2,000 of the largest US employers, Towers Perrin stated that US companies are facing an increase of 8% in their 2006 health care costs. In addition, a 2006 survey of health care costs performed by Hewitt Associates indicates that the anticipated overall cost increase on average is expected to be 10%. These two national surveys support an escalation rate of between 8% to 10%.

Although these surveys represent 2006 costs, this range is appropriate for developing PacifiCorp's 2007 health care costs. It should be noted that the Hewitt Associates survey indicates that since 2003, the rate of inflation for health care costs has decreased annually from a high of 16% in 2003 to 10% in 2006. There seems to be a trend toward lower levels of health care cost inflation.

Q. WHAT IS YOUR RECOMMENDATION FOR THE APPROPRIATE ESCALATION RATE TO BE UTILIZED FOR HEALTH CARE COSTS?

A. Based on Mr. Rosborough's testimony and my review of the national surveys, I recommend the Commission utilize an escalation rate of 9% to develop PacifiCorp's revenue requirement.

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

A. Yes. In Mr. Rosborough's testimony, he states that for 2006, the Company subsidy has decreased to 85% of the total medical program costs. PPL/800, Rosborough/11. Although PacifiCorp has increased the percentage of employee contribution, it is still below industry average.

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

A. Based on surveys conducted by Hewitt Associates and Towers Perrin, employees are picking up approximately 22% of health care costs on average. Specifically, a Towers Perrin survey states the following regarding the percent of costs that employees pay:

> Overall, employers will pay 80% of premium costs and employees will pay 20% -- roughly the same cost-sharing formula that has prevailed for the past several years among large U.S. companies.

Likewise, a survey performed by Hewitt Associates indicates that for 2006, the average employee would contribute approximately 23% of the health care costs, while the average dependent coverage would require a contribution of 27%. Thus, the average level of employee compensation in the Hewitt Associates survey is 25%.

Q. WHAT IS YOUR RECOMMENDATION FOR THE EMPLOYEE CONTRIBUTION LEVEL THAT SHOULD BE UTILIZED TO CALCULATE PACIFICORP'S TEST YEAR MEDICAL EXPENSE?

A. Based on the results of the Towers Perrin (20% employee compensation) and Hewitt Associates (25% employee compensation) surveys, I am recommending that the Commission utilize an employee contribution level of 22%. This essentially is a conservative adjustment because it represents the low range of an average of those two surveys.

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

A. The health care costs should reflect a 9% escalation rate and a 22% employee contribution. To calculate the appropriate level of health care costs, I have used PacifiCorp's test year health care costs as the starting point. I then adjusted the health care 33 months back to the historic period (12 months ending March 2005) using PacifiCorp's annual rate of inflation of 10% for medical costs. Next, I adjusted the medical costs to reflect an annual inflation rate of 9% and employee contributions of 22%—not the 15% used to develop the test year cost.

These adjustments reduce PacifiCorp's 2007 health care costs on a total Company basis from $50.303 million to $45.024 million. A summary of this adjustment is shown in Exhibit ICNU/202.

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

A. As Exhibit ICNU/202 shows, I have reduced the level of health care costs on a total Company basis by $5.208 million in the test year. Utilizing the Oregon allocation factor of 28.442% and an expense allocation factor of 73.51%, PacifiCorp's health care expense is reduced by $1.089 million and its test year revenue requirement is reduced by $1.143 million. The difference between the expense and revenue requirement reflects an estimate of the impact on the portion that is capitalized.

II. PENSION EXPENSES

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

A. PacifiCorp projected a total Company electric pension expense of $54.6 million in the test year, which is a 2007 calendar year ("CY"). As indicated in the testimony of PacifiCorp witness Rosborough, the calendar year 2007 pension expense was developed using the actual CY 2005 expense prepared by Hewitt Associates as a baseline. As indicated in PacifiCorp Exhibit PPL/901, tab 4.3.19, the pension expense adjustment represents a $10.7 million increase from the historic period, which is the 12 months ending March 2005. As a means of comparison for calendar years 2002 through 2005, PacifiCorp's pension expense has been $0.5 million, $14.8 million, $31.5 million, and $49.9 million, respectively.

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

A. Key assumptions that can influence the level of pension expense are the discount rate utilized to present value of the benefits, the expected return on pension fund assets, and future salary escalation rates.

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

A. My recommendation in this case is to revise PacifiCorp's actuarial study assumptions for the discount rate, the expected return on pension fund assets, and the estimated level of salary increases. These key factors influence the level of pension expense. Making adjustments for these three factors reduces PacifiCorp's total pension expense from $54.6 million to $40.8 million on a total company basis.

Q. WHAT ASSUMPTIONS WERE UTILIZED TO CALCULATE PACIFICORP'S PROPOSED LEVEL OF PENSION EXPENSE?

A. PacifiCorp assumed a discount rate of 5.75%, a salary increase rate of 4% per year, and an expected long-term rate of return of 8.75%. PPL/800, Rosborough/4.

Q. DO YOU BELIEVE THAT PACIFICORP'S ASSUMPTIONS FOR THE DISCOUNT RATE, SALARY INCREASE RATE, AND EXPECTED LONG-TERM RATE OF RETURN ARE APPROPRIATE?

A. No. I will discuss each of these items separately.

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

A. The discount rate that was utilized to calculate the test year pension expense is 5.75%. PacifiCorp argues that the 5.75% discount rate is at the upper end of the reasonable range and as a result, the Company claims this produces the lowest possible pension expense. I disagree because a higher discount rate is appropriate and produces a more reasonable pension expense. The level of pension expense is dependent upon the discount rate. Increasing the discount rate reduces the pension expense, while decreasing the discount rate increases the pension expense. In response to the Federal government raising interest rates, there is an expected increase in the interest rates for bonds. This increase in interest rates affects the discount rate. Therefore, as interest rates rise, the discount rate should also rise.

Q. WHAT IS YOUR SUPPORT FOR THE CLAIM THAT INTEREST RATES SHOULD RISE?

A. This is based in part on PacifiCorp witness Dr. Hadaway's testimony. Dr. Hadaway projects significant increases in the interest rates. Dr. Hadaway states in his testimony that ten-year Treasury notes and long-term Treasury bonds are expected to increase by 80 basis points or 0.8% from the February 2006 level through the first quarter of 2007.

PPL/200, Hadaway/30. Dr. Hadaway also indicates that corporate bonds are projected to increase by 80 basis points or 0.8% over the same period of time. Id. Since the discount rate represents an interest rate, increasing the discount rate by only 25 basis points or 0.25% is justifiable and extremely conservative relative to the Company's alleged expectations of future interest rates.

As indicated in the testimony of PacifiCorp witness Rosborough, the discount rate is based on Moody's Corporate Aa bond yield. PPL/800, Rosborough/4. Therefore, if PacifiCorp is expecting bond yields to increase by 0.8%, then an increase in the discount rate of 0.25% represents a conservative increase. Finally, it should be noted that the yield on Aa rated corporate bonds as reported by Moody's is currently 6.21%. Exhibit ICNU/203. This further supports increasing the discount rate to at least 6.0%.

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

A. PacifiCorp proposed that an expected return on assets of 8.75% should be utilized to determine its pension expense. Table 3 below shows the type of investment and the return that PacifiCorp states that it expects to receive from those investments.

TABLE 3

Expected Return on Pension Assets

Type of Investment	Weighting	Expected Return	Weighted Cost
Equities	55%	9.25%	5.09%
Bonds	35%	6.5%	2.28%
Private Holdings	10%	14%	1.40%
Total Return			8.76%

Source: PacifiCorp's response to ICNU data request ("DR") 7.1.

PacifiCorp's proposed 8.75% return on plant assets is based on its assumed expected returns for the various types of investments.

Q. DO YOU HAVE ANY RECOMMENDED CHANGES TO THE EXPECTED RETURN ON PENSION ASSETS?

A. Yes. The return on pension assets should be increased from the 8.75% proposed by PacifiCorp to 9.0%. My proposed 0.25% increase in the expected return on pension assets is based in part on Dr. Hadaway's projection that there will be increases in the level of interest rates on long-term Treasury and corporate bonds. My testimony does not support Dr. Hadaway's claims that there will be an 80 basis point increase in interest rates. I am conservatively recommending an increase in the expected return on pension assets of 25 basis points from the Company's proposed level of 8.75%. As a result, the Commission should utilize a 9.0% expected return on plant assets.

Q. YOU PREVIOUSLY INDICATED THAT PACIFICORP UTILIZED AN ANNUAL ESCALATION RATE FOR A SALARY INCREASE OF 4% TO DETERMINE ITS FUTURE PENSION OBLIGATIONS. DO YOU BELIEVE THAT IS AN APPROPRIATE ESCALATION RATE?

A. No. The Annual Energy Outlook of 2006, published by the Energy Information Administration of the Department of Energy, provides projections for the consumer price index ("CPI") and gross national product ("GNP") price deflator for 2004 through 2030. These projections indicate that the CPI will be approximately 2.7% per year and the GNP price deflator will be 2.5% per year for this approximate 25-year period. These projections are more than 1 full percentage point below the level of salary increases that PacifiCorp utilized to determine its pension obligations. Therefore, I recommend that a 3% salary increase rate be utilized to develop the appropriate level of pension expense that should be included in this case. Again, my recommendation is conservative because a lower salary increase could be supported based on the CPI and the GNP price deflator.

Q. WHAT IS YOUR RECOMMENDATION FOR THE APPROPRIATE LEVEL OF PENSION EXPENSE FOR PACIFICORP?

A. I am proposing a total Company electric pension expense of $40.8 million for calendar year 2007, which is the test year. This figure was developed by PacifiCorp in response to OPUC DR No. 154. Exhibit ICNU/204. The bottom of page 2 of Exhibit ICNU/204 shows the major assumptions utilized to calculate the pension expense of $40.8 million. This reduces PacifiCorp's total electric pension expense from $56.4 million to $40.8 million. This adjustment reduces the Oregon expense by $3.159 million and the Oregon revenue requirement by $3.317 million. This includes an adjustment for the reduction in expense and an estimate of the reduction in the portion of the pension-related expenses that are capitalized.

III. IBEW PENSION EXPENSES

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

A. No. PacifiCorp has an agreement with IBEW 57 that requires PacifiCorp to make annual contributions to IBEW 57's pension fund. PacifiCorp is forecasting that it would make a contribution to IBEW 57's pension fund of $7.332 million in the test year.

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

A. Yes. PacifiCorp's total Company proposed IBEW pension expense of $7.332 million should be reduced to $2.338 million. This represents an average of the total IBEW 57 pension expense over the last five years, or from FY 2002 through FY 2006. PacifiCorp provided its contributions to the IBEW 57 pension plan for the period FY 2002 through FY 2006 in response to OPUC Data Request Nos. 37 and 272. Exhibit ICNU/205.

Q. WHY DO YOU BELIEVE THAT THIS ADJUSTMENT IS APPROPRIATE?

A. In PacifiCorp's last rate proceeding, UE 170, PacifiCorp forecasted that it would make contributions to IBEW 57's pension fund of $3 million in both 2005 and 2006. As shown in Exhibit ICNU/205, in FY 2005 and FY 2006, PacifiCorp's forecasts were highly inaccurate as PacifiCorp made contributions of $0 and $1.048 million, respectively. Therefore, given the unpredictability and volatility of this expense, and the Company's ratemaking level for this expense, it should be based on the average of the last five years. Utilizing a single year projection is inappropriate.

Q. WHAT IS THE IMPACT ON PACIFICORP'S REVENUE REQUIREMENT OF REDUCING THE IBEW 57 PENSION EXPENSE TO $2.338 MILLION?

A. Reducing the IBEW 57 pension expense to $2.338 million reduces PacifiCorp's IBEW 57 pension expense by $4.993 million on a total Company basis, and PacifiCorp's

Oregon jurisdictional revenue requirement by $1.096 million. The revenue requirement adjustment includes a reduction in expense and an estimate of reduction in the revenue requirement associated with the capitalized costs.

IV. POST-RETIREMENT BENEFITS OTHER THAN PENSION

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

A. Yes. The adjustment I made to FAS 106 expense is similar to the adjustment I made to pension expense. That is, I adjusted the discount rate and the expected return on assets. I developed a level of FAS 106 cost assuming a discount rate of 6.0% as opposed to the Company's 5.75% and I increased the expected return on assets from 8.75% to 9.00%. The reasons for adjusting the discount rate and expected return on assets for FAS 106 are the same reasons that I outlined above in my testimony regarding pensions.

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

A. The impact of my FAS 106 adjustments is to reduce PacifiCorp's proposed Company expense of $28.2 million to $25.1 million. On an Oregon jurisdictional basis, this adjustment reduces PacifiCorp's FAS 106 revenue requirement by $692,000.

V. RTO DEVELOPMENT COSTS

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

A. Yes. On a total Company basis, PacifiCorp has included $2.219 million of RTO costs in its test year revenue requirement. On an Oregon jurisdictional basis, the expense is $630,000. Exhibit ICNU/206 (PacifiCorp response to ICNU DR No. 7.23).

Q. DO THE RTO EXPENSES PROVIDE BENEFITS TO RATEPAYERS?

A. No. Currently a Northwest RTO is not operating and may never operate. As a result, the expenses associated with the development of the RTO are neither used nor useful in supplying service to Oregon ratepayers. Therefore, these alleged costs should not be passed on to ratepayers.

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

A. Because this expense is not providing a current benefit to ratepayers, recovery of these costs should be denied. Furthermore, to the extent these costs actually exist, it appears clear that PacifiCorp is not currently incurring these expenses since the demise of GridWest. Therefore, the $630,000 of RTO expenses PacifiCorp has included in its test year revenue requirement should be excluded.

Q. IN A PREVIOUS ANSWER, YOU INDICATED THAT THE RTO MAY NEVER OPERATE. WHAT IS YOUR BASIS FOR THAT STATEMENT?

A. On April 11, 2006, Grid West issued a news release that stated that the Grid West Board of Directors voted to dissolve Grid West. A copy of that Grid West news release is attached as Exhibit ICNU/207. The fact that Grid West has ceased operations demonstrates that PacifiCorp is unlikely to actually incur its alleged RTO-related costs. The Commission should cease including RTO costs in customer rates until it has reasonable assurance that the costs will actually be incurred and that an RTO will be created that provides measurable benefits to the Oregon ratepayers.

VI. MEMBERSHIP AND SUBSCRIPTIONS

Q. HAS THE COMPANY PROPOSED AN ADJUSTMENT TO THE LEVEL OF MEMBERSHIP AND SUBSCRIPTION COSTS THAT ARE INCLUDED IN ITS REVENUE REQUIREMENT?

A. Yes. As indicated in PacifiCorp witness Paul Wrigley's testimony, the Company is proposing to remove expenses for memberships and subscriptions in excess of the Commission's policy pursuant to the Commission Order in Docket No. UE 94. This adjustment removes 25% of the national and regional trade organizations and includes

100% of the WECC. All of the WECC dues are included for ratemaking because PacifiCorp is required to be a member. PPL/900, Wrigley/16. All other membership dues should be removed.

Q. WHAT IS THE LEVEL OF MEMBERSHIP AND SUBSCRIPTION EXPENSES THAT ARE INCLUDED IN PACIFICORP'S REVENUE REQUIREMENT?

A. As shown on page 4.17.1 of Exhibit PPL/901, PacifiCorp has included on a total Company basis $847,000 of mandated membership dues associated with WECC and $840,000 of dues associated with national and regional trade organizations.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE LEVEL OF MEMBERSHIP AND SUBSCRIPTION EXPENSE THAT SHOULD BE INCLUDED IN PACIFICORP'S REVENUE REQUIREMENT?

A. I recommend that the Commission exclude all national and regional trade membership allowances. The Company has not established that participating in these organizations provides benefits to ratepayers. Membership in many of these organizations primarily benefits shareholders, not ratepayers. For example, many of these organizations engage in political activities, serve promotional purposes, and promote business development. In addition, with increasing energy costs, utilities should pursue avenues to reduce costs to ratepayers. Absent a clear showing of any benefits to ratepayers associated with any of the trade organizations, the Commission should exclude this expense from PacifiCorp's revenue requirement.

Q. WHAT IS THE IMPACT ON THE OREGON REVENUE REQUIREMENT OF REMOVING ALL NATIONAL AND REGIONAL TRADE MEMBERSHIP ALLOWANCES FROM THE OREGON JURISDICTIONAL REVENUE REQUIREMENT?

A. Removing the national and regional trade membership allowances of $839,857 from the total Company revenue requirement reduces the Oregon revenue requirement by $238,872.[1/]

VII. INCENTIVE PROGRAMS

Q. HAS PACIFICORP INCLUDED ANY COSTS ASSOCIATED WITH INCENTIVE PROGRAMS IN ITS TEST YEAR REVENUE REQUIREMENT?

A. PacifiCorp has included in its revenue requirement $33.649 million of incentives on a total Company basis. PPL/901, tab 4.3.1.

Q. ARE YOU PROPOSING ANY ADJUSTMENT TO THE COMPANY'S INCENTIVE COSTS?

A. Yes. I am recommending that 100% of the executive incentive costs be excluded and that the non-executive incentives be shared equally by ratepayers and shareholders. As a result, the non-executive portion of the incentive expense would be reduced by 50%.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATIONS FOR EXCLUDING 100% OF THE EXECUTIVE INCENTIVES AND 50% OF THE NON-EXECUTIVE EMPLOYEE INCENTIVES?

A. First, it is not appropriate to include additional compensation for PacifiCorp's top 12 executives. As indicated in response to OPUC DR No. 283 (Exhibit ICNU/208), the additional compensation for these 12 executives is approximately $78,000 each. Any additional compensation that the executives receive should come from shareholders. Second, it is not clear as to how the annual incentive program will actually be administered in calendar year 2007. As indicated in response to OPUC DR 297 (Exhibit

[1/] $839,857 * 28.442%. Exhibit PPL/901, tab 4.17.

ICNU/209), details surrounding the administration and implementation of the annual incentive program in calendar year 2007 are not yet known.

Third, a review of the measures that are applied to determine the amount of incentive compensation for all employees indicates that a portion of the incentives are based on corporate or business performance. Incentives related to financial performance should be considered differently because they can be inconsistent with service quality, safety, reliability, and affordable electric rates. Shareholders, not ratepayers, benefit from incentives related to the utility's financial performance. Since it is likely that both shareholders and ratepayers may benefit from the program, an equal sharing for the non-executive incentive program is appropriate.

Q. ARE THERE ANY OTHER CONSIDERATIONS REGARDING YOUR PROPOSED TREATMENT OF THE INCENTIVE PROGRAMS?

A. A review of PacifiCorp's compensation and benefits as shown on its web site indicates that PacifiCorp offers, in addition to an incentive program, a competitive base pay. Therefore, the incentives are not needed to attract qualified employees. Although a complete disallowance may be appropriate, for purposes of this case, I am willing to assume that both ratepayers and shareholders benefit from this program, and I am recommending a 50/50 sharing of the non-executive costs.

Q. WHAT IS THE IMPACT ON PACIFICORP'S REVENUE REQUIREMENT OF EXCLUDING 100% OF THE EXECUTIVE COMPENSATION AND 50% OF THE NON-EXECUTIVE COMPENSATION?

A. Excluding all of the executive compensation and reducing the non-executive compensation by 50% reduces PacifiCorp's jurisdictional Oregon revenue requirement by $3.805 million. This is summarized on Exhibit ICNU/210.

VIII. ADMINISTRATIVE AND GENERAL EXPENSE

Q. DO YOU HAVE ANY ADJUSTMENTS TO MAKE TO PACIFICORP'S PROPOSED LEVEL OF A&G EXPENSE?

A. Yes. I am proposing adjustments to the level of A&G expense associated with manpower levels and internal and outside legal costs.

Q. IS PACIFICORP PROPOSING A CAP TO ITS A&G EXPENSE IN THIS CASE?

A. Yes. PacifiCorp is proposing to cap its A&G expense at $231.5 million. PacifiCorp states that its actual A&G expense is $249.0 million, or $17.5 million more than its proposed cap. It is unclear, however, whether the $249 million reflects an inflated amount of A&G expense.

Q. WILL YOUR A&G EXPENSE ADJUSTMENTS IMPACT THE LEVEL OF A&G EXPENSE THAT PACIFICORP HAS INCLUDED IN ITS REVENUE REQUIREMENT?

A. I am seeking an interpretation from the Commission relative to the level of A&G expense that PacifiCorp should be allowed for ratemaking purposes. Although my proposed adjustments are based on PacifiCorp's actual level of A&G expense, it is not clear to me whether these adjustments would come off the A&G expense cap in their entirety. My testimony identifies the expenses that I determined to be overstated or nonrecurring. It is important to note that I do not have a budget to verify the prudency of the entire $249 million claimed by PacifiCorp.

Q. ARE YOU PROPOSING ANY ADJUSTMENTS TO THE LEVEL OF MANPOWER OR FULL-TIME EQUIVALENT EMPLOYEES THAT PACIFICORP USED TO ESTABLISH ITS ACTUAL A&G EXPENSE?

A. Yes. In response to ICNU DR No. 12.2 (Confidential Exhibit ICNU/211), PacifiCorp provided confidential information regarding its current manpower level. This information shows there has been a reduction in its manpower level related to A&G

expense of [redacted] full-time equivalent employees ("FTEs") from the levels used to develop the test year revenue requirement. As that data response shows, the decline in FTEs reduces PacifiCorp's Oregon A&G expense by [redacted]. This adjustment reflects the manpower levels as of May 16, 2006.

Q. HAS PACIFICORP ANNOUNCED ANY OTHER REDUCTIONS IN ITS A&G MANPOWER?

A. Yes. In response to ICNU DR No. 15.5 (Confidential Exhibit ICNU/212), PacifiCorp provided confidential information that indicated as of June 9, 2006, the Company has notified additional employees of displacement related to the acquisition of PacifiCorp by MEHC. The result of this is an additional decrease of [redacted] FTEs since the Company responded to ICNU DR No. 12.2 (Confidential Exhibit ICNU/211). Utilizing this data prepared by the Company, the reduction in [redacted] FTEs further reduces the A&G expense on an Oregon jurisdictional basis by [redacted].

Q. WHAT IS THE TOTAL IMPACT OF YOUR ADJUSTMENT TO A&G EXPENSE FOR REDUCTIONS IN PACIFICORP'S LEVEL OF MANPOWER?

A. Eliminating [redacted] FTEs results in a reduction in the Oregon allocation A&G expense of [redacted]. MEHC may be planning additional employee reductions that are not incorporated in this adjustment. I may update this adjustment in surrebuttal testimony.

Q. DO YOU HAVE ANY OTHER ADJUSTMENTS TO MAKE TO PACIFICORP'S LEVEL OF A&G EXPENSE?

A. Yes. PacifiCorp has overstated the level of legal expense that is included in its A&G expense.

Q. WHAT IS YOUR BASIS FOR THAT CONCLUSION?

A. PacifiCorp's responses to ICNU DR Nos. 11.6 and 11.7 (Confidential Exhibit ICNU/213) shows that PacifiCorp's number of employees in its legal department has declined from [redacted] in 2005 to [redacted] as of April 2006.

In addition, in response to ICNU DR No. 11.8 (Confidential Exhibit ICNU/214), PacifiCorp provided confidential information regarding the level of its legal expense for FY 2005 and FY 2006. This information shows that the total expense has declined in FY 2005 from [redacted] million to [redacted] million in FY 2006. This represents a decline of approximately [redacted] million in legal expenses. PacifiCorp also states in response to ICNU DR No. 11.8 (Confidential Exhibit ICNU/214) that it does not expect any material changes from the FY 2006 levels in expected legal department costs for the 2006 to 2010 period absent a significant change in the level of regulatory activity. Therefore, the FY 2006 level of expense should be used to develop PacifiCorp's test year revenue requirement.

Q. WHAT LEVEL OF LEGAL EXPENSE HAS PACIFICORP INCLUDED IN ITS TEST YEAR REVENUE REQUIREMENT?

A. PacifiCorp has included in its test year revenue requirement [redacted] million of legal department expense on a total Company basis. Confidential Exhibit ICNU/215 (PacifiCorp response to ICNU DR No. 13.6). This represents an increase in legal expense from FY 2006 level of [redacted] million. This proposed increase in costs is inconsistent with MEHC efforts to reduce PacifiCorp's legal costs.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THE LEVEL OF LEGAL EXPENSE THAT PACIFICORP HAS INCLUDED IN ITS A&G EXPENSE?

A. Yes. In response to ICNU DR No. 15.6 (Confidential Exhibit ICNU/216), PacifiCorp provides its actual outside legal expense for FY 2005 and FY 2006 and its forecasted outside legal expense for CY 2007. The data shows that in FY 2005 the outside legal expense was [redacted] million and in FY 2006, PacifiCorp's outside legal expense was [redacted] million, or [redacted] million less.

Q. WHAT IS PACIFICORP FORECASTING FOR ITS OUTSIDE LEGAL EXPENSE FOR ITS TEST YEAR?

A. For CY 2007, PacifiCorp is forecasting outside legal expense of [redacted] million. This represents an increase from its actual FY 2006 level of [redacted] million, or a [redacted] increase.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE LEVEL OF LEGAL EXPENSE THAT SHOULD BE INCLUDED IN PACIFICORP'S TEST YEAR REVENUE REQUIREMENT?

A. I recommend that the ratemaking legal expense be based on FY 2006 level of [redacted] million. Utilizing this as the appropriate legal expense will reduce PacifiCorp's total Company legal department expense by [redacted] million and its jurisdictional expense by [redacted] million.

Q. HAVE YOU COMPLETED YOUR REVIEW OF PACIFICORP'S LEGAL COSTS?

A. No. I am currently reviewing whether PacifiCorp's legal costs include one time, non-recurring or imprudent expenditures. I am likely to propose an additional legal cost disallowance in my surrebuttal testimony.

Q. WOULD YOU PLEASE SUMMARIZE YOUR PROPOSED REDUCTIONS TO PACIFICORP'S TEST YEAR A&G EXPENSE?

A. My adjustments to reflect reductions in PacifiCorp's manpower levels reduce PacifiCorp's Oregon revenue requirement by [redacted]. My proposed adjustments to the legal expense reduce PacifiCorp's level of A&G expense on an Oregon jurisdictional basis by [redacted] million. Together, these two adjustments reduce PacifiCorp's Oregon A&G expense by $1.574 million. These adjustments may reflect only some of the changes and cost reductions that are occurring at PacifiCorp following the MEHC acquisition.

IX. CONSOLIDATED TAX ADJUSTMENT

Q. ARE YOU PROPOSING AN ADJUSTMENT TO PACIFICORP'S OREGON INCOME TAXES PAID?

A. Yes. I am proposing to reduce PacifiCorp's proposed level of income taxes paid by $12.071 million. This will reduce the Oregon revenue requirement by $19.454 million. My adjustment is consistent with the requirements of SB 408. It is my understanding that the intent of this legislation was to address differences between the income taxes collected by Oregon public utilities in retail rates and the actual taxes by those utilities. I contend that PacifiCorp has overstated its Federal and State income taxes to be paid to units of government. In this instance, it is difficult to determine the precise adjustment because of the manner in which PacifiCorp's taxes are actually paid to the taxing authority. I am continuing my review of this adjustment. Therefore, the details of my adjustment may change when I file my surrebuttal testimony.

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING THE LEVEL OF INCOME TAXES THAT SHOULD BE INCLUDED IN ITS REVENUE REQUIREMENT?

A. PacifiCorp has calculated its estimated income tax liability on a standalone basis, ignoring the policy directives of the legislature and the Commission. The Company has not proposed <u>any</u> adjustment relative to SB 408. PacifiCorp's proposal also ignored the Commission's final order in UE 170 regarding income tax issues. The policy directives in SB 408 and UE 170 should guide the Commission in this proceeding.

Q. HOW DOES PACIFICORP PAY ITS INCOME TAX?

A. PacifiCorp pays its income tax as part of a consolidated tax return. PacifiCorp, which is a subsidiary of MEHC, pays its income tax as part of a consolidated return that is filed by Berkshire Hathaway, Inc. and Subsidiaries ("Berkshire Hathaway"). MEHC is one of the subsidiary companies that files its taxes through Berkshire Hathaway. The overall tax structure is extremely complicated by design and it appears not to render itself to an easy determination of the actual taxes paid. However, the MEHC financials provide insight as to PacifiCorp's actual taxes paid to governmental units. As a result, I recommend that the Commission utilize this data to adjust PacifiCorp's actual taxes paid.

Q. PLEASE BRIEFLY DESCRIBE YOUR PROPOSED TAX ADJUSTMENT.

A. I am proposing a tax adjustment based on the capital structure that exists at MEHC. As previously indicated, PacifiCorp is a subsidiary of MEHC.

The MEHC capital structure is more heavily debt leveraged than PacifiCorp's ratemaking capital structure. As a result, PacifiCorp's taxable income is offset by interest deductions for income tax reporting purposes. Therefore, MEHC's deductible debt interest will reduce the actual income taxes paid to governmental units on a consolidated tax basis. Since interest reduces the actual income taxes paid, the income tax obligation as a result of the MEHC structure is less than the income tax for PacifiCorp on a standalone basis.

Q. WHAT IS MEHC'S CAPITAL STRUCTURE?

A. Table 4 below shows MEHC's capital structure as shown in its 10-Q for the quarter ending March 31, 2006.

TABLE 4

MEHC's Capital Structure as of March 31, 2006

Type	Amount (Millions)	Weight
Senior Debt	$4,476	
Parent Sub Debt	1,355	
Sub Debt	10,600	
Total Debt	$16,431	69.88%
Equity	7,082	30.12%
Total Debt	$23,513	100.00%

Source: MEHC 10-Q for 3/31/06

As Table 4 above shows, MEHC's capital structure is comprised of approximately 70% debt. The interest associated with this debt reduces PacifiCorp's income taxes that are paid to the taxing authorities.

Q. HAVE YOU CALCULATED THE IMPACT THAT THE ADDITIONAL MEHC DEBT WOULD HAVE ON PACIFICORP'S TAXES PAID?

A. Yes. Confidential Exhibit ICNU/217 shows a summary of the tax adjustment. As Confidential Exhibit ICNU/217 shows, the capital structure of MEHC produces additional debt and interest expense. As indicated in PacifiCorp's response to ICNU DR No. 10.2 (Confidential Exhibit ICNU/218), MEHC has a cost of long-term debt of [redacted].

This debt provides an additional interest expense which reduces PacifiCorp's taxes payable to governmental taxing authorities.

Recognizing the additional MEHC debt and additional interest expense reduces PacifiCorp's Oregon tax by $12.07 million and its revenue requirement by $19.45 million.

[redacted]

Q. DO YOU HAVE ANY COMMENTS TO MAKE ABOUT YOUR PROPOSED TAX ADJUSTMENT?

A. Yes. My proposed tax adjustment is dependent upon PacifiCorp's ratemaking capital structure. For purposes of this calculation, I utilized the capital structure as proposed by ICNU witness Mr. Gorman. In addition, I have utilized PacifiCorp's rate base as proposed in this case for calculating the additional interest expense that results in reducing PacifiCorp's income taxes paid and its revenue requirement.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/201

JAMES T. SELECKY QUALIFICATIONS

July 12, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. PLEASE STATE YOUR OCCUPATION.

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

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

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

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

In May of 1975, I transferred to the Rate and Revenue Requirement area of DECo. From that time, and until my departure from DECo in June 1984, I held various positions which included economic analyst, senior financial analyst, supervisor of the Rate Research Division, supervisor of the Cost-of-Service Division and director of the Revenue Requirement Department. In these positions, I was responsible for overseeing and performing economic and financial studies and book depreciation studies;

developing fixed charge rates and parameters and procedures used in economic studies; providing a financial analysis consulting service to all areas of DECo; developing and designing rate structure for electrical and steam service; analyzing profitability of various classes of service and recommending changes therein; determining fuel and purchased power adjustments; and all aspects of determining revenue requirements for ratemaking purposes.

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

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

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE A REGULATORY COMMISSION?

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

In addition, I have testified before the regulatory commissions of the States of Colorado, Connecticut, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Maryland, Massachusetts, Missouri, New Hampshire, New Jersey, North Carolina, Ohio, Oklahoma, Oregon, Tennessee, Texas, Utah, Washington, Wisconsin, and Wyoming, and the Provinces of Alberta, Nova Scotia and Saskatchewan. I also have testified before the Federal Energy Regulatory Commission. In addition, I have filed testimony in proceedings before the regulatory commissions in the States of Florida, Montana, New York, Oregon and Pennsylvania and the Province of British Columbia. My testimony has addressed revenue requirement issues, cost of service, rate design, financial integrity, accounting-related issues, merger-related issues, and performance standards. The revenue requirement testimony has addressed book depreciation rates, decommissioning expense, O&M expense levels, and rate base adjustments for items such as plant held for future use, working capital, and post test year adjustments. In addition, I have testified on deregulation issues such as stranded cost estimates and rate design.

Q. ARE YOU A REGISTERED PROFESSIONAL ENGINEER?

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/202

HEALTH CARE ADJUSTMENT

July 12, 2006

PACIFICORP - OREGON

Health Care Adjustment
(000)

Line	Description	Medical
1	Inflation Projection	9%
2	2007	$49,142
3	Adjusting for Employee Contribution	$45,095
4	2006 PacifiCorp Forecast	$50,303
5	Total Company Adjustment	$5,208
6	Oregon Allocation	28.442%
7	Oregon Adjustment	$1,481
8	Expense Factor	73.51%
9	Expense Adjustment	$1,089
10	Capital Portion	$392
11	Fixed Charge Rate	13.86%
12	Capital Revenue Requirement Impact	$54
13	Total Revenue Requirement Impact (Line 9 + Line 12)	$1,143

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/203

MOODY'S CREDIT MARKET TRENDS SERVICE

July 12, 2006

CREDIT MARKET TRENDS SERVICE

Bond yields and key indicators -- 6/29

MOODY'S DAILY LONG-TERM CORPORATE BOND YIELD AVERAGES

	Utilities	*Industrial*	*Corporate*
Aaa	NA*	5.98	5.98
Aa	6.26	6.15	6.21
A	6.51	6.48	6.50
Baa	6.75	7.06	6.91
Avg	6.51	6.42	6.47

MOODY'S DAILY TREASURY YIELD AVERAGES

Short-Term (3-5 yrs):	5.14
Medium-Term (5-10 yrs):	5.19
Long-Term (10+ yrs):	5.36

MOODY'S DAILY PUBLIC UTILITY COMMON STOCK YIELD AVERAGES

Price:	285.2
Yield:	3.72
New Dividend:	10.60

MOODY'S COMMODITY & SCRAP PRICE INDEXES

Spot Commodity Index:	2740.14
Industrial Metals Index:	1433.56

* Moody's "Aaa" Utilities Index was suspended on 12/10/01. Since 2000, TVA was the only issuer left in the index as a decade of deregulation, debt growth, competition, and consolidation eliminated the rest of

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/204

PACIFICORP SECOND SUPPLEMENTAL RESPONSE TO

OPUC STAFF DATA REQUEST NO. 154

July 12, 2006

OPUC Data Request 154

Using the format in Staff Data Request 35, please provide an analysis of PPL/802, Rosborough 1, inputting:

a. A 5.75% discount rate for CY 2006; salary increases of 3% for CYs 2006 and 2007, and Expected Rate of Return of 9.0% in CYs 2006 and 2007; and
b. A 5.75% discount rate for CY 2006, a 6.00% discount rate for CY 2007, salary increases of 3% for CYs 2006 and 200, and Expected Rate of Return of 9.0% in CYs 2006 and 2007.

2nd Supplemental Response to OPUC Data Request 154

Studies reflecting all requested assumptions – including 3% salary increases - are provided as 2nd Supplemental Attachment OPUC 154 on the enclosed CD. The first two tabs of the attachment respond to OPUC request 35; the remaining two tabs respond to OPUC request 154.

PacifiCorp Retirement Plan
Electric Operations

Reconciliation of Projected CY 2006 Expense from Actual CY 2005 and Projected CY 2007 from Projected CY 2006

(in millions)

Actual Calendar Year 2005 Expense	$49.9
Increase in interest cost due to additional benefit accruals during CY 2005	1.5
Impact of change in mortality table*	2.4
Impact of decrease in salary scale from 4% to 3%	(8.0)
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.0)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	6.1
Impact of change in expected return on assets assumption	(2.1)
Decrease in amortization payments due to payoff of transition obligation	(5.6)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	5.7
Projected Calendar Year 2006 Expense	$45.8
Increase in interest cost due to additional benefit accruals during CY 2006	0.6
Impact of change in discount rate	(4.2)
Increase in service cost due to demographics (e.g., new participants and increasing age of the population)	0.9
Impact on expected return on assets due to the expected change in the market related value of assets (before reflection of deferred asset losses)	(5.8)
Impact on expected return on assets due to scheduled recognition of a portion of the deferred asset losses	1.9
Decrease in amortization payments due to payoff of transition obligation	(0.1)
Increase in unrecognized net loss amortization due to scheduled recognition of a portion of the deferred asset losses	2.5
Decrease in unrecognized net loss amortization due to lower pay increases	(0.8)
Projected Calendar Year 2007 Expense	$40.8

* Change is necessary to stay within Hewitt Associates' Actuarial Assumption Guidelines

Projection Assumptions
- Discount rate: 5.75% for CY 2005, 5.75% for CY 2006, 6.00% for CY 2007
- Expected return on assets: 9.00% for all years
- Active participant increase of 119 during 2005, based on actual 2004 hires; constant thereafter
- Pay increases of 3%
- 8.75% rate of return on market value of assets during 2005 and 2006

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/205

PACIFICORP RESPONSE TO OPUC STAFF

DATA REQUEST NOS. 37 AND 272

July 12, 2006

UE-179/PacifiCorp
March 22, 2006
OPUC Data Request 37

OPUC Data Request 37

For fiscal years 2003 through 2006 (ending March 31), please provide the PacifiCorp contributions to the IBEW Local 57 Retirement Plan Trust.

Response to OPUC Data Request 37

FY 2003	$5.0 million
FY 2004	$5.644 million
FY 2005	$0
FY 2006	$1.048 million (approximate)

UE-179/PacifiCorp
April 26, 2006
OPUC Data Request 272

OPUC Data Request 272

As a follow-up to PacifiCorp's response to Staff Data Request No. 37, please provide the PacifiCorp contribution to the IBEW Local 57 Retirement Plan Trust for fiscal year 2002.

Response to OPUC Data Request 272

For 2002, there was no contribution made to the Local 57 Retirement Plan.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/206

PACIFICORP RESPONSE TO ICNU DATA REQUEST NO. 7.23

July 12, 2006

ICNU Data Request 7.23

Please identify all RTO development costs that are included in the test year as an expense, and identify the account in which those costs appear.

Response to ICNU Data Request 7.23

The requested information regarding RTO development costs are provided as Attachment ICNU 7.23 on the enclosed CD. This is the same attachment as provided earlier in data request OPUC 300 except that the FERC account number has been added as requested.

PACIFICORP
ATTACHMENT ICNU 7.23
UE-179 - RTO COSTS

Category	FERC Account	FY '05 Actual	Dec '07 Forecasted	Oregon Allocated
Bonus/Incentive	920	293	320	91
Other Salary/Labor Costs	920	3,596	3,929	
Salary Expense		**3,889**	**4,249**	**91**
Project Manager	922	490,357	535,761	152,381
Administration	922	169,069	184,724	52,539
Process Support	922	108,876	118,958	33,834
Finance Analyst	922	(5,832)	(6,372)	(1,812)
Director	922	692,432	756,547	215,177
Secondary Salary Expense		**1,454,902**	**1,589,618**	**452,118**
Oth Salary Overhd	920	(10,745)	(11,740)	(3,339)
Salary Overhead/Benefits		**(10,745)**	**(11,740)**	**(3,339)**
Total Labor Expense		**1,448,046**	**1,582,127**	**448,870**
Airfare	921	14,054	15,722	4,472
Lodging	921	7,420	8,301	2,361
Off-Site Facility Rentals	921	548	613	174
On-Site Meals & Refreshments	921	1,228	1,374	391
Meals & Entertainment	921	2,342	2,620	745
Vehicle Rental and Expense	921	225	252	72
Other Ground Transportation - Commercial	921	957	1,070	304
Auto Expense/Parking/Mileage	921	5,276	5,902	1,679
Cellular Telephones Expense	921	3,297	3,689	1,049
EE Telephones Expense	921	143	160	45
Training	921	3,286	3,676	1,045
Registration	921	6,148	6,878	1,956
Dues & Licenses	921	6,424	7,187	2,044
Books & Subscriptions	921	647	724	206
Other Employee Related Expenses	921	597	668	190
Computer Hardware	921	(21)	(23)	(7)
Office Supplies	921	182	204	58
Miscellaneous Materials & Supplies	921	276	309	88
Printing/Imaging/Mail Services	921	280	314	89
Mobile Messaging	921	1,496	1,674	476
Employee Expenses		**54,806**	**61,312**	**17,438**
Computer Hardware	935	415	464	132
Computer Software, Licenses	935	804	899	256
Tools	935	5	6	2
Miscellaneous Materials & Supplies	935	179	200	57
Building/Facilities Maint. Contracts	935	15	17	5
Materials & Supplies		**1,417**	**1,585**	**451**
Accounting & Tax Professional Services	923	3,181	3,559	1,012
Consulting/Technical Services	923	30,151	33,730	9,594
Engineering Services	923	(117,065)	(130,962)	(37,248)
Legal Fees & Services	923	598,790	669,873	190,525
Miscellaneous Contracts & Services	923	(2,518)	(2,817)	(801)
Primary Contracts & Servi		**512,540**	**573,384**	**163,081**
Club/Organization Membership/Expenses	930	346	387	110
Other		**346**	**387**	**110**
Total		**2,017,155**	**2,218,795**	**629,951**

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/207

GRID WEST NEWS RELEASE:

GRID WEST BOARD PLANS TO DISSOLVE

July 12, 2006

Grid West

NEWS RELEASE

Contact:
Bud Krogh, Grid West Facilitator – 206-464-1872

April 11, 2006

Grid West Board Plans to Dissolve;
Participants Look Ahead to New Activities

PORTLAND, Ore. – The Grid West Board of Directors voted today to prepare to dissolve the corporation. "We believe the Grid West proposal encompasses an outstanding operational and market design," said Chuck Durick, a Board member and President of Grid West. "The approach to governance is balanced and carefully thought out to fit the region. Still, the obstacles for successful implementation at this time have become too great. We need to recognize that and look for other ways to address the region's transmission issues constructively."

"We are deeply grateful to the many parties across the region – utilities, independent generators, state regulatory representatives, members of the renewables and environmental communities, tribes – who have been part of Grid West," said Bud Krogh, facilitator for Grid West over the past several years. "It is their steadfast support, and their generous contributions of time, personnel, and financial resources, that brought so many excellent ideas together in the Grid West process. I believe they will continue to serve the region well in the future."

Grid West was previously organized as a membership nonprofit corporation. In early November, 2005, Grid West was reorganized as a non-member non-profit corporation for transitional purposes. Grid West continued to hold dues paid by former members in anticipation of a possible return to membership status. As the Grid West organization winds up in the next several weeks, Grid West will refund in full all previously paid membership fees.

Said Cameron Lusztig, Director of Policy and Strategy at British Columbia Transmission Corporation and a Grid West Board member: "We are looking ahead. We hope to use many positive elements from the Grid West process to help us tackle the pressing issues for the region's transmission system. Whatever approach we take, the time to make real progress is here."

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/208

PACIFICORP RESPONSE TO OPUC STAFF DATA REQUEST NO. 283

July 12, 2006

OPUC Data Request 283

As a follow-up to Pacific's response to staff's DR No. 207(c), (a) please provide projected test period (CY 2007) incentive payments by employee group, including the number of affected employees in each group, in the same format as the information provided for the FY 2006 forecast of incentive payouts in Pacific's response to staff DR 207(b). (b) In addition, please provide the same information in the same format for actual FY 2005 incentive payments.

Response to OPUC Data Request 283

(a) The following is the response for projected test period (CY 2007) incentives by employee. This data was formulated by projecting 50% of maximum incentive opportunity (which represents target) from base pay, and factors in potential merit application to base of 3% for FY 2006 and CY2007.

Employee Group	Count	CY 2007 Incentive Estimate
Executive*	12	$ 934,228.39
SMG**	0	$ -
Active Non-SMG	2651	$ 29,756,946.97
Union	24	$ 101,210.72
Totals	2687	$ 30,792,386.08

*CEC no longer exists. Only Executives are reported.
**SMG classification no longer exists.

(b) FY 2005 Incentive total are also provided (below). Terminated and active employees are reported in each category as it is not readily possible to provide a breakdown from the reports on file for incentives paid in 2005/2006.

Employee Group	Count	Total 2005
Executive	2	$338,213.00
SMG*	105	$5,592,239.73
Non-SMG**	3022	$34,051,092.21
Union	32	$234,534.13

*SMG includes CEC from reporting completed in 2005
*Non-SMG: No breakdown in totals available to i.d. terminated from active

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/209

PACIFICORP RESPONSE TO OPUC STAFF DATA REQUEST NO. 297

July 12, 2006

OPUC Data Request 297

As a follow-up to Pacific's response to staff's Data Request (DR) No. 207(a), please provide the following:

(a) Details on the plan or plans available to officers and the senior management group (SMG) for 2005/2006 that are used as the basis for the UE 179 revenue requirement.

(b) A discussion of the bases for awarding incentives to the SMG during 2005/2006, clearly differentiating how incentives are awarded among groups within the SMG, if differences exist.

(c) A discussion of any known modifications to the SMG incentive plans that are planned for 2006/2007 and the CY 2007 test period.

Response to OPUC Data Request 297

(a) Senior Management Group (SMG) members will have their awards based on the full PacifiCorp Scorecard as well as the measures that follow:

20% PacifiCorp Scorecard
20% Business Unit Balanced Scorecard
60% Individual Performance*
* Including key behaviors tied to Customer Service and Safety

Corporate SMG with functions in the UK/US will have their awards based as follows:

20% ScottishPower Scorecard
20% Corporate Function Scorecard
60% Individual Performance*
* Including key behaviors tied to Customer Service and Safety

(b) See above.

(c) Details concerning changes that may occur to the Annual Incentive Program generally for 2006/2007 and CY 2007 test period are not yet known; however, it is known that the Senior Management Group (SMG) designation will no longer apply.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/210

PROPOSED INCENTIVE EXPENSE ADJUSTMENT

July 12, 2006

Proposed Incentive Expense Adjustment

Line		**Amount (000)**	**Disallowance Percent**	**Disallowance (000)**
1	Executive Incentives	$1,021	100%	$1,021
2	Non-Executive Incentives	$32,628	50%	$16,314
3	Total	$33,649		$17,335
4	Oregon Allocation			28.442%
5	Total Adjustment			$4,930
6	O&M Expense Adjustment			73.51%
7	O&M Expense			$3,624
8	Capital Portion			$1,306
9	Fixed Charge Rate			13.86%
10	Revenue Requirement			$181
11	Total Rev Req Impact			**$3,805**

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/211

PACIFICORP RESPONSE TO ICNU DATA REQUEST NO. 12.2

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

July 12, 2006

ICNU Data Request 12.2

For any reductions in manpower that have been announced since PacifiCorp has filed its rate case, please provide the number of announced reductions in manpower and the impact of those reductions on the test year revenue requirement.

Response to ICNU Data Request 12.2

Please see Confidential Attachments ICNU 12.2 -1 and 12.2 -2 on the enclosed CD.

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INFORMATION

OMITTED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/212

PACIFICORP RESPONSE TO ICNU DATA REQUEST NO. 15.5

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

July 12, 2006

UE-179/PacifiCorp
June 28, 2006
ICNU 15th Set Data Request 15.5

ICNU Data Request 15.5

ICNU's Data Request No. 12.2 asked for the number of announced reductions in manpower and the impact of those reductions on the test year revenue requirement for any reductions in manpower that have been announced since PacifiCorp has filed its rate case. If PacifiCorp has announced or decided on any additional changes in manpower since providing its response to ICNU Data Request No. 12.2, please provide the same information for those changes.

Response to ICNU Data Request 15.5

Please see Confidential Attachment ICNU 15.5 on the enclosed CD. This information is confidential and is provided subject to the terms and conditions of the protective order in this proceeding.

CONFIDENTIAL

INFORMATION

OMITTED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/213

PACIFICORP RESPONSE TO ICNU

DATA REQUEST NOS. 11.6 AND 11.7

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

July 12, 2006

ICNU Data Request 11.6

Regarding PacifiCorp's legal department, please provide the number of employees for each position for 2000-2005.

Response to ICNU Data Request 11.6

See Confidential Attachment ICNU 11.6 on the enclosed CD.

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INFORMATION

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ICNU Data Request 11.7

Regarding PacifiCorp's legal department, please provide the expected number of employees for each position for 2006-2010.

Response to ICNU Data Request 11.7

See Confidential Attachment ICNU 11.7 on the enclosed CD. Over time and as appropriate, the company will be looking for opportunities to bring capable counsel internal to PacifiCorp and reduce its reliance on external counsel. However, it is not expected that PacifiCorp will ever rely solely on internal counsel and it is not expected that overall legal costs will be materially different in the test period as compared to historic levels.

CONFIDENTIAL

INFORMATION

OMITTED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/214

PACIFICORP RESPONSE TO ICNU DATA REQUEST NO. 11.8

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

July 12, 2006

ICNU Data Request 11.8

Please identify the total legal department costs for 2000-05, and expected legal department costs for 2006-10. Please provide a categorical breakdown and description of PacifiCorp's legal department costs.

Response to ICNU Data Request 11.8

Please see Confidential Attachment ICNU 11.8 on the enclosed CD. Over time and as appropriate, the company will be looking for opportunities to bring capable counsel internal to PacifiCorp and reduce its reliance on external counsel. However, it is not expected that PacifiCorp will ever rely solely on internal counsel and it is not expected that overall legal costs will be materially different in the test period as compared to historic levels. At this time, PacifiCorp does not expect any material changes from the FY 2006 levels in the expected legal department costs for the 2006 to 2010 period absent a significant change in the level of regulatory activity in its state and federal jurisdictions.

CONFIDENTIAL

INFORMATION

OMITTED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/215

PACIFICORP RESPONSE TO ICNU DATA REQUEST NO. 13.6

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

July 12, 2006

ICNU Data Request 13.6

In response to ICNU Data Request No. 11.8, PacifiCorp provided total legal department costs. The confidential data that was provided indicates a decline in the expense totals from FY 2005 to FY 2006.

a. Please provide the legal expenses that are included in the revenue requirement for the historic test year.

b. Please provide the legal expenses that are included in the forecast test year revenue requirement on a total Company basis and a jurisdictional basis.

c. Has the decline in the legal expenses in 2006 from 2005 been reflected in the development of the revenue requirement? If not, please explain.

Response to ICNU Data Request 13.6

a. See Confidential Attachment ICNU 13.6 on the enclosed CD.

b. See Confidential Attachment ICNU 13.6 on the enclosed CD.

c. See Confidential Attachment ICNU 13.6 on the enclosed CD.

CONFIDENTIAL

INFORMATION

OMITTED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/216

PACIFICORP RESPONSE TO ICNU DATA REQUEST NO. 15.6

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

July 12, 2006

UE-179/PacifiCorp
June 28, 2006
ICNU 15th Set Data Request 15.6

ICNU Data Request 15.6

In response to ICNU Data Request No. 11.8, PacifiCorp provided legal department expenses for FY 2004 through 2006.

a. Please provide the level of outside legal expense that is included in its historic year.
b. Please provide the level of outside legal expense that is included in its forecast year, along with any costs for outside legal activities that it excluded.
c. Please provide its actual FY 2006 outside legal expense that compares with the amounts provided in (b.) above.

Response to ICNU Data Request 15.6

Please see Confidential Attachment ICNU 15.6 on the enclosed CD. This information is confidential and is provided subject to the terms and conditions of the protective order in this proceeding.

CONFIDENTIAL

INFORMATION

OMITTED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/217

CONSOLIDATED TAX ADJUSTMENT

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

July 12, 2006

CONFIDENTIAL

INFORMATION

OMITTED

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 179

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

ICNU/218

PACIFICORP RESPONSE TO ICNU DATA REQUEST NO. 10.2

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

July 12, 2006

ICNU Data Request 10.2

Please provide the MEHC capital structure and cost of debt for the test year.

Response to ICNU Data Request 10.2

Please see Confidential Attachment ICNU 10.3 on the enclosed CD for the requested information.

CONFIDENTIAL

INFORMATION

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Davison Van Cleve PC
Attorneys at Law
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Suite 400
333 S.W. Taylor
Portland, OR 97204

July 12, 2006

Via Electronic and U.S. Mail

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

Re: In the Matter of PACIFIC POWER & LIGHT Request for a General Rate Increase in the Company's Oregon Annual Revenues
Docket No. UE 179

Dear Filing Center:

Enclosed for filing in the above-referenced docket please find an original and five copies of each of the following:

- Direct Testimony of Randall Falkenberg on Non-Power Cost Issues on behalf of the Industrial Customers of Northwest Utilities (ICNU/116-120);

- Redacted Direct Testimony of James Selecky on behalf of the Industrial Customers of Northwest Utilities (ICNU/200-218);

- Direct Testimony of Kathryn Iverson on behalf of the Industrial Customers of Northwest Utilities (ICNU/300-305); and

- Direct Testimony of Michael Gorman on behalf of the Citizens' Utility Board and the Industrial Customers of Northwest Utilities (CUB-ICNU/400-418).

The confidential pages of ICNU/200, ICNU/211-218, and CUB-ICNU/415 are provided in separate, sealed envelopes pursuant to the terms of the Protective Order in this proceeding.

Thank you for your assistance.

Sincerely,

/s/ Christian Griffen
Christian W. Griffen

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Direct Testimony of Randall Falkenberg on Non-Power Costs Issues, Direct Testimony of James Selecky, Direct Testimony of Kathryn Iverson, and Direct Testimony of Michael Gorman upon the parties on the service list by causing the same to be deposited in the U.S. Mail, postage-prepaid.

Dated at Portland, Oregon, this 12th day of July, 2006.

<u>/s/ Christian Griffen</u>
Christian W. Griffen

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DEPARTMENT OF JUSTICE JASON W JONES ASSISTANT ATTORNEY GENERAL REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 jason.w.jones@state.or.us	**DEPARTMENT OF JUSTICE** MICHAEL T WEIRICH ASSISTANT ATTORNEY GENERAL REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 michael.weirich@doj.state.or.us

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