June 27, 2005

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OREGON PUBLIC UTILITY COMMISSION
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RE: **Docket No. UE 170** - In the Matter of PACIFIC POWER & LIGHT (dba PacifiCorp) Request for a General Rate Increase in the Company's Oregon Annual Revenues

Enclosed for filing in the above-captioned docket is the Public Utility Commission Staff's Surrebuttal Testimony. This document is being filed by electronic mail with the PUC Filing Center.

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PUBLIC UTILITY COMMISSION OF OREGON

UE 170

STAFF SURREBUTTAL TESTIMONY OF

Maury Galbraith
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Michael Dougherty
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In the Matter of
PACIFIC POWER & LIGHT (dba PacifiCorp)
Request for a General Rate Increase in the Company's Oregon Annual Revenues

Redacted Version

June 27, 2005

CASE: UE 170
WITNESS: Maury Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Surrebuttal Testimony

June 27, 2005

Q. PLEASE STATE YOUR NAME.

A. My name is Maury Galbraith.

Q. DID YOU PREVIOUSLY FILE TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was filed as Exhibit Staff/600. My Witness Qualification Statement is found in Exhibit Staff/601.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to respond to the Industrial Customers of Northwest Utilities (ICNU) and the Citizens' Utility Board (CUB) testimony regarding PacifiCorp's proposed Transition Adjustment mechanism. I also address PacifiCorp's rebuttal of the ICNU and CUB testimony.

Q. PLEASE SUMMARIZE ICNU'S TESTIMONY REGARDING PACIFICORP'S PROPOSED TRANSITION ADJUSTMENT MECHANISM.

A. ICNU asserts that there are four problems with PacifiCorp's proposed Transition Adjustment mechanism:

1. That the graveyard hour market liquidity cap used in PacifiCorp's GRID model results in a situation where the value of the energy freed up by direct access will always be lower than the market price paid by an ESS to serve a direct access customer; and therefore it is impossible for a customer to benefit by switching to direct access. See ICNU/100 Falkenberg/48-53.
2. That PacifiCorp's GRID model does little to simulate transmission costs and therefore does not accurately asses the impact of direct access participation on the company's operations. See ICNU/100 Falkenberg/53.

3. That PacifiCorp's GRID model does not have the capability to simulate changes in long-term planning associated with direct access participation and therefore is a questionable tool to use for determining the company's transition adjustment. See ICNU/100 Falkenberg/53-55.
4. That PacifiCorp's proposed annual update of the net variable power cost (NVPC) component of cost-of-service rates is an unnecessary regulatory complication that ratepayers can do without. See ICNU/100 Falkenberg/56-58.

Q. PLEASE SUMMARIZE CUB'S TESTIMONY REGARDING PACIFICORP'S PROPOSED TRANSITION ADJUSTMENT MECHANISM.

A. CUB asserts that PacifiCorp's proposed Transition Adjustment mechanism unfairly impacts PacifiCorp's residential customers (CUB/100, Jenks/19-22 and Jenks/30) and lists seven specific problems with PacifiCorp's proposal to annually update the NVPC component of cost-of-service rates. The seven problems are:

1. That the accelerated schedule and update process built into PacifiCorp's proposed Transition Adjustment mechanism make it difficult to conduct prudence reviews. See CUB/100 Jenks/23-24.
2. That PacifiCorp's proposed Transition Adjustment mechanism would create a mismatch between the fixed and variable costs included in cost-of-service rates. See CUB/100 Jenks/24.

3. That PacifiCorp's proposed Transition Adjustment mechanism would create a mismatch between the state allocation factors used to calculate cost-of-service rates. See CUB/100 Jenks/24-25.
4. That PacifiCorp's proposed Transition Adjustment mechanism would create an opportunity for PacifiCorp to "game" the regulatory system. More specifically, CUB indicates that the forward market prices used in PacifiCorp's GRID model should be independently verifiable. See CUB/100 Jenks/26.
5. That PacifiCorp's proposed Transition Adjustment mechanism would shift the risk of Utah load growth to Oregon customers. See CUB/100 Jenks/26-27.
6. That PacifiCorp's proposal to exclude new generation resources that have not previously been reviewed in a general rate case from the GRID model results in higher "phantom costs" being included in cost-of-service rates. See CUB/100 Jenks/27-29.
7. That the regulatory burden associated with PacifiCorp's proposal is too great. See CUB/100 Jenks/29.

<u>Staff Response to ICNU's Testimony</u>

<u>1. Market Liquidity Cap during Graveyard Hours (1:00 AM to 5:00 AM).</u>

Q. PLEASE RECAP ICNU'S ARGUMENT RELATED TO THE MARKET LIQUIDITY CAPS USED IN PACIFICORP'S GRID MODEL.

A. ICNU argues that PacifiCorp's transition adjustment is flawed because the GRID model contains market liquidity caps that limit energy sales during graveyard hours. With the limit on wholesale sales during graveyard hours, the GRID model indicates that PacifiCorp's operational response to direct access participation during these hours is to decrease thermal generation. By including the variable cost of coal-fired generation in the calculation of the weighted-average value of freed-up energy, ICNU argues the PacifiCorp's transition adjustment will always produce a value of freed-up energy that is lower than the price paid by an ESS to serve a direct access customer. ICNU argues that this situation makes it impossible for an ESS to attract direct access customers. (See ICNU/100, Falkenberg/48-52.)

Q. DID THE PARTIAL STIPULATION BETWEEN PACIFICORP, STAFF, CUB, ICNU, AND FRED MEYER STORES RESOLVE THIS ISSUE?

A. Yes. As I indicated in my direct testimony, Paragraph 5(n) of the Partial Stipulation would increase the GRID model wholesale market liquidity caps for the Mid-Columbia and California-Oregon Border market hubs during graveyard hours for the purpose of calculating the transition adjustments.

Q. ICNU ARGUES THAT THE PARTIAL STIPULATION PROVIDES A "PARTIAL SOLUTION," AND MAY NOT "COMPLETELY ELIMINATE" THIS PROBLEM. (ICNU/100, FALKENBERG/52 LINES 16-20). DO YOU AGREE WITH THIS ASSESSMENT?

A. No. Paragraph 5(n) of the Partial Stipulation represents a complete and final resolution of the graveyard hour market cap issue.

Q. ICNU ARGUES THAT PACIFICORP MUST DEMONSTRATE THAT THE SOLUTION CONTAINED IN THE PARTIAL STIPULATION PROVIDES A "TRUE MARKET EVEN RESULT" BEFORE THE COMMISSION CAN RESOLVE THIS ISSUE. (ICNU/100, FALKENBERG/53 LINES 6-8.) DO YOU AGREE WITH THIS ASSERTION?

A. No. Although the parties who signed the Partial Stipulation agreed that the graveyard hour market cap issue is no longer a reason to oppose PacifiCorp's transition adjustment, the parties are free to debate whether the agreed-to calculations produce an overall result that is reasonable. ICNU recommends that the Commission test this overall result using a re-defined "market-minus" standard.[1] ICNU recommends that, at a minimum, the Commission require the Partial Stipulation calculations to produce a value of freed-up energy that is always greater than or equal to the price of a standard market purchase. In other words, ICNU proposes that the Commission judge alternative transition adjustment mechanisms against a standard that would guarantee an ESS the ability to meet or beat PacifiCorp's cost-of-service rate. Staff does not support ICNU's proposed minimum standard because it fails to further the purpose of a transition adjustment mechanism.

Q. HAS STAFF DISCUSSED THE PURPOSE OF A TRANSITION ADJUSTMENT MECHANISM AND THE STANDARDS BY WHICH TO JUDGE THESE MECHANISMS IN PREVIOUS TESTIMONY IN THIS DOCKET?

[1] PacifiCorp witness Widmer accurately indicates that ICNU has re-defined the meaning of "market-even" from the definition used in Docket UM 1081. (PPL/609, Widmer/5, Lines 5-10).

A. Yes. In my direct testimony I indicated that the purpose of a Transition Adjustment is two-fold: (1) to accurately measure the direction and magnitude of any cost shift (i.e., the impact of direct access); and (2) to indicate the level of transition charges or transition credits that might reasonable balance the interests of retail electricity consumers and utility investors. (Staff/600, Galbraith/1.) I also addressed these issues in direct testimony in Docket UM 1081.

<u>2. Simulation of Transmission Costs in PacifiCorp's GRID Model.</u>

Q. PLEASE RECAP ICNU'S ARGUMENT RELATED TO THE MODELING OF TRANSMISSION COSTS IN PACIFICORP'S GRID MODEL.

A. ICNU argues that GRID does little to simulate transmission costs and therefore does not accurately account for the impact of direct access load leaving the system on PacifiCorp's transmission costs.

Q. HOW DOES PACIFICORP ACCOUNT FOR TRANSMISSION COSTS IN ITS GRID MODEL?

A. Expenses associated with the company's wheeling contracts are direct inputs into the GRID model. Expenses associated with additional day-ahead firm wheeling are developed by the company's Commercial and Trading Department. (PPL/600, Widmer/15.)

Q. DOES PACIFICORP'S GRID MODEL HAVE THE CAPABILITY TO REFLECT THE IMPACT OF DIRECT ACCESS ON THE COMPANY'S TRANSMISSION COSTS?

A. Yes.

Q. DOES ICNU IDENTIFY SPECIFIC TRANSMISSION CONTRACTS OR COSTS INCLUDED IN PACIFICORP'S GRID RUNS THAT WOULD BE AVOIDED WITH DIRECT ACCESS PARTICIPATION?

A. No.

Q. DOES ICNU'S TRANSMISSION MODELING ISSUE REPRESENT A FATAL FLAW IN PACIFICORP'S PROPOSED TRANSITION ADJUSTMENT MECHANISM?

A. No.

<u>3. Simulation of PacifiCorp's Long-Term Response to Direct Access.</u>

Q. PLEASE RECAP ICNU'S ARGUMENT RELATED TO THE MODELING OF PACIFICORP'S LONG-TERM RESPONSE TO DIRECT ACCESS.

A. ICNU argues that the GRID model does not have the capability to simulate changes in long-term planning associated with direct access participation and therefore is the wrong tool to use for determining PacifiCorp's transition adjustment.

Q. WHAT IS THE PRIMARY FORUM FOR ADDRESSING PACIFICORP'S LONG-TERM RESPONSE TO DIRECT ACCESS?

A. The primary forum for addressing PacifiCorp's long-term response to direct access is PacifiCorp's Integrated Resource Plan (IRP). PacifiCorp's 2004 IRP is currently being considered in Docket No. LC 39.

Q. DOES PACIFICORP, IN ITS 2004 IRP, REDUCE ITS LONG-TERM FORECAST OF OREGON LOAD FOR DIRECT ACCESS PARTICIPATION?

A. No. (See PacifiCorp's 2004 IRP, Chapter 3 – Resource Needs Assessment, pp. 45-46.)

Q. DOES PACIFICORP, IN ITS 2004 IRP, PERFORM SCENARIO RISK ANALYSIS TO INVESTIGATE THE POTENTIAL IMPACT OF DIRECT ACCESS PARTICIPATION ON ITS LONG-TERM RESOURCE NEEDS?

A. No. (See PacifiCorp's 2004 IRP, Chapter 8 – Results, pp. 155-161.)

Q. DOES PACIFICORP, IN ITS 2004 IRP, DISCUSS THE POTENTIAL IMPACT OF INCREASED DIRECT ACCESS PARTICIPATION ON ITS LONG-TERM PLANNING?

A. Yes. In its Action Plan, PacifiCorp states:

> Material shifts in either loads or resources could affect the timing and size of major resource additions. Examples of significant changes that could occur include a large loss of load under retail competition (OR SB1149)…
>
> Possible paths PacifiCorp could take if a major shift in either loads or resources would occur include:
>
> - Delay or accelerate resource procurement(s)
> - Reassess the amount and timing of the need
>
> (See PacifiCorp's 2004 IRP, Chapter 9 – Action Plan, p. 190.)

Q. HAS ICNU PROVIDED COMMENTS IN DOCKET NO. LC 39 RELATED TO PACIFICORP'S LONG-TERM PLANNING FOR DIRECT ACCESS?

A. No, not yet. PacifiCorp's 2004 IRP was filed with the Commission on January 20, 2005. Parties to Docket LC 39 were to submit comments on PacifiCorp's

IRP by May 23, 2005. ICNU was not among the five parties who submitted comments. Parties will have an opportunity to reply to staff's comments by July 13, 2005, and to staff's final recommendations and proposed order on or before Aug. 1, 2005.

Q. DOES STAFF SUPPORT PACIFICORP'S APPROACH TO ACCOUNTING FOR OREGON DIRECT ACCESS PARTICIPATION IN ITS IRP?

A. Yes. Given the low level of direct access participation in PacifiCorp's service territory to date and the ability for customers to return to cost-of-service rates on an annual basis, Staff believes it is reasonable at this time for PacifiCorp to plan to serve the entire forecasted load in its Oregon service territory on a long-term basis.

Q. DOES PACIFICORP ADDRESS THIS ICNU ISSUE IN ITS REBUTTAL TESTIMONY?

A. Yes. PacifiCorp witness Widmer concludes:

> The real issue is whether or not the Company should plan for Direct Access before we have any idea of what the participation level will be. At this time, the Company does not know how many customers will elect Direct Access and leave our system, how long it will be before they return, or if they will ever return, because customers have the sole discretion to return or not return at the end of each annual Direct Access cycle. (PPL/609, Widmer/8-9.)

Q. DOES THE COMBINATION OF A REQUIRED COST-OF-SERVICE RATE OPTION (ORS 757.603) AND A REQUIRED ANNUAL ELECTION WINDOW (ORS 757.609) DICTATE A SHORT-TERM OPERATIONAL PERSPECTIVE WHEN CALCULATING AN ANNUAL TRANSITION ADJUSTMENT?

A. Yes, to a large extent. Longer-term opt-out options would allow for a longer-term perspective. However, Portland General Electric's three- and five-year opt-out options have generated limited customer interest. A binding permanent opt-out has not yet been developed.

Q. DOES ICNU OFFER A "PREFERRED SOLUTION" TO THIS PROBLEM?

A. Yes. ICNU witness Falkenberg states:

> A much less complex solution is to simply recognize that when the system is appropriately planned, departure of direct access load will result in a net reduction in purchases. Thus the value of freed up resources should simply reflect the cost of a standard market product with additional transmission costs avoided. (ICNU/100, Falkenberg/55, Lines 12-16.)

Q. IS ICNU'S PREFERRED SOLUTION REASONABLE?

A. No. ICNU's "market-plus" solution is predicated on a poorly stated view that PacifiCorp should not plan to serve a portion of its direct access eligible load. PacifiCorp's proposed Transition Adjustment, with the modifications provided by the Partial Stipulation, is fully consistent with the Company's 2004 IRP. At this time, it is reasonable for the Company to plan to serve the entire forecasted load in its Oregon service territory on both an annual and long-term basis. These assumptions may change if PacifiCorp sees more interest in direct access.

<u>4. Annual Update of NVPC Component of Cost-of-Service Rates.</u>

Q. PLEASE RECAP ICNU'S ARGUMENT RELATED TO THE ANNUAL UPDATE OF THE NVPC COMPONENT OF COST-OF-SERVICE RATES.

A. In general, ICNU argues that the annual update of cost-of-service rates is an unnecessary regulatory complication. Mr. Falkenberg states:

> Given that there are apparently only a handful of current direct access customers, it seems rather unnecessary to require all customers have the power rates change every year to avoid a hypothetical subsidy to a few customers. (ICNU/100, Falkenberg/57, Lines 21-24.)

More specifically, ICNU argues that an annual power cost update would: (1) result in ratepayers absorbing a substantial portion of PacifiCorp's power cost risk; (2) be fraught with problems related to GRID modeling, including the scope of included costs, modeling methods, and update procedures; and (3) that only a full rate case, and not an abbreviated rate case, provides the time and process necessary for a complete review of all power cost issues.

Q. DOES AN ANNUAL UPDATE OF THE NVPC COMPONENT OF COST-OF-SERVICE RATES SHIFT POWER COST RISK FROM SHAREHOLDERS TO RATEPAYERS?

A. Yes. An annual NVPC update exposes ratepayers to a change in normalized power costs on a single day each year. Ratepayers would be primarily exposed to electricity and natural gas market price risk. Ratepayer exposure to thermal generating unit outage risk and hydroelectric streamflow risk would be minimal since these variables are normalized for ratemaking purposes. In comparison, without an annual NVPC update, the frequency of ratepayer exposure to changes in normalized power costs would coincide with the frequency of rate case decisions. Importantly, PacifiCorp's shareholders would remain exposed to deviations between actual power costs and normalized power costs included in cost-of-service rates.

Q. DO YOU CONSIDER THE SHIFT IN POWER COST RISK FROM SHAREHOLDERS TO RATEPAYERS TO BE SUBSTANTIAL?

A. The shift in risk that would be caused by an annual update of the NVPC component of cost-of-service rates is not so great that it should be avoided at all cost.

Q. WOULD AN ANNUAL UPDATE OF THE NVPC COMPONENT OF PACIFICORP'S COST-OF-SERVICE RATES BE FRAUGHT WITH PROBLEMS RELATED TO GRID MODELING?

A. No. The scope of the included costs and update procedures are well defined. (PPL/700, Omohundro/10-12.)

Q. AS AN EXAMPLE OF THE TYPE OF PROBLEM THAT CAN ARISE WITH MODEL UPDATES, MR. FALKENBERG POINTS TO A RECENT CONTROVERSY IN PORTLAND GENERAL ELECTRIC'S (PGE'S) ANNUAL RESOURCE VALUATION MECHANISM (RVM). (ICNU/100, FALKENBERG/57, LINES 4-10.) HAS MR. FALKENBERG ACCURATELY PORTRAYED THIS EVENT?

A. No. Mr. Falkenberg suggests that the close timing between the contract updates and the direct access election window, created a situation where there was "no avenue" for the parties to address the ratemaking treatment of PGE's capacity tolling contracts. In fact, there were at least two procedural avenues available to the parties: (1) ask the Commission to delay the direct access election window; and (2) ask the Commission to defer the costs and benefits related to these contracts for later ratemaking treatment. Both of these avenues would have provided an opportunity for a contested resolution of the conflict. In fact, as indicated in Administrative Law Judge Kirkpatrick's Prehearing Conference Memorandum, the parties to PGE's 2005 RVM agreed to a resolution. (ICNU/108, Falkenberg/8).

Q. DO YOU AGREE WITH ICNU'S ASSERTION THAT PGE'S MONET MODEL WAS MORE MATURE AND BETTER-UNDERSTOOD IN 2001, THAN PACIFICORP'S GRID MODEL IS IN 2005? (ICNU/100, FALKENBERG/57, LINES 11-14.)

A. No. The GRID model has been thoroughly reviewed in Docket Nos. UE 134, UE 147, and UE 170.

Q. DOES AN ANNUAL UPDATE OF THE NVPC COMPONENT OF COST-OF-SERVICE RATES (I.E., AN ABBREVIATED RATE CASE) PROVIDE THE TIME AND PROCESS NECESSARY FOR A COMPLETE REVIEW OF ALL POWER COST ISSUES?

A. Yes. This has been demonstrated in PGE's annual RVM process.

Q. ARE ANY OF ICNU'S FOUR PROBLEMS WITH PACIFICORP'S TRANSITION ADJUSTMENT MECHANISM WELL FOUNDED?

A. No.

Staff Response to CUB's Testimony

Q. PLEASE RECAP CUB'S OVERARCHING ARGUMENT RELATED TO THE IMPACT OF PACIFICORP'S PROPOSED TRANSITION ADJUSTMENT MECHANISM ON RESIDENTIAL CUSTOMERS.

A. CUB begins its argument by identifying two principles underlying Oregon's direct access program: (1) that customers who go to the market retain the stranded cost or benefits associated with a utility's generation assets; and (2) that direct access should not impact customer classes that are not eligible for direct access. (CUB/100, Jenks/19, Lines 9-13.) CUB then provides theoretical discussions of: (1) the valuation of stranded costs and benefits; and (2) the timing of the direct access enrollment window. (CUB/100, Jenks/20-21.) CUB then concludes that PacifiCorp's Transition Adjustment mechanism has nothing to do with residential customers. (CUB/100, Jenks/22, Lines 1-2.) CUB then lists, and proceeds to discuss, seven problems with PacifiCorp's proposed Transition Adjustment mechanism. (CUB/100, Jenks/22-30.) Finally, based on a finding that for residential customers the harms of PacifiCorp's proposal outweigh the benefits, CUB recommends that the Commission reject PacifiCorp's proposal to include customer classes that are not eligible for direct access in the Transition Adjustment. (CUB/100, Jenks/30, Lines 8-16.)

Q. IS CUB'S CONCLUSION THAT PACIFICORP'S TRANSITION ADJUSTMENT MECHANISM HAS NOTHING TO DO WITH RESIDENTIAL CUSTOMERS ACCURATE?

A. No. CUB's colorful question and answer on this point intentionally exaggerates the lack of a relationship between PacifiCorp's Transition Adjustment and its residential customers. (CUB/100, Jenks/22, Lines 1-2.) ORS 757.607(1) explicitly states that the provision of direct access must not cause the unwarranted shifting of costs to other retail electricity consumers. I think the point that Mr. Jenks is ultimately trying to make is that in protecting PacifiCorp's cost-of-service customers from unwarranted cost shifts, PacifiCorp's proposed Transition Adjustment, with its annual update of the NVPC component of cost-of-service rates, would do more harm than good.

Q. DID PACIFICORP ADDRESS CUB'S OVERARCHING CONCERN REGARDING THE IMPACT ON RESIDENTAIL CUSTOMERS IN ITS REBUTTAL TESTIMONY?

A. Yes. PacifiCorp witness Omohundro emphasized the company's goal to make the annual Transition Adjustment as streamlined and straightforward as possible. Ms. Omohundro indicated that: (1) to update NVPC for only a subset of PacifiCorp's customers would create complexity (PPL/701, Omonhundro/2-3); and (2) the company avoided the complexities associated with an unfamiliar mechanism and process by proposing a mechanism that mirrors the schedule and framework of PGE's annual RVM (PPL/701, Omohundro/3.)

Q. DOES PACIFICORP'S PROPOSED TRANSITION ADJUSTMENT MECHANISM MIRROR THE PROCESS AND FRAMEWORK OF PGE'S ANNUAL RVM?

A. Yes and no. PacifiCorp's proposed transition adjustment mechanism mirrors the process, but not the framework, of PGE's annual RVM. PacifiCorp's proposed transition adjustment mechanism is based on an impact analysis of direct access participation on the company's operations, costs, and revenues. PGE's RVM is based on a mark-to-market analysis of the company's long-term and short-term resources.

Q. WHY SHOULD THE COMMISSION UPDATE THE NVPC COMPONENT OF PACIFICORP'S COST-OF-SERVICE RATES AT THE SAME TIME IT SETS PACIFICORP'S ANNUAL TRANSITION ADJUSTMENT RATES?

A. By simultaneously setting PacifiCorp's cost-of-service energy rates and transition adjustment rates the Commission can shield both PacifiCorp's cost-of-service customers and PacifiCorp's shareholders from unwarranted cost shifts.

PacifiCorp's cost-of-service energy rates should be based on projected NVPC given the assumption of no direct access participation. This ratemaking shields PacifiCorp's cost-of-service customers from direct access cost shifts.

PacifiCorp's transition adjustment rates should be set based on the impact of direct access on PacifiCorp's costs and revenues (i.e., the difference between the projected NVPC given no direct access participation and the projected NVPC given expected direct access participation). This ratemaking allows PacifiCorp to fund its transition payments to direct access participants through the savings achieved from rebalancing its system.

Importantly, this combined ratemaking does not provide incentive to direct access eligible customers on their choice to go direct access or remain with the company.

Q. WOULD UPDATING THE NVPC COMPONENT OF PACIFICORP'S COST-OF-SERVICE RATES FOR ONLY DIRECT ACCESS ELIGIBLE CUSTOMERS ADD COMPLEXITY TO THE RATEMAKING PROCESS?

A. Yes. This alternative would be difficult to implement and would result in two sets of cost-of-service rates, one for direct access eligible customers, and one for non-direct access eligible customers.

Q. IS LIMITING THE ANNUAL NVPC UPDATE TO DIRECT ACCESS ELIGIBLE CUSTOMERS A REASONABLE ALTERNATIVE?

A. No. Once stakeholders and the Commission have gone to the trouble of reviewing the prudence and reasonableness of the company's projected NVPC it makes sense to update the cost-of-service rates for all customers, not just those eligible for direct access.

1. Higher "Phantom" Costs Included in Rates.

Q. PLEASE RECAP CUB'S ARGUMENT RELATED TO INCLUDING "PHANTOM" COSTS IN RATES.

A. CUB argues that PacifiCorp's proposal to exclude new generating plants and improvements to existing plants from its GRID model projections until the capital investments have been reviewed in a general rate case would result in customers being charged an NVPC that is higher than the NVPC the company is likely to incur. CUB questions whether substituting spot market purchases for a not-yet-in-ratebase plant accurately represents the resource alternative the company would have chosen but for the new plant. By failing to include its actual resources, or alternatively its ‘but for’ resources, in its annual GRID modeling the company is including “phantom” costs in rates. (CUB/100, Jenks/27-29.)

Q. DID PACIFICORP ADDRESS CUB’S CONCERN REGARDING “PHATOM” COSTS IN ITS REBUTTAL TESTIMONY?

A. Yes. Ms. Omohundro responded that:

> ORS 757.355 prohibits the inclusion of new resources in rates, unless they are in-service prior to the beginning of the rate effective period, because they are not used and useful. Consequently, in the past the Public Utility Commission of Oregon has adopted an approach whereby the new resource is excluded from rates until it is used and useful and in the interim it is assumed that load will be served through system balancing transactions. (PPL/701, Omohundro/8, Lines 3-8.)

Q. WHAT IS STAFF’S POSITION ON THIS ISSUE?

A. Staff recommends that all improvements to existing resources be included in the company’s annual GRID modeling. In addition, staff recommends that new resources that are in-service prior to the beginning of the rate effective period be included in the company’s annual GRID modeling. These recommendations will improve the realism, and hence the accuracy, of PacifiCorp’s GRID modeling. In addition, it provides incentive for the company to file a rate case to include the fixed costs of these resources in rates.

2. <u>Difficult to Conduct Prudence Reviews; Opportunity for PacifiCorp to Game the Regulatory System; and Unnecessary Regulatory Burden.</u>

Q. PLEASE RECAP CUB'S ARGUMENT RELATED TO PRUDENCE REVIEWS.

A. CUB argues that the accelerated schedule and GRID update procedures associated with PacifiCorp's proposed Transition Adjustment make it difficult to conduct prudence reviews. (CUB/100, Jenks/23-24.)

Q. DOES AN ACCELERATED SCHEDULE WITH GRID UPDATES MAKE IT MORE DIFFICULT TO CONDUCT PRUDENCE REVIEWS?

A. Yes, when compared to the timeframe and update procedures associated with a general rate case filing. However, as I indicated earlier in response to ICNU's testimony, PacifiCorp's proposed Transition Adjustment mechanism does provide the time and process necessary for a complete review of all power cost issues.

Q. PLEASE RECAP CUB'S ARGUMENT RELATED TO ELIMINATING OPPORTUNITIES TO GAME THE REGULATORY SYSTEM.

A. CUB argues that regulatory mechanisms should be independently verifiable and not subject to gaming. Specifically, CUB indicates that the forward price curves used in the company's GRID model should accurately reflect forward market prices and suggests that company-produced forward curves could be subject to manipulation. To ensure that gaming does not happen, CUB recommends that the forward price curves used in the GRID model be obtained from an independent source. (CUB/100, Jenks/26.)

Q. DID CUB CHALLENGE THE USE OF PACIFICORP-PRODUCED FORWARD PRICE CURVES IN THE REVENUE REQUIREMENT PORTION OF THIS RATE CASE?

A. No.

Q. COULD CUB RAISE THIS FORWARD PRICE CURVE ISSUE IN AN ANNUAL TRANSITION ADJUSTMENT PROCEEDING?

A. Yes.

Q. DOES CUB'S FORWARD PRICE CURVE ISSUE REPRESENT A FATAL FLAW IN PACIFICORP'S PROPOSED TRANSITION ADJUSTMENT MECHANISM?

A. No.

Q. DID PACIFICORP RESPOND TO CUB'S REGULATORY BURDEN ARGUMENT ITS REBUTTAL TESTIMONY?

A. Yes. Ms. Omohundro responded that:

> SB 1149 resulted in an increased regulatory burden on all electric utilities in the state of Oregon, as well as all intervening parties. The transition adjustment requires an accurate determination of the value of a slice of an electric utility's system. This is a difficult and complex task that inevitably results in a time consuming, controversial and resource intensive process for all parties involved. (PPL/701, Omohundro/7, Lines 14-18.)

Q. DO YOU AGREE WITH MS. OMOHUNDRO'S ASSESSMENT OF THIS ISSUE?

A. Yes.

3. Mismatch Between the Fixed and Variable Costs Included in Rates; Mismatch Between State Allocation Factors Used in Setting Rates; and the Risk of Utah Load Growth.

Q. WOULD PACIFICORP'S PROPOSED TRANSITION ADJUSTMENT MECHANISM CREATE A MISMATCH BETWEEN THE FIXED COSTS AND VARIABLE COSTS INCLUDED IN COST-OF-SERVICE RATES?

A. Yes.

Q. DID PACIFICORP ADDRESS THE MISMATCH BETWEEN FIXED AND VARIABLE COSTS IN ITS REBUTTAL TESTIMONY?

A. Yes. Ms. Omohundro indicated that CUB failed to acknowledge that the Company is continuously making capital investments and that under PacifiCorp's proposed Transition Adjustment mechanism the company would continue to bear the cost of these investments between general rate case filings. (PPL/701, Omohundro/4-5.)

Q. PLEASE RECAP CUB'S ARGUMENT RELATED TO UTAH LOAD GROWTH.

A. CUB argues that an annual update of the NVPC component of cost-of-service rates would result in annual rate increases for Oregon customers due to high cost of meeting Utah load growth. In addition, CUB argues that traditional regulatory lag provides incentive for PacifiCorp to prudently manage the cost of Utah load growth, whereas allowing annual NVPC updates would reduce this incentive. (CUB/100, Jenks/26-27.)

Q. PLEASE RECAP CUB'S ARGUMENT RELATED TO STATE ALLOCATION FACTORS.

A. CUB indicated that PacifiCorp's proposed Transition Adjustment mechanism would result in state allocation factors of different vintage being applied to the fixed and variable costs of PacifiCorp's generating plants. Given that Oregon load is growing less rapidly than Utah load, CUB argues:

> Once the Company has gone to the trouble of updating the allocation factors in a TAM filing, we know that Oregon's portion of fixed costs that was calculated in the last rate case is incorrect. If the Commission uses the proposed TAM, it would make far more sense to apply those new, more-accurate allocation factors to the revenue requirement from the last rate case. Once the Commission has decided that the new allocation factors are more accurate, it would be absurd not to apply them to all allocated costs. (CUB/100, Jenks/25, Lines 7-13.)

Q. DID PACIFICORP ADDRESS THIS STATE ALLOCATION ISSUE IN ITS REBUTTAL TESTIMONY?

A. Yes. Ms. Omohundro stated:

> By regularly updating allocation factors, the RVM actually helps protect Oregon customers from the impacts of Utah's rapidly growing load. When the allocation factors are reset, Oregon customers pay a smaller portion of the variable costs given that Utah customers will be assigned their fair share of the increased costs. (PPL/701, Omohundro/5, Lines 16-19.)

Q. DOES THE POTENTIAL HARM ASSOCIATED WITH THIS SET OF ISSUES RISE TO THE LEVEL WHERE THE COMMISSION SHOULD REJECT PACIFICORP'S PROPOSED TRANSITION ADJUSTMENT MECHANISM?

A. No. CUB has not established that these issues constitute a significant potential harm to ratepayers.

<u>Staff Recommendation</u>

Q. DOES STAFF SUPPORT THE USE OF PACIFICORP'S PROPOSED TRANSITION ADJUSTMENT MECHANISM?

A. Yes. PacifiCorp's proposed Transition Adjustment provides an accurate accounting of the likely impacts of direct access on PacifiCorp's system operations and can be expected to result in transition adjustment rates that reasonably balance the interests of retail electricity consumers and utility investors.

Q. DOES STAFF RECOMMEND A REVISION TO PACIFICORP'S PROPOSED POLICY REGARDING INCLUSION OF NEW RESOURCES IN ITS ANNUAL GRID MODELING?

A. Yes. Staff recommends that all improvements to existing resources be included in the company's annual GRID modeling. In addition, staff recommends that new resources that are in-service prior to the beginning of the rate effective period be included in the company's annual GRID modeling.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 170
WITNESS: Bill Wordley

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Surrebuttal Testimony

June 27, 2005

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Bill Wordley. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301. I am a Senior Economist in the Economic Research & Financial Analysis Division of the Utility Program of the Public Utility Commission of Oregon (OPUC).

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE?

A. My witness qualification statement is found in Staff/801, Wordley/1.

Q. WHAT IS THE PURPOSE OF THIS SURREBUTTAL TESTIMONY?

A. In this testimony I will address: (1) PacifiCorp's request to waive application of the New Resource Rule from OAR 860-038-0080(1)(b) in this case; and (2) certain resource, allocation and power cost-related adjustments proposed by Industrial Customers of Northwest Utilities (ICNU).

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. (1) Summary of the content of the Third Partial Stipulation in this docket; (2) Staff supports PacifiCorp's request to waive application of the New Resource Rule in this docket; and (3) Staff recommends that the Commission reject the following adjustments proposed by ICNU: (a) treating the four Qualifying Facility (QF) contracts added by the Company to its power resources in this case as "Existing" as defined by the Revised Protocol, and therefore directly assigning their costs to the situs state; (b) finding the acquisition and retention of the West Valley combustion turbines (CTs) lease to be imprudent, and therefore removing the cost of the resource from revenue requirement; (c) removing the cost of a voided combustion turbine lease agreement from rate base because the savings should be passed on to customers; (d) removing the impact of updating thermal plant heat rates and outages to reflect the most recent 48-month period; and (e) removing all outages that occurred during the UM 995 deferral period (November 27, 2000 through June 2, 2001) in determining historical average outage levels to use in this case.

Third Partial Stipulation

Q. PLEASE LIST THE ISSUES AGREED TO BY THE COMPANY AND STAFF IN THE THIRD PARTIAL STIPULATION.

A. First, Staff and the company agreed that if a RVM is ordered by the Commission to be implemented to set PacifiCorp's Transition Adjustment, that the final RVM GRID model run will include all adjustments proposed by the company in PPL/604-606 and PPL/607-608, except the Deferred Maintenance, Thermal Ramping, Station Service, and Planned Outages adjustments.

Second, in this Stipulation, Staff agreed to: (1) support PacifiCorp's application for a waiver of the New Resource Rule as it relates to the West Valley Lease, the Gadsby CTs, and the Current Creek projects; (2) accept the level of plant forced outages in the company's case; (3) not raise any issues regarding an alleged "mismatch" between a September 2005 base rate effective date and the calendar year 2006 test period; and (4) support the allocation treatment under the Revised PacifiCorp Inter-Jurisdictional

Cost Allocation Protocol (or the “Revised Protocol”) of the Company’s contracts with Qualifying Facilities (“QFs”) added to the Company’s power costs in this case.

Third, Staff and the company agreed that the company’s revenue requirement should be corrected to include a fuel handling charge. This results in a $2.49 million increase in the Company’s filed revenue requirement.

Waiver of New Resource Rule

Q. WHAT IS THE NEW RESOURCE RULE?

A. The pertinent language for this issue is from OAR 860-038-0080(1)(b), referred to as the New Resource Rule, and states:

> Electric companies must include new generating resources in revenue requirement at market prices, and not at cost, and such new generating resources will not be added to an electric company's rate base even if owned by the electric company;

Q. WHAT HAS PACIFICORP REQUESTED IN THIS CASE REGARDING THE APPLICATION OF THE NEW RESOURCE RULE?

A. The Company has requested a waiver from application of the rule as allowed by OAR 860-038-0001(4):

> Upon application by an entity subject to these rules and for good cause shown, the Commission may relieve it from any obligations under these rules.

and as instructed by the Commission in Order 05-133:

> If an electric utility wants to include a new resource in its revenue requirement at cost, as did PGE in docket LC 33, then the utility must file a request to waive the administrative rule.

PacifiCorp has asked that waiver of the rule apply to the West Valley CTs, Gadsby CTs, and Current Creek Phase One.

Q. WHAT DID THE COMMISSION CONCLUDE IN RESPONSE TO PGE'S REQUEST FOR A WAIVER FOR PORT WESTWARD FROM APPLICATION OF THE NEW RESOURCE RULE?

A. The Commission found in Order 04-376 that:

> Under the process done and analysis presented by PGE, we find that Pt WW [Port Westward] at cost serves the interests of the customers.

Consequently, the Commission concluded that PGE had shown good cause for waiver of OAR 860-038-0080(1)(b).

Q. WHAT WAS THE "PROCESS DONE AND ANALYSIS PRESENTED" ON WHICH THE COMMISSION BASED ITS DECISION?

A. The Port Westward project was compared to third party bids submitted in response to PGE's Request for Proposal (RFP). PGE found and the Commission agreed that construction and operation of Port Westward would benefit customers as compared to other resource alternatives.

Q. HAS PACIFICORP DEMONSTRATED INCLUDING WEST VALLEY, THE GADSBY CTS, AND CURRENT CREEK IN RATES AT COST PROVIDES BENEFITS FOR CUSTOMERS?

A. Yes. The acquisition process, cost and impact on customers of the West Valley CTs were analyzed in UI 196 and UE 134. The Commission concluded that the West Valley lease agreement is fair, reasonable, and not contrary to the public interest in Order 02-361 in UI 196. Staff analysis in UE 134 concluded the company was prudent in entering into the West Valley lease agreement (UE 134, Staff/200).

The Gadsby CTs were included in rates at the same time as West Valley, June 1, 2002, by UE 134 Order 02-343. The resource was acquired at same time and at a similar cost as West Valley as part of a plan to meet a large summer resource need on the eastside of PacifiCorp's system.

Current Creek resulted from RFP 2003A and is coming online this summer. The Utah PSC issued a Certificate of Public Convenience and Necessity for Current Creek on March 5, 2004. Staff analyzed the economic evaluation conducted by the company supporting the acquisition of Current Creek in discovery and in a meeting with the company, and concludes that the plant was the least cost option and will provide benefits to customers.

Q. WHAT DOES STAFF RECOMMEND REGARDING PACIFICORP'S APPLICATION FOR WAIVER OF OAR 860-038-0080(1)(b)?

A. Staff supports the company's application for waiver and the inclusion of West Valley, Gadsby CTs, and Current Creek at cost in this docket.

Allocation of Added Qualifying Facilities Contracts

Q. EXPLAIN THE ISSUE RAISED BY ICNU REGARDING THE ALLOCATION OF THE COST OF FOUR QF CONTRACTS ADDED TO COMPANY RESOURCES IN THIS CASE.

A. The Revised Protocol, adopted by the Commission in UM 1050 Order 05-021, treats "new" and "existing" QF contracts differently. The costs of existing QF contracts are assigned situs to the state that approved the contract. The costs of new QF contracts are allocated system-wide. Existing QF contracts are defined by the Revised Protocol as contracts entered into prior to the effective date of the Revised Protocol. ICNU has asserted that the effective date is when the Commission signed the order approving the Revised Protocol in January 2005. The four QF contracts in question were all entered into between August and November 2004. So ICNU claims the contracts are "existing" for allocation purposes.

Q. IS THIS THE CORRECT INTERPRETATION?

A. No. Section II of the Revised Protocol approved by the Commission in Order 05-521 states:

> The Protocol will be effective and apply to all PacifiCorp retail general rate proceedings initiated subsequent to June 1, 2004.

Even though the order was not signed until January 2005, because the Commission did not change the Section II language, the effective date of the Revised Protocol is June 1, 2004.

Q. WHY ARE EXISTING AND NEW QF CONTRACTS TREATED DIFFERENTLY BY THE REVISED PROTOCOL?

A. In the past, the utility commissions in states served by PacifiCorp have priced QF resources developed in there respective states differently. Avoided costs were calculated and applied to QF contracts in a variety of ways. During the multi-state process (MSP) this was discussed and it was decided that in the Revised Protocol each state would be directly assigned costs of the existing QF contracts approved by their commissions. For "new" QF contracts, the Revised Protocol says: "Costs associated with any New QF contract, which exceed the costs PacifiCorp would have otherwise incurred acquiring Comparable Resources[1], will be assigned on a situs basis to the State approving such contract." Subject to a cost comparison to comparable resources, new QF contract costs are allocated system-wide.

Q. DID STAFF REVIEW THE COSTS OF THE FOUR NEW QF CONTRACTS?

A. Yes. Staff reviewed the contracts and the economic evaluations done in support of the four new QF contracts and concluded that the costs were similar to comparable resources.

Q. WHAT DOES STAFF RECOMMEND REGARDING THE ALLOCATION OF THE FOUR NEW QF CONTRACTS?

A. Staff recommends that the Commission reject ICNU's proposed adjustment to treat the four new QF contracts as "existing".

Prudence of the West Valley CT Resource

Q. WHAT IS STAFF'S POSITION REGARDING THE PRUDENCE OF THE WEST VALLEY RESOURCE?

A. The initial acquisition of the West Valley resource in 2002 was prudent. In addition, last year PacifiCorp passed on an option in the West Valley lease agreement to terminate the lease, and that decision was prudent. Staff analyzed the initial acquisition of West Valley in UE 134 and concluded the company was prudent in entering into the West Valley lease agreement (UE 134, Staff/200). Through discovery in this docket, Staff reviewed the RFP 2004-X process conducted to solicit alternatives to West Valley from the market. Staff reviewed the economic evaluation of

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[1] Comparable Resource means Resources with similar capacity factors, start-up costs, and other output and operating characteristics.

alternatives and concluded that the company's decision to retain the West Valley lease was prudent. Staff recommends the Commission reject ICNU's proposed adjustment related to the prudence of West Valley.

Remove Cost of Terminated CT Lease from Rate Base

Q. PLEASE DESCRIBE THE CONFLICT OF INTEREST ICNU HAS ASSERTED PACIFICORP HAD REGARDING THE WAIVER OF CT LEASE COSTS.

A. In late 2001, PacifiCorp signed a contract with General Electric (GE) to lease mobile CT peaking units for installation at Gadsby. Prior to the expiration of the lease, GE provided PacifiCorp a turn-key offer to install new, larger and more efficient CTs at Gadsby and waive the remaining $7.5 million lease obligation. GE's offer, even excluding waiving the remaining lease obligation which was included in the offer, was better than the Pratt & Whitney CT purchase and installation offer that PacifiCorp had been pursuing. Staff sees no evidence of a conflict of interest in the decision the company made to go with the GE CT deal at Gadsby, and recommends that the Commission reject ICNU's proposed adjustment to decrease the level of the Gadsby CT plant in rate base by $7.5 million.

Updated Plant Outage and Heat Rates

Q. WHAT ISSUE HAS ICNU RAISED REGARDING THE PLANT OUTAGE AND HEAT RATES USED IN THIS DOCKET?

B. As has been the normal practice, PacifiCorp based the thermal outage and heat rates in its filed case on the average of the last four years plant of actual experience. The company updates these 48-month averages on a semi-annual basis with data ending March and September of each year. ICNU objected when the company updated the net variable power costs (NVPC) in this docket[2] using an updated 48-month period of outage and heat rates. ICNU claims it had insufficient discovery time to review the new data used.

Q. WHAT IS STAFF'S POSITION REGARDING THE USE OF UPDATED THERMAL PLANT OUTAGE AND HEAT RATES?

A. Staff's position is that the updated thermal plant outage and heat rates will not be used in the NVPC included in the base rate change, expected in September. However, the updated rates should be used to develop the NVPC underlying the Transition Adjustment mechanism (also referred to as the RVM), if the Commission decides in this docket that PacifiCorp will implement a RVM. This position is consistent with the last several PGE RVM cases. One of the objectives of the RVM is to get power costs as accurate as possible for the calendar year that the resulting rates will be in effect. Using the latest outage and heat rate data available helps achieve this objective. Staff recommends the Commission reject ICNU's proposed adjustment based on using the earlier period for plant outage and heat rates.

[2] PacifiCorp submitted two sets of supplemental testimony – PPL/604-606 and PPL/607-608 - updating NVPC.

Plant Outages during the UM 995 Deferral Period

Q. DESCRIBE ICNU'S PROPOSED ADJUSTMENT TO THE FOUR-YEAR AVERAGE PLANT OUTAGE RATE FOR UM 995 PERIOD OUTAGES.

A. The four-year period used to determine thermal plant outage rates in this docket, includes the November 1, 2000 through September 9, 2001 UM 995 deferral period. ICNU has proposed an adjustment in this case based on excluding all outages that occurred during the UM 995 deferral period in calculating the four-year average outage rates. ICNU says removal of all the UM 995 period outages will remove a "double recovery" of these outage costs, because the company is already collecting these costs as a result of the Commission's UM 995 deferral order.

Q. PLEASE EXPLAIN STAFF'S POSITION REGARDING ICNU'S PROPOSED ADJUSTMENT FOR PLANT OUTAGES.

A. Staff does not support this adjustment. The purpose for using a recent four-year average of outages in the determination of base rates is to reflect a normal level of outages that can be expected to occur during the period the rates are in effect. To exclude all outages for part of the historical four-year period used would distort the four-year average to something different than what would be expected to occur. The only outage excluded from the four years of historical outage data used in this case, was the five and one-half month Hunter 1 outage. This extensive of an outage is not expected to occur during the period the rates are in effect, and consequently is excluded from the historical outage data used.

Q. WHAT ABOUT ICNU'S CONTENTION THAT NOT EXCLUDING ALL UM 995 PERIOD OUTAGES FROM THE DATA USED IN THIS CASE WILL LEAD TO "DOUBLE RECOVERY"?

A. The UM 995 order allows PacifiCorp to recover excess power costs, partly caused by the Hunter 1 outage. All other outages that occurred during the UM 995 deferral period are consistent with the normal four-year average outage level in the NVPC in base rates in effect during that period. Consequently, there is no double recovery by including all the normal outages that occurred during the UM 995 deferral period in outage data used in this case. Staff recommends that the Commission reject ICNU's proposed adjustment regarding UM 995 period plant outages.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 170
WITNESS: Bill Wordley

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualifications Statement

June 27, 2005

WITNESS QUALIFICATION STATEMENT

NAME:	Bill Wordley
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist, Economic Research & Financial Analysis Division
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.
EDUCATION:	All course work towards Masters in Economics Portland State University B.S. Portland State University Major: Mathematics
EXPERIENCE:	Since August 2000 I have been employed by the Public Utility Commission of Oregon. Responsibilities include research and providing technical support on a wide range of cost, revenue and policy issues for gas, electric and telephone utilities. From March 1999 to August 2000 I worked as a consultant in the energy field working for electric utilities and utility organizations. Work included load forecasting and operations planning. From 1972 to 1999 I worked for PacifiCorp in various analytical and management positions dealing with long and short-term load, sales, and revenue forecasting, power operations planning, power contract optimization, merger and acquisition support, strategic planning support, market research, retail market planning, load-resource analysis, and power contract administration. Testified in some 30 regulatory proceedings in Oregon, Washington, Idaho, Montana, Wyoming, and California.

CASE: UE 170
WITNESS: Jack P. Breen III

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Surrebuttal Testimony

June 27, 2005

Q. PLEASE STATE YOUR NAME.

A. My name is Jack P. Breen III.

Q. ARE YOU THE SAME JACK BREEN THAT PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I provide testimony regarding PacifiCorp's treatment of its agreement with Georgia Pacific (GP), staff issue S-13 in this proceeding, I provide my assessment of PacifiCorp's proposed fuel handling adjustment, and I provide testimony regarding rate spread and rate design.

ISSUE S-13, GP POWER COST ADJUSTMENT AND FUEL HANDLING

Q. WHAT ARE OTHER PARTIES' RECOMMENDATIONS FOR THE GP POWER COST ADJUSTMENT?

A. PacifiCorp also recommends an adjustment (system) of $7,324,891 (*see* PPL/1600, Wrigley/3). It is my understanding that ICNU will also be supporting this amount.

Q. DID PACIFICORP MAKE A RECOMMENDATION REGARDING FUEL HANDLING IN ITS REBUTTAL TESTIMONY?

A. Yes. PacifiCorp requests that the Commission include $8,884,703 in fuel handling costs.

Q. IS THIS ADJUSTMENT APPROPRIATE?

A. Yes. It is regrettable that it was first raised in rebuttal, but I understand that the company came across this inadvertent omission while researching the Georgia Pacific contract. I agree with the company that the correction should be made so that the test year reflects the costs the company is expected to incur when the rates will be in effect.

RATE SPREAD AND RATE DESIGN

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY REGARDING THIS AREA?

A. First, I address the issue of billing variability caused by changes in billing cycles in the presence of blocked rates. Second, I address fundamental rate spread and rate design issues that affect the calculation of the rate mitigation adjustment. Third, I address one issue regarding Klamath Irrigator Rates and indicate I will address the other issues under the separate procedural schedule for those issues. Fourth, I address other rate spread and rate design issues.

BILLING PERIOD VARIABILITY

Q. MR. JENKS, AT CUB/100, JENKS/30-37, RECOMMENDS USING A DAILY BLOCK RATE DESIGN TO ADDRESS VARIABILITY IN THE LENGTH OF CYCLE PERIODS. DO YOU AGREE WITH HIS RECOMMENDATION?

A. In part. I agree that variability outside the range of normal meter reading cycles raises fairness issues, particularly with block rates. However, the use of a daily block rate would be difficult to explain to customers, and more difficult to administer.

Q. MR. GRIFFITH, AT PPL/1204, GRIFFITH/4, RECOMMENDED RETAINING THE MONTHLY BLOCK RATE STRUCTURE, PRORATING BILLS IF THE BILLING CYCLE IS LONGER THAN 34 DAYS OR SHORTER THAN 26 DAYS, AND INCREASING REVENUE REQUIREMENT BY $175,000 TO ACCOUNT FOR THE CHANGE. DO YOU AGREE WITH HIS RECOMMENDATION?

A. In part. I agree the company should maintain monthly block billing for bills issued within the normal meter reading cycle. The problem develops, as it did for the Corvallis customer mentioned by Mr. Jenks, when the read is over 34 days. Even though I agree with Mr. Griffith's proposal to prorate bills issued for periods longer than 34 days and shorter than 26 days, I do not agree with his proposal to increase revenue requirement by $175,000.

Q. WHY IS THAT?

A. PacifiCorp was required to redeploy meter readers to address storm outages during the winter of the period used to determine the billing determinants. This caused an increase in certain billing cycles. After the storm outages, Mr. Griffith characterized this redeployment of meter readers as a “rare” instance. I recommend the Commission consider it a nonrecurring event. The other reason for variation in the length of cycles is PacifiCorp’s reorganization of meter reading cycles. Absent further information regarding the nature of the billing determinants, I recommend that the Commission not allow the additional $175,000 increase in revenues.

RATE MITIGATION ADJUSTMENT

Q. WHAT IS THE PURPOSE OF THE RATE MITIGATION ADJUSTMENT?

A. It balances the objective of having cost-based rates and the objective of mitigating sharp rate increases for customers that are currently priced below their cost of service.

Q. SHOULD THE RATE MITIGATION ADJUSTMENT BE CALCULATED BY LOOKING STRICTLY AT BASE RATES OR SHOULD IT CONSIDER THE OTHER ADJUSTMENTS MADE TO ESTABLISH NET RATES?

A. The overall net rate is important. The period the rates will be in effect is also a consideration because certain adjustments may, or may not, be in effect during that period. As the Commission previously determined, the calculation of the rate mitigation adjustment should not take BPA adjustments into account (*see* Order 01-787 at 52).

Q. DO YOU AGREE WITH MR. HIGGINS' AND MR. GRIFFITH'S RECOMMENDATIONS TO RETAIN USE OF THE PRACTICE OF ALLOWING THE RATES OF A CUSTOMER CLASS TO CHANGE NO MORE THAN 1.5 TIMES THE OVERALL RATE CHANGE?

A. Yes, but I have different recommendations regarding implementation. First, contrary to Mr. Griffith's recommendation, it should be applied after, not before, consideration of the termination of Schedule 94.[1] Mr. Griffith's recommendation results in an 8% increase in small general service customer rates in the face of an overall rate change of 3.1% (*see* PPL/1206,

[1] Schedule 94 is related to PacifiCorp's recovery of excess power costs and is scheduled to terminate when new UE 170 rates go into effect.

Griffith/1). Mr. Griffith's approach is inconsistent with the policy of moving customers gradually toward their cost of service. In addition, I do not believe it is equitable to give certain customers rate decreases in the face of an overall rate increase.

Q. DO YOU AGREE WITH MR. HIGGINS' RECOMMENDATION TO GIVE A THREE PERCENT INCREASE TO CUSTOMERS EVEN IF 1.5 TIMES THE OVERALL RATE CHANGE IS LESS THAN THREE PERCENT?

A. Yes. I think that is a reasonable recommendation. For example, if the overall rate increase is 1%, customers would otherwise receive only a 1.5% increase. I believe in the face of a small rate increase, it is reasonable to allow an increase greater than 1.5 times the overall increase up to three percent to move customers toward cost of service. In Order 01-787, at page 52, the Commission capped a class rate increase at fifteen percent. There is precedent for using percentage increases as a test for reasonableness for class rate changes.

Q. DO YOU AGREE WITH MR. HIGGINS' RECOMMENDATION TO ALLOW A 1.5 CENT INCREASE FOR AGRICULTURAL PUMPING CUSTOMERS?

A. No. I agree with Mr. Griffith that such a change would violate the principles that have been used to gradually move customers to cost of service rates.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR CALCULATING THE RATE MITIGATION ADJUSTMENT.

A. I recommend that the Commission apply the 1.5 times the overall rate change principle to the net rate changes, including the termination of the

Schedule 94 adjustments. Other than Schedule 94, I agree with PacifiCorp's position of what is, or is not, included in the adders (*see* PPL/1206, Griffith/1, footnotes 1 and 2). I do not recommend rate decreases in the face of an overall rate increase. I concur that a rate increase up to three percent for a class whose rates are below its share of the cost of service is reasonable when the application of the 1.5 times the overall increase would yield an increase less than three percent. I do not agree with the proposal to use 1.5 cents per kWh as a cap rather than the 1.5 times the overall rate change principle.

SCHEDULE 33 – KLAMATH IRRIGATOR RATES

Q. DOES YOUR TESTIMONY ADDRESS MS. IVERSON'S AND MR. SCHOENBECK'S TESTIMONY REGARDING THESE MATTERS?

A. I address one issue in this testimony. That issue is whether Schedule 33 irrigation customers, if they are moved to typical irrigation retail rates, are sufficiently different from existing Schedule 41 customers, so as to constitute the basis for a new class. It should be noted for the record that irrigators that have not registered 1,000 kW or more are served on Schedule 41, and larger irrigators are served on Schedule 48. So to that extent, there is already more than one schedule for irrigators.

Q. WHEN WILL YOU ADDRESS THE REMAINING ISSUES?

A. I will address the remaining issues under the separate procedural schedule set for addressing irrigator rates.

Q. MR. SCHOENBECK AND MS. IVERSON INDICATE THERE IS REASON TO BELIEVE IT COSTS LESS TO SERVE SCHEDULE 33 CUSTOMERS. DOES THIS WARRANT A SEPARATE SCHEDULE?

A. No. I do not believe the differences, even if they exist, are sufficient to warrant a separate schedule. Although I believe it is possible, it would be unprecedented to have this type of geographical deaveraging for determining classification. Ms. Iverson, at KOPWU/100, Iverson/3, indicates "Off-Project irrigators' average use per customer is almost four times greater than Schedule 41 usage. Thus, there may be reason to expect that the costs of serving Off-Project Customers are lower, on average, than serving other irrigators." If the Klamath irrigators paid normal retail rates, the price elasticity effects would cause a decrease in usage. If the Klamath irrigators are moved to normal retail rates, they should be grouped with the other Oregon irrigators and served from common schedules. Of course, if the Klamath irrigators continue with the existing contract rates, or are served under a rate mitigation process, it is reasonable to have a separate basic schedule or adjustment schedule that reflects such differences.

OTHER RATE SPREAD AND RATE DESIGN ISSUES

Q. MS. IVERSON RECOMMENDS USE OF THE JURISDICTIONAL COST ALLOCATION STUDY ASSUMPTIONS RATHER THAN THE PACIFICORP MARGINAL COST STUDY FOR THE PURPOSE OF ALLOCATING GENERATION AND TRANSMISSION COSTS TO ENERGY AND DEMAND COMPONENTS. DO YOU AGREE?

A. No. PacifiCorp proposes the use of a cost causative method in its marginal cost study based on the cost of simple cycle and combined cycle combustion turbines. There is an analytical basis for that method of allocating generation and transmission costs to energy and demand components. On the other hand, Ms. Iverson asks the Commission to use, and bases her calculations on, the factors used in the PacifiCorp's multi-state jurisdictional allocation process. Ms. Iverson states at ICNU/300, Iverson/7, that the "Revised Protocol classifies 75% as demand-related and 25% as energy-related." These factors, however, are not revised and have been in place for many years. For instance, the Accord Method that went into effect for utilization in filings based on 1993 data contained the same 75% and 25% factors. In the recent process, the states could not reach agreement on new factors and the old factors were retained. The Commission should adopt the PacifiCorp method that is analytically supportable rather than the factors based on historical negotiations.

Q. DOES MS. IVERSON'S CITATION OF MR. TAYLOR'S UE 147 TESTIMONY THAT THE ENERGY COMPONENT IS CONSTITUTING A

LARGER PORTION OF THE TOTAL GENERATION COST CONCERN YOU?

A. No. I would expect this type of change to occur as fuel prices change or market conditions change. Ms. Iverson's recommendation to use fixed percentages, such as the 25% used in the MSP negotiation process, is inferior to the company's recommendation for separating demand and energy costs.

Q. IS IT ALSO TRUE THAT PACIFICORP'S MARGINAL COST STUDY TECHNIQUE FOR TRANSMISSION IS SUPERIOR TO USE OF THE JURISDICTIONAL COST STUDY?

A. Yes. PacifiCorp has a reasonable rationale in its marginal cost study. There is no indication that the MSP jurisdictional cost study is superior.

Q. IS IT REASONABLE TO NOT DIFFERENTIATE MARGINAL GENERATION COSTS BY HOUR OF USE IN THE MARGINAL COST STUDY?

A. Yes, this is a reasonable assumption for purposes of assigning responsibility to customer classes. A gas turbine is the unit on the margin in the marginal cost study. It is reasonable to use this as a basis for the marginal cost study. The marginal cost study is used to allocate cost responsibility to classes. It is not used to set price signals – the rate design establishes the price signals. Ms. Iverson alludes to price signals in her testimony regarding marginal cost studies (*see* ICNU/300, Iverson/8, line 9) and goes on to say "ironically" the company sets rates based on on-peak and off-peak prices. I do not find it ironic. The company properly differentiates between the rate spread and rate design processes in formulating its recommendations.

Q. WHAT IS YOUR ASSESSMENT OF THE RECONCILIATION STUDY PROVIDED IN EXHIBIT ICNU/303?

A. The study should not be adopted by the Commission. A fundamental piece of the reconciliation is the unbundled cost of the functions. The company has complied with OAR 860-038-0220 and unbundled the cost of generation. Exhibit ICNU/303 is not based on any further unbundling of the company's assets and expenses used to set revenue requirement. As I understand it, it is merely based on the 51% split that employs the use of the jurisdictional cost study factors. Exhibit ICNU/303 does not reflect a refinement in the unbundling process and should not be considered by the Commission.

Q. DO YOU SUPPORT PACIFICORP'S EFFORTS TO IMPLEMENT TIME OF DAY PRICING FOR CUSTOMERS OVER 1,000 KW?

A. Yes. I recommend the Commission adopt PacifiCorp's proposed time of day pricing for its largest customers because of the benefits related to improved reliability, reduced costs for delivered energy, and lower and more stable electricity rates. Customers on time of day pricing can benefit further to the extent they shift some load to off-peak hours. The following is an excerpt from Lisa Schwartz's demand response report presented to the Commission at its June 3, 2003, Public Meeting:

> A report funded by the Electric Power Research Institute (footnote omitted) found "overwhelming evidence" from dozens of studies that all customer classes respond in modest but significant and consistent ways to time-varying electricity prices. Responses vary widely, depending on electricity usage levels, appliance ownership or electricity intensity of operations, ability to shift loads to off-peak times, on-site generation and other factors.

Q. IS A THREE MILL DIFFERENTIAL SUITABLE FOR INITIAL IMPLEMENTATION?

A. Yes. I recommend that PacifiCorp continue to evaluate the appropriate differential over time, but three mills is a reasonable level for initial implementation. The Commission should not reject PacifiCorp's time of use pricing as suggested by Ms. Iverson because the initial differential is based on the company's judgment. Portland General Electric (PGE) has had similar time of day pricing for customers with a facility capacity greater than 1,000 kW since 1995. Currently, the differential between PGE's on-peak and off-peak rates is about eight mills. PacifiCorp's recommendation is a conservative approach to implementing time of day pricing.

Q. DO YOU AGREE WITH MS. IVERSON THAT THE COMMISSION SHOULD REJECT TIME OF USE PRICING DUE TO THE METHODOLOGY USED TO PREPARE THE MARGINAL COST STUDY?

A. No. As discussed previously, Ms. Iverson does not properly differentiate between the purpose of the rate spread and rate design processes. The marginal cost study is used to determine the rate spread among customer classes. Rate design is a process of designing rates to recover the cost responsibility allocated to the class. Rate design is based on the marginal cost study as well as other considerations such as the difference in energy costs between on-peak and off-peak periods. Time of day pricing is not simply, as Ms. Iverson indicates, "a rate design strategy to boost revenues for energy sold to large power users during on-peak times." Customers that shift energy use to off-peak times will see lower bills than they would otherwise. All customers benefit from such demand response.

Q. DO YOU AGREE WITH MR. GRIFFITH AT PPL/1204, GRIFFITH/7, THAT IT IS APPROPRIATE TO ADJUST THE RATES FOR THE FIRST BLOCKS OF SCHEDULE 28 AND SCHEDULE 30 TO REFLECT THE EQUALIZATION OF THE SCHEDULE 28 AND 30 TAILBLOCK RATES?

A. Yes. The equalization of the tailblock rates should not supersede the requirement to set rates based on the unbundled costs to serve that class.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

CASE: UE 170
WITNESS: Bryan Conway
Judy Johnson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

Surrebuttal Testimony

<u>Redacted Version</u>

June 27, 2005

Q. PLEASE STATE YOUR NAMES, BUSINESS ADDRESSES AND OCCUPATIONS.

A. My name is Bryan Conway. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551. I am employed by the Public Utility Commission of Oregon (OPUC) as the Manager of the Economic and Policy Analysis Section in the Economic Research and Financial Analysis Division.

My name is Judy Johnson. My business address is also 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551. I am employed by the Public Utility Commission of Oregon (OPUC) as the Manager of the Revenue Requirements Section in the Electric & Natural Gas Division.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. Our Witness Qualifications Statement are found in Exhibit Staff/1001, Conway-Johnson/1-2.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The purpose of our testimony is to respond to the testimony of PacifiCorp witness Mr. Uffelman, Industrial Customers of Northwest Utilities (ICNU) witness Mr. Selecky, and Citizens' Utility Board of Oregon (CUB) witness Mr. Jenks. Specifically, our testimony will cover the use and application of the traditional "stand-alone" method (as opposed to a consolidated effective tax rate method) for computing the income tax expense component of cost of service. Further, our testimony presents a method of quantifying the burden associated with the "benefits-burdens" test.

Finally, our testimony presents alternatives to changing the method of calculating taxes for the Commission to consider for Oregon ratemaking.

Q. PLEASE SUMMARIZE THE POSITION OF THE PARTIES.

A. PacifiCorp testifies that no adjustment should be made and that customers do not bear the burden of the debt at PHI. (*See* PPL/400, Uffelman/11, lines 11-20.) CUB testifies that a $14.8 million reduction in revenue requirement is appropriate. (*See* CUB/100, Jenks/18 lines 8-12.) ICNU testifies that a $27.58 million reduction in revenue requirement is appropriate. (*See* ICNU/200, Selecky/17, lines 13-18.)

Q. HAVE YOU PREPARED ANY EXHIBITS?

A. Yes. We prepared Staff/1001, consisting of two pages and Staff/1002, consisting of 13 pages.

<u>The Stand-Alone Method</u>

Q. PLEASE DEFINE THE STAND-ALONE METHOD OF CALCULATING TAXES.

A. Under the "stand-alone" method, ratemaking tax expense is calculated based on the items of income and expense included in the regulated utility's revenue requirement calculation. Under traditional regulatory practices, ratemaking tax expense is computed based on the tax liability that arises from net income generated by the provision of the regulated service including the return required by equity investors. In other words, ratemaking tax expense is "caused" by the income or expense included in rates. Income or expenses not included in rates, such as non-operating income or disallowed expenses, are excluded from the ratemaking tax calculation under the traditional method.

Q. IS THE STAND-ALONE METHOD CONSISTENT WITH PAST COMMISSION DECISIONS?

A. Yes. In all historic rate cases, the Commission has used the "stand-alone" method to calculate income taxes. To our knowledge, this is the first time the "stand-alone" method has ever been challenged.

Q. HOW DOES THE STAND-ALONE METHOD DIFFER FROM THE METHOD ADVOCATED IN THIS CASE BY CUB AND ICNU?

A. ICNU's and CUB's proposals seek to capture for customers the tax benefit associated with the loan that PacifiCorp's shareholder, PHI, used to purchase its investment in PacifiCorp.

Q. HAS THE OPUC STAFF RECENTLY REVISITED ITS POSITION WITH RESPECT TO CALCULATING TAXES FOR SETTING RATES?

A. Yes, the issues surrounding how taxes are estimated have recently received a lot of interest primarily due to Enron's demise. However, the same issues apply to all utilities that have a holding company or unregulated subsidiaries.[1] And, taxes have been raised as an issue in this case. Staff recently created a white paper for presentation to the Oregon Senate. In the Staff's white paper, staff compared the "stand-alone"

[1] Even if a utility did not have a parent or any affiliates, and was solely a stand-alone company, actual taxes paid will differ from those included in rates because the company's actual financial performance will differ from the projections established in a general rate case.

method with several other methods and concluded that the “stand-alone” method was superior for a number of reasons.

Q. WHAT IS YOUR CURRENT POSITION WITH RESPECT TO CALCULATING TAXES FOR RATEMAKING?

A. Our position is that the Commission should calculate taxes based upon the stand-alone method, but that it can consider tax benefits at the holding company level if it determines that including the benefits in rates meets a “benefits – burdens” test. (*See generally*, memorandum by Jason W. Jones attached as Exhibit Staff/1002, Conway-Johnson/1-9.)

Q. WHAT IS THE BENEFITS-BURDENS TEST?

A. Focusing on the interest deduction, the benefits-burdens test means that customers are entitled to a share of the tax benefits due to PHI’s deduction of interest expense to the extent customers bear the burden of the debt at PHI.

Q. COULD CUSTOMERS BEAR SOME BURDEN ASSOCIATED WITH PHI DEBT EVEN THOUGH CUSTOMERS ARE NOT LEGALLY OBLIGATED TO PAY THE DEBT?

A. Yes. Customers could be negatively impacted by PHI debt even though customers have no obligation to pay the debt.

Q. IS A GENERAL RATE CASE THE APPROPRIATE PLACE FOR ADDRESSING THE ISSUE OF THE LEVEL OF TAXES THAT SHOULD BE INCLUDED IN RATES?

A. Yes, taxes are an expense included in establishing revenue requirements in a general rate case. However, some consideration should be given to the tax treatment in a general rate case to reflect the agreements adopted by the Commission, if any, when the holding company was formed. For PacifiCorp, the holding company was formed as a result of ScottishPower's application under ORS 757.511 (the Acquisition).

Q. PLEASE EXPLAIN.

A. During the review of the Acquisition, ring fencing was an important issue. Simply put, ring fencing attempts to isolate the regulated utility from its parent or other affiliates. In part to insulate customers from the PacifiCorp's parent (PHI), the loan (*i.e.,* debt) used to fund the acquisition was recorded on the books of PHI, not on the books of PacifiCorp, thereby attempting to ensure that none of the costs associated with the acquisition are reflected in PacifiCorp's revenue requirement.

Q. WHAT OTHER RING FENCING PROVISIONS WERE ADOPTED?

A. There were several other ring fencing provisions adopted including minimum equity requirements, requirements to provide access to information at ScottishPower, and "hold harmless" provisions.

Q. WHAT WERE THE "HOLD HARMLESS" PROVISIONS FROM ORDER 99-616?

A. Two provisions in Order No. 99-616 seem the most on point. They are listed below.

Merger Condition No. 7

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

> Merger Condition No. 10

> ScottishPower/PacifiCorp guarantee that the customers of PacifiCorp shall be held harmless if the merger between ScottishPower and PacifiCorp results in a higher revenue requirement for PacifiCorp than if the merger had not occurred. This includes, but is not limited to, costs associated with currency exchange agreements not otherwise authorized by the Commission. However, this hold harmless provision shall not apply to incremental costs associated with cost-effective investments in renewables and conservation subsequently approved by the Commission.

Q. HAVE THE RING FENCING PROVISIONS, INCLUDING THE HOLD HARMLESS CONDITIONS, INSULATED CUSTOMERS FROM PACIFICORP'S PARENT?

A. Perhaps. As CUB points out in its testimony, the ratings agencies examine the consolidated entity rather than viewing PacifiCorp as a stand-alone entity. The quoted press releases demonstrate that PacifiCorp's ratings have suffered due to credit concerns at the parent. (*See* CUB/100, Jenks/10 line 5 through Jenks/12 line 3.) This method of examining utilities has led to what is loosely known as the "three notch rule." The three notch rule states that subsidiaries are not generally granted a rating more than three notches above their parent.[2] According to this rule, if a parent is rated BBB-, then the subsidiary cannot be rated higher than A-.

[2] PGE's debt rating is a noted exception to this rule.

In response, Mr. Williams argues that PacifiCorp's credit rating has been favorably impacted by PacifiCorp's association with ScottishPower. (See PPL/304, Williams/12, line 1 through Williams/13, line 15.)

Both CUB's arguments and PacifiCorp's arguments indicate that PacifiCorp's ratings are affected by ScottishPower. This would imply that the ring fencing was not 100 percent effective. However, other conditions of the merger could be sufficient to ensure customers are held harmless, such as the merger credits.

Q. ARE CUB'S AND PACIFICORP'S ARGUMENTS CONSISTENT WITH EACH OTHER?

A. Yes. As Mr. Williams points out in his testimony, "…Mr. Jenks' argument with respect to rating agencies tells an incomplete story." It appears that Mr. Williams is trying to tell the rest of the story. Taken together, we conclude that PacifiCorp's ratings suffer due to debt at PHI but, PacifiCorp's ratings are currently benefited by PacifiCorp's relation to ScottishPower. The net result of these two effects is unknown.

Q. WHAT CURRENT BENEFITS DOES MR. WILLIAMS CITE TO SCOTTISHPOWER'S OWNERSHIP OF PACIFICORP?

A. The citations Mr. Williams chose indicate the following benefits:

> 1. ScottishPower has implemented operational efficiencies and fortified relations with the state regulators.
>
> 2. In May 2005, ScottishPower's consolidated credit profile compensated for the U.S. utility's weaker stand-alone metrics.

Q. DOES THIS DEMONSTRATE THAT THE MERGER HAS NOT HARMED PACIFICORP'S CUSTOMERS?

A. No. It is difficult to determine if PacifiCorp, absent ScottishPower would have sought out operational efficiencies or fortified relations with state regulators. PacifiCorp would need to show that the cost efficiencies are a result of ScottishPower's unique knowledge, leadership, or synergies. Further, while we can determine PacifiCorp's stand-alone metrics, we cannot readily observe what PacifiCorp's stand-alone metrics would have been absent the merger. Perhaps a high dividend payout requirement at ScottishPower resulted in increased demands for cash at PacifiCorp and depressed PacifiCorp's credit metrics.

Q. DO THE RECENT EQUITY INFUSIONS MADE BY SCOTTISHPOWER DEMONSTRATE THAT CUSTOMERS HAVE NOT BEEN HARMED BY THE MERGER?

A. No. First, as CUB points out, this could be a way of increasing profits from double leverage. (*See* CUB/100, Jenks/12, line 4 to Jenks/13, line 5.) Another rationale could be that ScottishPower has been providing the equity infusions in order to achieve a better sales price for PacifiCorp. Yet another rationale could be that PacifiCorp, on a stand-alone basis, was performing poorly and required support from ScottishPower. A fourth potential explanation is that the equity infusions are needed to maintain an appropriate capital structure while embarking on a significant resource construction plan. To date, there is insufficient analysis provided by

PacifiCorp to conclude that equity infusions and other actions demonstrate that PacifiCorp's cost of capital is lower due to the merger.

Q. WHAT ARE PACIFICORP'S AND SCOTTISHPOWER'S CURRENT BOND RATINGS?

A. For unsecured debt, both PacifiCorp and ScottishPower are rated BBB-. PacifiCorp's Senior Secured debt is rated A-.

Q. HOW COULD DEPRESSED BOND RATINGS AFFECT CUSTOMERS' RATES?

A. The most direct way PacifiCorp's customers' rates would be affected would be through the interest rate on PacifiCorp's long-term debt. The higher the interest rate, the higher the cost to obtain funding needed to maintain company operations and investments. The Commission has traditionally set the cost of long-term debt using an embedded approach. Therefore, any increased costs in PacifiCorp's borrowings, absent any adjustments, would be included in rates, once rates are established, and would persist over the life of the borrowings unless the Commission made an adjustment to the cost of debt in a later rate proceeding.

Q. DOES THIS MEAN THAT CUSTOMERS ARE BEARING THE BURDEN OF THE DEBT AT PHI?

A. Perhaps. It is possible that customers are bearing a "burden" to the extent the parent caused PacifiCorp's debt costs to be higher than it would otherwise would have been and the Commission did not adopt an adjustment to remove this effect.

Q. HAVE CUB AND ICNU DEMONSTRATED THAT ALL OF THE TAX BENEFITS ASSOCIATED WITH THE INTEREST EXPENSE BELONG TO CUSTOMERS?

A. No.

Q. PLEASE EXPLAIN.

A. The ratings agency reports indicate that PacifiCorp's ratings have suffered, and it is likely that PacifiCorp's debt issuances since the Acquisition have been more costly due to concerns about its parent's credit. However, we do not currently know with certainty to what extent PacifiCorp's borrowings have been more costly. Like most issues, estimation and analysis is needed to develop adjustments and recommendations. Due to the ring fencing provisions adopted in Order Number 99-616, there is some degree of separation between the credit quality of PacifiCorp and its parent. However, the ring fencing may not be 100 percent effective, so some customer harm may have occurred. Based upon existing information, it is difficult to be precise in determining what PacifiCorp's rating would be absent the debt at PHI.

Q. CAN YOU ESTIMATE THE EFFECT OF THE DEBT AT PHI ON PACIFICORP'S COST OF BORROWING?

A. Yes. However, due to the nature of this particular adjustment; our estimates will likely be imprecise for a couple of reasons. First, we would be trying to determine what the ratings agencies would have rated PacifiCorp debt absent the debt at PHI. The ratings agencies do not strictly use a formulaic approach and there is a considerable amount of judgment that goes into the ratings. Therefore, any reliance on simple credit metrics excludes the rating analyst's judgment and analysis. Second, assuming an improved rating (or improved outlook) was found, we would need to estimate what the impact would have been on the interest rates PacifiCorp would have obtained on its debt issued since the merger. Because the rating agency's opinion is but one piece of information used by banks to set rates, this too is problematic. The problem with trying to determine what PacifiCorp's costs would have been with any degree of precision was addressed by the Commission in the last ORS 757.511 filing. In Order 05-114, the Commission said,

> "[t]his complexity ensures that any assertion by Staff and Intervenors that the acquisition would lead to a higher PGE debt cost would likely be met with a response that such an assertion is overly simplistic. Also establishing a precise increase in debt cost, as implementation of the "hold harmless" condition requires, would be a difficult and contentious task with uncertain results."

Q. DID YOU MAKE ANY SIMPLIFYING ASSUMPTIONS?

A. Yes. Assumptions were necessary for several reasons. First, the impact of PHI debt may have been enough to warrant a change in one period but not another. Similarly, the difference between A and BBB spreads change over time. First, spread information from June 30, 2004, was used and applied to all issuances. The spread information is attached as Exhibit Staff/1002, Conway-Johnson/10. Second, a holding period, on average, of 5-, 7-, and 10-years was used. Third, we assumed the level of debt at

PHI was $2.375 billion with an interest rate of 6.75 percent. Finally, PacifiCorp was assumed to maintain its current business position of 5[3]. Finally, I consolidated the debt at PHI onto PacifiCorp's balance sheet in order to calculate the financial metrics.

Q. BECAUSE PRECISE ESTIMATES OF THE HARM OR BURDEN ON CUSTOMERS FROM THE DEBT AT PHI CANNOT BE OBTAINED, SHOULD THE COMMISSION ASSUME NO BURDEN EXISTS?

A. No. Just because a burden is difficult to measure precisely does not mean that it should not be addressed. While we do not believe the Commission should assume no burden, we recommend the Commission not adopt the full amount of burden as measured by CUB or ICNU. The true amount of burden likely lies somewhere in between.

Q. WHAT WOULD BE THE MOST ACCURATE METHOD OF DETERMINING THE EFFECT ON PACIFICORP'S COST OF DEBT DUE TO CONCERNS WITH PACIFICORP'S PARENT'S CREDIT?

A. The most accurate method of determining the effect on PacifiCorp's ratings would be to ask one of the ratings agencies for an advisory report or study. PacifiCorp could purchase this report and provide it to the Commission. After the difference in ratings is known, an estimate of the different spreads could be obtained by reviewing historic bond information. However, this study may not fit within the timeframes in this docket.

[3] Standard and Poor's assigns business risk positions to the company's it rates. The higher the business position, the lower the financial metrics can be and still maintain investment grade ratings.

Q. DO YOU HAVE AN ESTIMATE OF THE INCREASED COSTS DUE TO THE DEBT AT PHI?

A. Yes. PacifiCorp's ratings could be as much as one full rating higher, if not for PHI's debt. A full rating, at June 30, 2004, spreads, would lead to an approximate increase in all-in costs of 53 basis points, going from BBB to A ratings, for debt issued. PacifiCorp issued $1.9 billion in debt between 2000 and current (*See* Response to Staff Informal Data Request attached as Exhibit Staff/1002, Conway-Johnson/11) and this makes up 47 percent ($1.9 billion/$4 billion) of PacifiCorp's total debt. Using the revenue requirement model in UE 170, 53 basis points, and the ratio of affected debt to unaffected debt, is worth approximately $4.6 million annually. (53 basis points are worth $9.811 million).

Q. HOW DID YOU ARRIVE AT THE CONCLUSION THAT PACIFICORP'S RATING COULD BE IMPROVED BY AS MUCH AS A FULL RATING GRADE?

A. By calculating four financial ratios that are used by the ratings agencies. These ratios were calculated assuming the alternatives of the PHI debt on PacifiCorp's books and assuming no PHI debt on PacifiCorp's books. These ratios were compared to the financial targets used by Standard & Poor's. For all four metrics, the result of assuming PHI's debt was on PacifiCorp's balance sheet resulted in a decrease in the rating of one full grade. The results of the calculations and Standard & Poor's financial targets are attached as Exhibit Staff/1002, Conway-Johnson/12-13.

Q. WHY DID YOU ASSUME THE DIFFERENCE IN SPREADS BETWEEN BBB AND A FOR RE-PRICING PACIFICORP'S DEBT?

A. PacifiCorp's unsecured debt is BBB-. PacifiCorp's senior secured debt is A-. In order to view the impact on all of PacifiCorp's debt, a BBB was assigned to the metrics with PHI's debt included. Without PHI's debt, an A rating was assigned. When you look at the financial targets, you will see that assuming PHI's debt on PacifiCorp's books results in ratings consistent with BB to B ratings. Without PHI's debt, PacifiCorp's ratings range from BB to BBB based strictly on the four metrics and Standard & Poor's financial targets. The difference between the mechanical calculations and actual ratings likely reflect judgment and qualitative factors considered by Standard & Poor's.

Q. DO YOU CONSIDER THIS A PRECISE ESTIMATE OF THE IMPACT OF PHI'S DEBT ON PACIFICORP'S COST OF DEBT?

A. No, for the reasons discussed above.

Q. WHAT ALTERNATIVE METHODS DOES THE COMMISSION HAVE IF IT WISHES TO MAKE AN ADJUSTMENT EQUAL TO THE AMOUNT PACIFICORP'S DEBT COSTS HAVE INCREASED DUE TO PHI'S DEBT?

A. The Commission could make an adjustment using any of the following methods. First, it could adjust tax assumptions to include a portion of the consolidated tax savings by finding that, to some extent, customers "bear the burden" of PHI's debt. Second, the Commission could seek to enforce the hold harmless condition that ScottishPower agreed to and the Commission adopted in Order 99-616 and reduce PacifiCorp's cost of capital. Finally, the Commission could adjust PacifiCorp's capital structure to acknowledge the ratings agency's view which incorporates debt from the holding company as funding a portion of PacifiCorp's equity. Adjusting PacifiCorp's capital structure to include more debt and less equity would reduce rates. Additionally, imputing additional debt on PacifiCorp's capital structure would be a direct way to impute some additional tax benefits for customers.

Q. COULD THERE BE AN ADVANTAGE IN USING A TAX ADJUSTMENT AS COMPARED TO A REDUCING THE COST OF DEBT?

A. Yes. The benefits-burdens test may be a more direct method of adjusting rates to acknowledge the burden of PHI's debt on PacifiCorp's customers.

Q. PLEASE EXPLAIN.

A. In this situation, the benefits-burdens test looks at the question of whether or not customers bore the burden of paying the deductible expenses that generated the savings. Assuming there is not a 100 percent effective ring fence, customers will be bearing some burden.

On the other hand, in order to adjust the cost of debt or capital structure, the Commission would need to conclude that either, PacifiCorp is seeking "a higher cost of capital than that which PacifiCorp would have been authorized on its own" (Merger Condition No. 7) or the "merger between ScottishPower and PacifiCorp result[ed] in a higher revenue requirement for PacifiCorp than if the merger had not occurred." (Merger Condition No. 10). It may be the case that enforcing these conditions requires the Commission to consider additional factors that are not required by the benefits-burdens test.

Q. WHAT IS YOUR RECOMMENDATION?

A. We recommend that the Company's tax expense be adjusted downward by $4.6 million to reflect the burden customers are bearing due to PHI's debt. This method best reflects, based upon currently available information, the burden on customers due to PHI's debt. In addition, a tax adjustment avoids the more time consuming and difficult evaluation of the "hold harmless" Acquisition conditions.

Q. IF THE COMMISSION WANTS TO IMPLEMENT ONE OF THE ALTERNATIVES YOU HAVE OUTLINED, BUT DECLINES TO ADOPT ANY OF THE SPECIFIC DOLLAR ADJUSTMENTS IDENTIFIED BY THE PARTIES, HOW COULD IT DETERMINE THE APPROPRIATE LEVEL OF THE ADJUSTMENT?

A. If the Commission does not wish to adopt any of the estimates put forth by CUB, ICNU, or Staff, the Commission could request that PacifiCorp obtain a study from Standard & Poor's, Moody's, or Fitch and provide the study to the Commission. After the level of adjustment has been determined, the Commission could issue bench requests to determine the changes necessary for rates to reflect the level of adjustment adopted by the Commission.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 170
WITNESS: Bryan Conway
Judy Johnson

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualifications Statement

June 27, 2005

WITNESS QUALIFICATION STATEMENT

NAME: Bryan A. Conway

EMPLOYER: Public Utility Commission of Oregon

TITLE: Program Manager, Economic & Policy Analysis Section

ADDRESS: 550 Capitol Street NE Suite 215, Salem, Oregon 97310.

EDUCATION:

B.S. University of Oregon, Eugene, Oregon
Major: Economics; 1991

M.S. Oregon State University, Corvallis, Oregon
Major: Economics; 1994

In addition, I have completed all of the required and elective coursework for a Ph.D. in economics from Oregon State University. My fields of study were Industrial Organization and Applied Econometrics.

EXPERIENCE: Starting in October 1998, I have been employed by the Public Utility Commission of Oregon. I am currently the Program Manager of the Economic & Policy Analysis Section. My responsibilities include leading research and providing technical support on a wide range of policy issues for electric, telecommunications, and gas utilities. I have testified before the Commission on policy and technical issues in UG 132, UE 115, UE 116, UE 165 and have been the Summary Staff Witness in UP 158, UP 168, UP 165/170, UX 27, UX 28, UM 967, UM 1041, UM 1045, and UM 1121.

From December 1994 to October 1998, I worked for the Oregon Employment Department as a Research Analyst in their Research Section. Duties included leading research projects on various policy issues involving labor economics and information systems.

OTHER EXPERIENCE: I am currently a faculty member of the University of Phoenix teaching graduate and undergraduate economics courses.

From January 1998 through September 2000, I was a part time instructor at Linn-Benton Community College teaching principles of economics.

From July 1992 through June 1994, I was a graduate teaching assistant at Oregon State University teaching introductory principles of economics.

WITNESS QUALIFICATION STATEMENT

NAME:	JUDY A. JOHNSON
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	SENIOR REVENUE REQUIREMENTS ANALYST
ADDRESS:	550 CAPITOL ST. N.E., SALEM, OREGON 97310
EDUCATION:	MBA with an emphasis in Statistics from Eastern Washington University Cheney, Washington BA in Accounting from Eastern Washington University Cheney, Washington

EXPERIENCE:

3/95-Present	I have been employed by the Oregon Public Utility Commission since March of 1995. My primary area of responsibility in my current position has been managing the review of electric and natural gas utility results of operations filings, general rate case filings, deferred accounting applications, and budgets of expenditures.
6/77-2/95	I was employed by Avista Corporation, an electric and natural gas utility located in Spokane, Washington. The majority of my employment was spent in the Rates and Regulatory Affairs Department as a Senior Rate Analyst. I have prepared testimony and exhibits in numerous electric and natural gas rate cases, primarily in the area of results of operations and cost of service.

CASE: UE 170
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Surrebuttal Testimony

June 27, 2005

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Michael Dougherty. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. ARE YOU THE SAME MICHAEL DOUGHERTY WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to update recommended adjustments to PacifiCorp's pension expenses and to provide updated information concerning benefit adjustments described in my direct testimony.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/1101, Pension Expenses.

Q. PLEASE SUMMARIZE YOUR TESTIMONY CONCERNING PENSION EXPENSES.

A. In this testimony, I continue to support the use of PacifiCorp's actual calendar year 2004 FAS 87 and FAS 106 costs (increased by $400,000) instead of using PacifiCorp's revised projected calendar year 2006 FAS 87 and FAS 106 costs. I also continue to support the use of PacifiCorp's actual calendar year 2004 FAS 112 and pension administration costs escalated to calendar year 2006 levels using PacifiCorp's DRI indices.

Q. PLEASE SUMMARIZE YOUR PENSION ADJUSTMENT.

A. The pension expense adjustment consists of four adjustments: FAS 87 pension expense, FAS 106 Postretirement expense, FAS 112 Postemployment expense, and pension administration expenses. I propose the following total adjustments to PacifiCorp's calendar year 2006 test year expenses (Oregon Allocated):

Pension Expense (O&M – 74.63%)	($4,169,730)
Pension Expense (Capital – 24.19%)	($1,351,713)

Q. ARE THESE AMOUNTS DIFFERENT FROM YOUR DIRECT TESTIMONY?

A. Yes.

Q. PLEASE EXPLAIN.

A. There are four changes from my direct testimony. First, I used PacifiCorp's revised calendar year 2006 FAS 87 cost as a basis for my FAS 87 adjustment. Second, I used ICNU's witness, Mr. Selecky's adjustment of reducing the $3 million PacifiCorp contribution to the IBEW 57 Plan by 50 percent to $1.5 million. In my direct testimony, I adjusted for the complete 100 percent reduction. Third, I used PacifiCorp's revised calendar year 2006 FAS 106 costs as a basis for my FAS 106 adjustment. Fourth, I increased the FAS 106 cost by $400,000 to reflect PacifiCorp's Medicare Modernization Act adjustment amount. The result of these changes is that my Oregon allocated O&M adjustment was reduced by $417,538 and Oregon allocated Capital adjustment was reduced by $135,338 from the amounts listed in my direct testimony.

Q. PLEASE EXPLAIN WHY PACIFICORP REVISED ITS PENSION EXPENSE TO $48.4 MILLION?

A. According to PPL 1104; Rosborough/6, PacifiCorp's increased pension expense resulted from PacifiCorp adjusting its discount rate from 6.50 percent in its original projections for 2005 to 5.75 percent in its revised 2005 projections. Also according to PPL 1104; Rosborough/6, this change was made because PacifiCorp's external auditor would not approve a rate above 5.75 percent.

Q. PLEASE REVIEW THE REASONS WHY YOU USED ACTUAL CALENDAR YEAR 2004 FAS 87 COSTS IN YOUR DIRECT TESTIMONY.

A. I used the actual calendar year 2004 cost of $31.5 million for many reasons. First, the 2004 calendar year FAS 87 cost was the most recent full year computation of costs and pursuant to pension rules can be reported as PacifiCorp's fiscal year 2005 FAS 87 cost. Second, the stock market has shown a strong recovery in 2003 and 2004, and short-term interest rates are beginning to rise, which will likely result in less than projected pension costs in 2006 and subsequent years. Finally, the calendar year 2006 costs are based on calculations and estimates (including lower than actual rates of return) that can significantly effect the cost computation of FAS 87 and result in an increased net periodic pension benefit cost.

Q. DID PACIFICORP'S ACTUAL PENSION COSTS INCREASE BY $6.2 MILLION SINCE IT SUBMITTED ITS INITIAL TESTIMONY?

A. No, the $6.2 million change in PacifiCorp's FAS 87 costs from $42.2 million to $48.4 million resulted from lowering the discount rate used in the calendar year 2005 actuarial calculations of the service cost and interest cost components of net periodic pension benefit cost. As I stated in my direct testimony, both the service cost and interest cost are calculations and not actual costs to PacifiCorp.

Q. WHAT IS THE DISCOUNT RATE?

A. The discount rate is the interest rate used for the time value of money. PacifiCorp, through its actuary, calculates its pension obligations by estimating what it will have to pay current and future retirees. Then it discounts this amount back to today's dollars. A lower discount rate will result in an increase of net periodic pension benefit costs, while a higher discount rate will result in a decrease of net periodic pension benefit costs.

Q. SO A LOWER DISCOUNT RATE WILL RESULT IN INCREASED ACTUARIAL (CALCULATED) COSTS?

A. Yes. A lower discount rate will result in an increase of FAS 87 net periodic pension benefit costs. For pension purposes, a company's discount rate should reflect the interest rate of high-quality corporate bonds that have maturities that match the expected payments to retirees.[1] Although bond yields will vary throughout the year, the discount rate used in the actuarial assumptions will stay constant during the year.

Q. DOES PACIFICORP HAVE REASONS TO BELIEVE THAT BOND YIELDS WILL STAY LOW DURING 2005 AND AT THE LEVEL OF PACIFICORP'S 5.75 PERCENT DISCOUNT RATE?

A. No. Although Staff does not support Dr. Hadaway's testimony, in PPL/207; Hadaway/1, Dr. Hadaway demonstrates that Moody's average public utility

[1] Wall Street Journal, *Heard on the Street: Gloom lifting for pension plans,* Cassell Bryan Low, Friday, August 15, 2003.

bond yield was 6.20 percent in 2004. Also in PPL 208; Hadaway/1, Dr. Hadaway uses the April 22, 2005, Standards & Poor's, "Trends & Projections" to support a projected single-"A" corporate bond rate of 6.7 percent for 2005. Both these examples demonstrate that PacifiCorp expects bond rates to be higher than PacifiCorp's 5.75 percent discount rate used to calculate the 2005 FAS 87 cost. As previously mentioned, the discount rate should reflect the interest rate of high-quality corporate bonds that have maturities that match the expected payments to retirees.

Q. IN YOUR DIRECT TESTIMONY DID YOU SUPPORT PACIFICORP'S USE OF 5.75 PERCENT?

A. No. In my direct testimony, I supported the use of PacifiCorp's revised discount rate of 6.0 percent. This was the discount rate PacifiCorp used and supported in Data Request No. 301. In the response to the Data Request, PacifiCorp substituted the actual 2004 rate of return on Plan assets of 10.5 percent and 2005 expected long-term rate of return of 8.75 percent for the actuarial assumptions of 4.0 percent and 8.0 percent return on market value of Plan assets initially used as inputs for calculating the calendar year 2006 FAS 87 costs.

Q. WHAT WAS THE RESULT OF THIS SUBSTITUTION?

A. The substituted numbers had a significant effect on the *"Impact of estimated favorable asset return during CY 2004 and continued recognition of deferred asset losses"* by decreasing the pension benefit cost of this input from $9.2 million to $3 million in calendar year 2005; and decreasing the pension benefit cost of this input from $5.2 million to $1.8 million in calendar year 2006. This results in a combined reduction of $9.6 million dollars. When this combined reduction of $9.6 million is subtracted from PacifiCorp's initial projected calendar year 2006 FAS 87 cost of $42.2 million, the result is $32.6 million. The $32.6 million result using a discount rate of 6.0 percent is close to the calendar year 2004 FAS 87 cost of $31.5 million.

Q. IN PPL/104; ROSBOROUGH/6, PACIFICORP STATES THAT IT USED THE ACTUAL 2004 RATE OF RETURN IN ITS REVISED CALCULATIONS TO DETERMINE THE PROJECTED COSTS OF $48.4 MILLION. HOW DOES THIS AMOUNT DIFFER FROM THE RESPONSE PACIFICORP PROVIDED FOR STAFF DATA REQUEST NO. 301?

A. The two results are significantly different; however, in response to Staff Data Request No. 301, PacifiCorp had already changed its discount rate to 6.0 percent in the calculation. In other words, PacifiCorp had already recognized a 50 basis point lowering of the discount rate from the initial 6.50 percent. The pension calculations include multiple variables and estimates. Any combination of changes in the cost calculation can significantly alter the final result.

Q. YOU MENTIONED THAT YOU USED CALENDAR YEAR 2004 FAS 87 COST FOR MANY REASONS; CAN YOU PLEASE PROVIDE SUPPORT FOR EACH REASON?

A. Yes, the first reason was that the 2004 calendar year FAS 87 cost was the most recent full year computation of costs, and pursuant to pension rules, can be reported by PacifiCorp as its fiscal year 2005 FAS 87 cost. Since my direct testimony, PacifiCorp submitted its fiscal year 2005 FAS 87 net periodic pension benefit cost as reported on its SEC Form 10-K for the fiscal year ending March 31, 2005.

Q. WHAT NET PERIODIC PENSION BENEFIT COSTS DID PACIFICORP RECORD IN ITS SEC FORM 10-K FOR THE FISCAL YEAR ENDED MARCH 31, 2005?

A. For the fiscal year ending March 31, 2005, PacifiCorp recorded a net periodic pension benefit cost of $40.3 million. Although this amount is higher than the calendar year 2004 cost of $31.5 million, the calculation of this cost included an expected return on Plan assets of $77.7 million.

Q. HOW DID THE EXPECTED RETURN ON PLAN ASSETS COMPARE TO PACIFICORP'S ACTUAL RETURN ON PLAN ASSETS?

A. According to page 99 of PacifiCorp's SEC Form 10-K[2], actual return on Plan assets was $87.5 million. This actual return is significant in many ways. First, it is $9.8 million higher than the expected return on Plan assets. This difference demonstrates the variance between actuarial calculations and actual results and supports my recommendation of $31.5 million for pension costs. Second, the actual return on Plan assets demonstrates that PacifiCorp used a low estimated rate of return on plan assets in its actuarial calculations.

[2] PacifiCorp's SEC Form 10-K, as of March 31, 2005.

PacifiCorp's actual return was 12.6 percent greater than its expected return.[3] Third, the actual return on plan assets was $8.3 million greater than the benefits paid in fiscal year 2005, which was $79.2 million. In essence, the PacifiCorp Plan returned sufficient funds to fully fund the fiscal year 2005 pensions paid to PacifiCorp's retirees.

Q. PLEASE PROVIDE YOUR SUPPORT THAT THE STOCK MARKET HAS SHOWN A STRONG RECOVERY IN 2003 AND 2004, AND INTEREST RATES ARE BEGINNING TO RISE, WHICH WILL LIKELY RESULT IN LESS THAN PROJECTED ACTUAL COSTS IN 2006 AND SUBSEQUENT YEARS.

A. The Dow Jones Industrial Average (DJIA) has increased approximately 1,712 points over the time period beginning April 2003 (8,840) through April 2005 (10,192).[4] This is a 15.3 percent increase over the two-year time period. Additionally, the DJIA has continued to increase achieving 10,523 as of June 13, 2005.[5] This increase in the equity markets is significant for PacifiCorp since 56.1 percent of PacifiCorp's Plan in fiscal year 2005 was invested in equity securities.[6] Short-term interest rates are also beginning to increase. An example of increasing interest rates is that the effective Federal Fund Rate has increased from 2.28 percent in January 2005 to 3.0 percent in May 2005.[7]

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[3] PacifiCorp's actual return of 12.6 percent over expected returns is following national trends. Per a Milliman Inc. 2004 Pension Fund Survey, average actual investment return on pension assets for 2004 was 12.4 percent in excess of expected rates of return. *www.Milliman.com.*
[4] Dow Jones Industrial Average Stock Index Monthly Values (Last Trading Day of the Month)
[5] I do note that the stock market as of June 14, 2005, is below the December 31, 2004, close.
[6] PacifiCorp's SEC Form 10-K, as of March 31, 2005.
[7] Board of Governors of the Federal Reserve System.

Q. DOES PACIFICORP SUPPORT YOUR ASSERTION THAT INTEREST RATES WILL INCREASE IN 2005?

A. Yes. In both direct and rebuttal testimony, PacifiCorp makes a case that interest rates will increase. Dr. Hadaway provided an excerpt from Standard & Poor's supporting his assertion of higher interest rates at PPL/200; Hadaway/18 and 19 by stating: (emphasis added)

> "The GDP growth rate compares to a rates of less than 2 percent in 2001 and 2.4 percent for 2002. Consistent with these improving economic conditions, S&P also forecasts unemployment below 5.5 percent and *that interest rates will rise an additional 80 to 100 basis points (0.8% to 1.0%) from current levels.*"

Additionally, D. Douglas Larson at PPL/1700; Larson/9 and 10 states: (emphasis added)

> "Yes, interest rates are rising….After falling for three years, the bellwether Federal Funds interest rate rose for most of 2004 and continues to rise in 2005. As discussed in Dr. Hadaway's rebuttal testimony, *interest rates for corporate bonds are projected to increase in 2006*."

Based on PacifiCorp's assertions that interest rates will rise in 2005 and 2006, and because PacifiCorp's discount rate should reflect the interest rate of high-quality corporate bonds that have maturities that match the expected payments to retirees, PacifiCorp's use of a 5.75 percent discount rate is low, which results in increased calculated costs for the calendar year 2005 FAS 87 cost.

Q. YOU STATE THE DISCOUNT RATE IS LOW, BUT PACIFICORP STATED THAT ITS EXTERNAL AUDITOR REQUIRED THIS RATE.

A. In the reference I included in direct testimony, PacifiCorp's independent auditor, Price Waterhouse Coopers (PWC) recommended that discount rates should generally not exceed 5.75 percent.[8] In fact, PWC states: (emphasis added)

> "As always been the case, engagement teams should ensure, as part of the audit *that clients have adequate, documented support for the assumptions they used in measuring pensions and OPEB*…"[9]

Additionally, in a January 16, 2005, e-mail to PacifiCorp from its actuary, Mr. Kopec of Hewitt, PacifiCorp's actuary points out that thirteen of Hewitt's clients are at 6.0 percent, while nineteen are at 5.75 percent. It is interesting to note that the e-mail states: (emphasis added)

> "We have 36 clients with 12/31 measurement dates *who have made final decisions* for their FAS 87 discount rate."[10]

Also in PPL/1500; Kopec/2, Mr. Kopec states: (emphasis added)

> "Although *PacifiCorp ultimately sets the economic assumptions for the calculation in accordance with the FASB guidelines*, the assumptions must be agreed upon and approved by the company's auditor which in this case, is Price Waterhouse Coopers."

These references demonstrate that PacifiCorp has influence on the discount rate selected. Based on PacifiCorp's statements about interest rates for corporate bonds, sufficient documentation by PacifiCorp to support a 6.0 percent discount rate could be demonstrated. If PacifiCorp takes a passive approach about the assumptions used in its Plan, which has a fair value of

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[8] Price Waterhouse Coopers R&Q Alert Number 05/09.
[9] *Ibid.*
[10] Hewitt Survey Results for clients with 12/31 measurement dates.

assets of $806.5 million[11], customers should not be required to bear the additional expense that results from a general policy of a third-party auditor. FAS 87 actually states that requiring all employers to use the same assumptions is inappropriate.[12]

Q. ALTHOUGH YOU PRESENT REASONS WHY PACIFICORP COULD HAVE USED A HIGHER DISCOUNT RATE IN ITS CALCULATIONS, THE FACT IS THAT PACIFICORP USED A 5.75 PERCENT DISCOUNT RATE AND THIS RATE WAS APPROVED BY BOTH PACIFICORP'S ACTUARY AND EXTERNAL AUDITOR. WHY SHOULD THE COMMISSION NOT ADOPT A FAS 87 COST THAT USES THIS DISCOUNT RATE?

A. The Commission should not adopt a FAS 87 cost based on PacifiCorp's revised discount rate. PacifiCorp decreased the discount rate by 75 basis points from its initial testimony based on economic assumptions, yet PacifiCorp is also presenting cost of capital testimony demonstrating that these economic assumptions are improving. The discount rate is one of many assumptions used in the FAS 87 calculation, and customers should not be required to pay for calculated pension costs using recent, historically low assumptions for the discount rate, especially since PacifiCorp's Plan returned sufficient funds to cover actual payments to retirees.

Q. PLEASE PROVIDE YOUR SUPPORT THAT THE CALENDAR YEAR 2006 COSTS ARE BASED ON CALCULATIONS AND ESTIMATES (INCLUDING LOWER THAN ACTUAL RATES OF RETURN) THAT CAN

[11] PacifiCorp's SEC Form 10-K, as of March 31, 2005.
[12] FAS 87, Employers' Accounting for Pensions, paragraph 193.

SIGNIFICANTLY EFFECT THE COST COMPUTATION OF FAS 87 AND RESULT IN AN INCREASED NET PERIODIC PENSION BENEFIT COST.

A. As previously mentioned, PacifiCorp's actual return on Plan assets of $87.5 million for the fiscal year ending March 31, 2005, was $9.8 million higher than its expected return and $8.3 million greater than actual benefits paid. In the fiscal year ending March 31, 2004, PacifiCorp's actual return on Plan assets was $128.3 million, which was $47.6 million higher than its expected return and $15.4 million greater than actual benefits paid.[13] Although PacifiCorp's Plan experienced losses in 2003 and 2002, these losses are being amortized by PacifiCorp in the Amortization of unrecognized loss component of net periodic pension benefit costs. However, the recent significant gains over the past two fiscal years of 2004 and 2005 lessen the effect of the losses in 2003 and 2002.

Q. DO YOU AGREE WITH PACIFICORP THAT USING THE ACTUAL CALENDAR YEAR 2004 COST WILL PERPETUATE THE REGULATORY LAG AND FURTHER EXACERBATE PACIFICORP'S UNDER-RECOVERY OF ITS FAS 87 COST?

A. No. As I previously noted, actual returns on PacifiCorp's Plan have exceeded payments to retirees the past two years, so an under-recovery of costs did not occur.

Q. WHAT OTHER INFORMATION IN YOUR DIRECT TESTIMONY SUPPORTS YOUR RECOMMENDED FAS 87 COST OF $31.5 MILLION?

A. In my direct testimony, I state in Staff/400; Dougherty/15 that:

[13] PacifiCorp's SEC Form 10-K, as of March 31, 2005.

> "It is interesting to note that although contributions have been high in the previous few years, the five-year average of contributions is $31.68 million, extremely close to the calendar year 2004 FAS 87 cost of $31.5 million. Additionally, when examining Table 1, PacifiCorp' five-year average FAS 87 cost was $26.32 million and ten-year FAS 87 average cost was $29.29 million. Both these average costs are lower, but within a range of the calendar year 2004 FAS 87 net periodic pension benefit cost."

When all the information on past costs, current short-term interest rates, and performance of the equity markets is considered cumulatively, my recommendation of $31.5 million more reasonably reflects the costs that PacifiCorp will actually bear in calendar year 2006, especially considering earnings on the Plan have fully covered benefits paid in the last two years. This trend of increased returns is likely to continue based upon the recent performance of the equity markets. Additionally, actual benefits paid by PacifiCorp have shown a steady decrease from $129.6 million in fiscal year 2002 to $79.2 million in fiscal year 2005. If the trends of increasing market performance and decreasing costs persist, PacifiCorp's funded status of its Plan will continue to grow resulting in actuarial calculations that reflect lower FAS 87 net periodic pension benefit costs. As a result, the calendar year 2005 actuarial calculated cost is not a fair and accurate proxy in ratemaking for pension costs incurred by PacifiCorp for calendar year 2006 and subsequent years. The Commission should use the calendar year 2004 actual FAS 87 cost of $31.5 million.

Q. DO YOU AGREE WITH PACIFICORP'S ADDITION OF $3.0 MILLION FOR CONTRIBUTIONS TO THE IBEW 57 TRUST FUND?

A. No, however, I can support ICNU's witness, Mr. Selecky's adjustment of reducing the $3 million PacifiCorp contribution to the IBEW 57 Plan by 50 percent to $1.5 million to reflect that PacifiCorp did not make a contribution to the IBEW 57 Plan in 2005, but could possibly make a contribution in 2006.

Q. PLEASE REVIEW YOU REASONS WHY YOU USED ACTUAL CALENDAR YEAR 2004 FAS 106 COST IN YOUR DIRECT TESTIMONY.

A. I used actual calendar year 2004 cost of $21 million for many reasons. First, the 2004 calendar year FAS 106 cost was the most recent full year computation of costs and pursuant to pension rules can be reported as PacifiCorp's fiscal year 2005 FAS 106 cost. Second, the stock market has shown a strong recovery in 2003 and 2004, and short-term interest rates are beginning to rise, which will likely result in less than projected actual costs in 2006 and subsequent years. Finally, the calendar year 2006 costs are based on calculations and estimates (including lower than actual rates of return) that can significantly effect the cost computation of FAS 106 and result in an increased net periodic postretirement benefit cost.

Q. DO YOU SUPPORT PACIFICORP'S DECREASE OF PROJECTED CALENDAR YEAR 2006 FAS 106 COSTS FROM $26.8 MILLION TO $24.1 MILLION?

A. No. I agree with PacifiCorp that the $26.8 million projection does not take into account the full savings resulting from the Medicare Modernization Act, but do not agree that the correct level is $24.1 million. However, I can support a level of $21.4 million, an increase of $400,000 from my direct testimony.

Q. WHY IS PACIFICORP'S PROJECTED $24.1 MILLION FAS 106 COST HIGHER THAN YOUR RECOMMENDED AMOUNT?

A. It is higher because PacifiCorp added $2.7 million in increased benefits due to a Plan amendment. In PPL/1104; Rosborough/11, Mr. Rosborough states:

> "The Company's 2005 FAS 106 expenses also include an increase in expense of $2.7 million related to a Plan amendment made in March 2005. The amendment increases the amount the Company contributes toward the cost of retiree medical coverage for employees who retired after 1990 but before 2007."

This increase is not consistent with national trends concerning retiree health benefits. Although the "legacy" cost increases for the American automobile and airline industries are well-documented, other industries are also faced with the rising costs of retiree health care and have made changes to their respective plans to mitigate these costs. According to Watson Wyatt:[14]

> "Today's trend away from employer-provided health benefits is certain to continue, thanks to rising health care costs, growing retiree populations, uncertain business profitability and federal regulations that discourage employers from prefunding retiree medical benefits. The benefits provided to future retirees will be much less generous than those received by current retirees as employers cut back, cap or completely eliminate their retiree health benefits programs. Eight out of 10 employers that still offered retiree medical benefits in 1999 had reduced their retiree medical expense per active employee from the level reported for 1993, according to Watson Wyatt research."[15]

The Watson Wyatt article continues to state:

[14] Watson Wyatt, according to its web-site, is a global consulting firm focused on human capital and financial management that specializes in four areas: employee benefits, human capital strategies, technology solutions and insurance and financial services.
[15] Watson Wyatt Insider, *Retiree Health Benefits: Time to Resuscitate?*

> "Employers needed to contain the rising liabilities from their retiree medical programs, and one way was to simply shut them down. Twenty percent of large employers with retiree health plans have already eliminated their retiree medical plan for new hires, and another 17 percent have virtually eliminated their retiree health liabilities for new hires by requiring them to pay the full premium."[16]

The Watson Wyatt information is substantiated by a survey conducted by the Kaiser Family Foundation and Hewitt.[17] The survey includes changes made by large employers for retiree health benefits in 2003 and states:

> "Employers offering retiree health benefits have made substantial changes in recent years in an effort to control rising costs, and all signs point to sustained efforts to slow the growth in retiree health obligations in the future."[18]

These references indicate that by amending its plan to increase benefits, PacifiCorp is not following national trends, resulting in customers paying a premium for PacifiCorp's retiree health benefits.

Q. CAN YOU PLEASE REVIEW THE ADJUSTMENTS YOU MADE TO THE FAS 106 COST?

A. Yes. I subtracted $2.7 million, which is the cost of the amended Plan, from PacifiCorp's revised 2005 expense of $24.1 million resulting in $21.4 million. Although this amount is higher than the calendar year 2004 cost in my direct testimony, it is reasonable because of the updated information on savings associated with the Medicare Modernization Act.

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[16] *Ibid.*
[17] Hewitt is PacifiCorp's actuary.
[18] *Retiree Health Benefits, Now and in the Future. Findings from the Kaiser/Hewitt 2003 Survey on Retiree Heath Benefits*, January 2004.

Q. DID YOU MAKE ANY CHANGES TO YOUR RECOMMENDED FAS 112 COST?

A. No.

Q. DID PACIFICORP SPECIFICALLY ADDRESS THE FAS 112 ADJUSTMENT IN ITS REBUTTAL TESTIMONY?

A. No.

Q. DID YOU MAKE ANY CHANGES TO YOUR RECOMMENDED PENSION ADMINISTRATION COSTS?

A. No.

Q. DID PACIFICORP SPECIFICALLY ADDRESS THIS ADJUSTMENT IN ITS REBUTTAL TESTIMONY?

A. No.

Q. WERE THERE ANY CHANGES FROM YOUR DIRECT TESTIMONY CONCERNING ADJUSTMENTS TO PACIFICORP'S BENEFIT COSTS?

A. Yes.

Q. PLEASE EXPLAIN.

A. Staff, PacifiCorp, CUB, and ICNU agreed on a settlement position concerning my initial benefit adjustment. In the UE 170, Second Partial Stipulation, the parties agreed to a $2.44 million reduction in the Company's filed revenue requirement for employee benefits.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

CASE: UE 170
WITNESS: Michael Dougherty

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Exhibit in Support of
Surrebuttal Testimony
Adjustments to Pension Expenses

June 27, 2005

PacifiCorp Pension Adjustments

	PacifiCorp System	Staff System	System Adjustment	PacifiCorp Oregon	Staff Oregon	Oregon Adjustment
Pension Expense (Per PPL Rebuttal Testimony)	$48,400,000	$33,000,000	$15,400,000	$14,251,961	$9,717,246	$4,534,715
Other Pension Expenses						
Pension Administration (CY 2004 expense escalated to CY 2006)	$1,279,098	$1,016,044	$263,054	$376,646	$299,186	$77,460
Retirement Allowance (CY 2006 expense, PPL Exhibit 801, 4.18, Page 27)	$291,611	$291,611	$0	$85,868	$85,868	$0
FAS 106 Benefit (Per PPL Rebuttal Testimony)	$24,100,000	$21,400,000	$2,700,000	$7,096,534	$6,301,487	$795,047
FAS 112 Benefit (Per PPL Response to DR #339)	$6,806,250	$5,699,303	$1,106,947	$2,004,182	$1,678,228	$325,954
Total Pension Expense	**$80,876,959**	**$61,406,958**	**$19,470,001**	**$23,815,191**	**$18,082,016**	**$5,733,176**
OMAG - 74.63%	$59,988,516	$45,828,013	$14,160,503	$17,664,338	$13,494,608	$4,169,730
Capital - 24.19%	$19,444,793	$14,854,343	$4,590,450	$5,725,753	$4,374,040	$1,351,713

Pension (FAS 87) Expense - Staff used PacifiCorp's calendar year 2004 cost of $31.5 million and added $1.5 million for contributions to the IBEW 57 Trust Fund (50 percent of $3 million).

Postretirement (FAS 106) Expense - Adjusted based on PacifiCorp's revised numbers.

CASE: UE 170
WITNESS: MORGAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Surrebuttal Testimony

<u>Redacted Version</u>

June 27, 2005

CERTAIN INFORMATION CONTAINED IN STAFF

EXHIBIT 1200 IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 04-682.

YOU MUST HAVE SIGNED THE PROTECTIVE ORDER

IN DOCKET UE 170 TO

RECEIVE THE CONFIDENTIAL PORTION OF THIS EXHIBIT.

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. This testimony responds to claims made by the Company's witnesses pertaining to cost of equity, capital structure and financial integrity.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes. I prepared Exhibit Staff/1201, consisting of 48 pages.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

INVESTMENT REQUIREMENTS IMPACT ON COST OF CAPITAL

Q. SHOULD PACIFICORP EXPECT TO PAY A HIGHER RETURN BASED ON ITS EXPECTED CAPITAL REQUIREMENTS?

A. No. PacifiCorp represents that it "must expect to pay a higher return to meet future new capital requirements than it has paid in the most recent past." (*See* PPL/1700 Larson/10)

This discussion ignores the reality that interest rates are now at their lowest levels in decades. In order to fund capital requirements, the Company would likely issue debt and equity, in order to balance its capital structure, as determined by its Board of Directors. The Company would not pay higher rates of interest solely because of its capital expansion program. Lastly, Dr. Hadaway has not addressed this facet in his cost of equity testimony and it is difficult to understand the basis of this unsupported argument.

GROWTH RATE

Q. IS THE GROWTH RATE ISSUE THE BIGGEST AREA OF DISAGREEMENT"?

A. Yes. The "perpetual growth" estimation is the most important matter in this docket. To be well-informed about the long-run, "perpetual growth" estimation, historic growth rates among rate-regulated operations should be considered, in conjunction with other tools, in order to develop reasonable estimates about future growth. My analysis demonstrates that growth rates will not approach any figure near Dr. Hadaway's historic GDP calculation.

Q. ARE THE GROWTH RATES YOU USED IN YOUR ANALYSIS "SHORT-TERM" AS ALLEGED BY DR. HADAWAY?

A. No. Dr. Hadaway implies that the growth rates that have been included in the analyses by both Mr. Gorman and me are "short-term". (*See* PPL/205Hadaway/6, at 2)

In his discussion, Dr. Hadaway references my growth rates as being "based on only near-term data and low inflation forecasts" as being incorrect. (*See* PPL/205 Hadaway/15, 7-9) Dr. Hadaway mischaracterizes my analysis and supporting testimony. My opening testimony contains a detailed discussion of factors that underlie growth, among public electric utilities, in the long-run. Those factors include expected rates of return and retention rates. My recommendations regarding growth do not rely on "short-term" rates.

Q. WOULD DR. HADAWAY'S FORECAST OF GROWTH IN PACIFICORP'S LAST CONTESTED RATE CASE BE USEFUL IN THIS CASE?

A. No. Dr. Hadaway indicates that his growth forecasts, from PacifiCorp's rate case, UE 116, in 2000, would be the proper "fix" to both Mr. Gorman's and my analyses. He did not develop the models to support this contention, so it is difficult to respond to this claim.

In PacifiCorp's last rate case, UE 147, Dr. Hadaway estimated growth at 5.86 percent, which would reflect a decrease of 74 basis points, if he were to use this growth rate today. That rate case also has a capital structure proposal consisting of only 45 percent common equity versus PacifiCorp's current request of 49.6 percent common equity. The interaction of these two variables was not discussed by Dr. Hadaway, nor did he respond to the considerable impact of the tax cut that I discussed at Staff/200 Morgan/64, which decreased the cost of equity for regulated utilities. (*See* Staff/1201 Morgan/5, Edison Electric Institute's Electric Perspectives "The Dividend Advantage") The example provided in this article indicated a decrease in the cost of equity of 150 basis points, or 1.50 percent reduction in the cost of equity.

If one were to assume that the tax change decreased the cost of equity by only 50 basis points, and the growth rate assumed by Dr. Hadaway in UE 147 were applied today, his recommendation of 11.125 percent would be 9.89 percent. (11.125% - .50% - .74% = 9.89%)

Q. ARE HISTORIC GROWTH RATES RELEVANT WHEN CONSIDERING THE GROWTH RATE FOR THE DCF MODEL?

A. Yes. A company's level of growth is based on consideration of (1) its asset base, and (2) its earnings on that base. Past results provide an initial starting point in an analysis. Dr. Hadaway uses his historic 40-year GDP growth rate to project the future growth for the regulated electric utility industry without providing any theoretical or analytical support. Instead of considering such a broad measure of growth, my analysis used the more pertinent recent results of the industry itself. This is a more reasonable approach. I then used available market information, including retention rates, ROEs, and market consensus rates when considering my final conclusions.

Unlike my analysis, Dr. Hadaway did not consider actual, recent growth rates among the sample group of companies that he considers. He indicates that, "long-term growth expectations…should not change greatly from year to year." (*See* PPL/205 Hadaway/6, 14-16) However, the industry has not achieved the level of growth that he has forecast over the past several years. At Staff/203 Morgan/16, I provided evidence of historic growth rates among the ample group of companies Dr. Hadaway identified in his opening testimony. Historic growth rates have been lower than five percent. (*See* Staff/203 Morgan/17) The issue of "convergence" directly revolves around the requirement that the underlying fundamentals must have basis in actual results. I discuss this issue later in my testimony.

Q. ARE GROWTH RATES DIRECTLY "PLUGGED" INTO EACH DCF MODEL?

A. No. In my 40-year DCF Model, the growth rate is not a direct input into the model. The model provides a direct link among asset values, retention rates and ROEs.

Q. WHY IS HISTORIC GROWTH IN THE GROSS DOMESTIC PRODUCT (GDP) NOT APPROPRIATE FOR USE IN THE DCF MODEL?

A. Even though GDP (or GDP per capita[1]) may provide a proxy for growth in the market, overall, I am not aware of any source that indicates that GDP growth is a reasonable expectation for public utilities.

Dr. Hadaway failed to address the relationship among GDP and growth rates for public utilities. He offered no evidence to support such a relationship. Measurements from the past movements in the economy overall are of such a general nature that they cannot be applied to public utilities.

In my opening testimony, I argued that there is theoretical support why public utilities should actually grow slower than the economy. Forward-looking growth rates are superior to historic growth rates, when viewed in isolation. The Commission addressed this issue in UG 132, which is discussed below.

Q. DOES DR. HADAWAY'S TESTIMONY SUPPORT HIS USE OF HISTORIC GDP GROWTH?

A. No. Dr. Hadaway failed to address my discussion of his misuse of historic GDP as a proxy for growth. (*See* Staff/200 Morgan/26) If the Commission decides to adopt GDP growth forecasts, it should rely on ex ante (forward-looking) GDP figures. I provided such forecasts. (*See* Staff/200 Morgan/51; Staff/202 Morgan/2-3; Staff/202 Morgan/227-228; Staff/202 Morgan/370-372)

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[1] At Staff/1201 Morgan/17-28, I provide an excerpt of a report of economists who attended the 2002 Equity Risk Premium Forum, sponsored by the Association for Investment Management and Research (AIMR). The AIMR offers the Chartered Financial Analyst (CFA) designation. The complete report is available on the Internet at: http://www.aimrpubs.org/ap/issues/v2002n1/toc.html
In this report, GDP per capita is used as a proxy for economy-wide growth. This is contrary to Dr. Hadaway's use of historic nominal GDP, in aggregate.

The Company also provided estimates of inflation-adjusted GDP growth, pursuant to staff Data Request 110. This information is from Global Insight. (*See* Staff/1201 Morgan/32)

Historic GDP growth rates are inferior to forward-looking growth rates. This is especially true over long periods of time that contained inflationary pressures that are not anticipated over the foreseeable future.

Dr. Hadaway has not provided evidence to support long term growth rates for regulated public utilities approaching 6.6 percent. Dr. Hadaway also failed to address whether forward-looking GDP growth is superior to historic growth rates, assuming that it were the appropriate proxy for public utilities.

In UG/152, Dr. Hadaway quoted a prior Commission statement indicating its preference for forecasted as opposed to historical growth rates:

> "We agree that forward-looking projections should be used, if available. There is evidence in this record that forecasts of earnings growth provide superior estimates of DCF growth than historical measures, such as past BR, EPS, or DPS growth." (*See* Docket UG 132, Order No. 99-697, at 18.)

It should be noted that in UG 132, the Commission used forward-looking growth rates based on analyst estimates, expected reinvestment rates and expected earnings rates, as I have.

<u>GDP GROWTH RATE AND ECONOMY-WIDE GROWTH</u>

At PPL/205, Hadaway/14, Dr. Hadaway includes excerpts from an article where he draws the conclusion that, because GDP growth may approximate overall corporate earnings growth, somehow it is the proper growth rate for public utilities. He omits any discussion about whether he should use ex ante forecasts. I provided several sources of forward-looking GDP growth and they range from roughly five to six percent, depending on assumptions about inflation. As stated in my opening testimony, if the Commission uses GDP as a proxy for growth, it should be based on a future-oriented analysis, and it should be tempered to reflect the relationship between public utility growth and economy-wide growth. (*See* Staff/200 Morgan/56) However, industry-specific growth rates are still superior.

Finally, the articles cited by Dr. Hadaway show only that GDP (or GDP per capita) may roughly approximate the market's *overall* growth. The articles do not show that GDP is useful for a specific industry or sector and they do not support Dr. Hadaway's use of historic GDP growth in his DCF models.

Q. PLEASE CALCULATE THE FUNDAMENTAL GROWTH FORMULA ('B X R') THAT WOULD SUPPORT DR. HADAWAY'S GROWTH POSITION.

A. Using a 40 percent "reinvestment rate," the sample of companies would have to generate a perpetual 16.50 percent ROE[2] in order to achieve growth of 6.6 percent per year that Dr. Hadaway estimates. Dr. Hadaway's DCF analysis reflects a reinvestment rate of only 32.81 percent and an ROE of only 10.9 percent. (*See* PPL/206 Hadaway/2). Using his 32.81 percent reinvestment rate would require a perpetual ROE of over 20 percent. (6.60% / 32.81% = 20.12%)

[2] 6.60% / .40% = 16.50%. This is derived through the sustainable growth rate formula (or, "b x r".) See Staff/200 Moirgan/29-30.

The figures he uses in his DCF analysis are more reasonable than the figures that would be necessary to support a 6.6 percent growth rate. However, he throws out the results of his analysis because they are "not consistent with consensus economic projections for higher interest rates." (*See* PPL/200 Hadaway/23, Lines 7-8) Based on reasonable estimates of retention rates and ROEs, Dr. Hadaway's 6.6 percent growth rate result cannot reasonably be anticipated by investors.

Q. WHAT DID DR. HADAWAY'S DCF ANALYSIS REFLECT?

A. Using a 6.6 percent calculation of historic growth, and ignoring analyst estimates and the "b x r" sustainable growth rate calculation, Dr. Hadaway's DCF recommendation is 10.9 percent.

Q. DOES THE 11.50 PERCENT ROE FORECAST FROM VALUE LINE ASSUME THAT REGULATED UTILITIES SHOULD BE GRANTED ROES IN THAT RANGE?

A. No. Dr. Hadaway informs us of Value Line's current "forecast" of 11.50 percent ROEs, however, he does not mention why this may not be appropriate.

First of all, Value Line covers a total of 61 electric companies throughout the US. (*See* Staff/1201/Morgan/14) These companies are not all predominantly rate-regulated. In fact, of these companies, Dr. Hadaway included only sixteen in his initial "cohort" sample (and 17 in his updated sample.) This group was represented as being a "close fit" to purely rate-regulated enterprises. Therefore, there are 44 additional companies making up the Value Line universe that were filtered as not being predominantly rate-regulated.

The impact of unregulated operations and investments clearly impacts the equity returns that are expected to be earned from these companies. This information does not support a requirement of such high equity returns for purely rate-regulated operations. Given the calculations I provided above, a perpetual growth rate of 6.6 percent is unlikely even for the entire universe of companies covered by Value Line.

Q. SHOULD THE PERPETUAL GROWTH RATES VARY YEAR BY YEAR?

A. The growth rates over the short term, the intermediate term and the long-term would likely vary somewhat, although the "perpetual growth" used in a DCF model should remain reasonably stable in the DCF model, within reasonable bounds.

Although Dr. Hadaway states that his conclusion regarding growth is near the rate he projected in docket UE 116, he does not disclose the actual average growth rates among public utility companies since UE 116. Simply maintaining consistent ROE analyses, over time, does not necessarily indicate that the analyses include the proper assumptions.

Q. WHAT IS THE GROWTH RATE ANTICIPATED BY PACIFICORP IN ITS INTERNAL FINANCIAL MODELS?

A. PacifiCorp's own average earnings growth rate forecast is only **[CONFIDENTIAL/]** [redacted] **[/CONFIDENTIAL]** over approximately the next decade. This is consistent with my growth rate assumptions and calculations. (*See* Staff/1201 Morgan/35)

DEBT EQUIVALENTS

Q. HOW SHOULD THE COMMISSION CONSIDER THE IMPACT OF "DEBT EQUIVALENTS"?

A. Dr. Hadaway criticizes the financial metrics proffered by Mr. Gordon. Dr. Hadaway indicates that the metrics do not include the impact of $500 million in "debt equivalents" that Dr. Hadaway states the S&P's credit rating analysis "requires to be included in its bond rating metrics." Not only did Dr. Hadaway neglect to provide the supporting figures, but he also did not address the fact that it is extremely common for companies to be impacted by these "off-board" adjustments by S&P.

It is not clear exactly how each of Dr. Hadaway's comparable companies is impacted by these same factors. Nor did Dr. Hadaway provide information pertaining to the correlation among off-balance sheet items to actual credit ratings. The sample selection process should consider pertinent factors, such as the use of PPAs. I have accepted Dr. Hadaway's sample as reasonable and the Company has not argued that the sample is not reasonable.

CREDIT METRICS AND CREDIT RATINGS

Q. ARE THE CREDIT RATING METRICS GOOD IDENTIFIERS OF WHERE THE ROE SHOULD BE SET?

A. No. First, PacifiCorp has not included the underlying data supporting its on-going credit metrics. (*See* PPL/304 Williams/19) Further, credit ratings are not set based on a single year's expectations. Not only do credit rating analysts take a more macro view of the industry, they also consider metrics over several years.

The metrics that are published by S&P are not “predictive” but provide the benchmarks for the companies that rating agencies follow. (*See* Staff/1201 Morgan/1) If a company falls outside the range on one or more of the statistics, it is not necessarily downgraded.

The difficulty in calculating the financial metrics is that there is a wide array of metrics. Additionally, there is interplay among different factors. Credit ratings are not as simple as generalized mathematical formulas. Because the cost of equity is the rate applied to the rate base assets, it is not unreasonable to consider credit metrics for those assets alone, as Mr. Gorman did.

Q. DO CREDIT RATINGS DETERMINE A COMPANY’S ABILITY TO ACCESS THE CAPITAL MARKETS?

A. No. A company’s ability to attract capital is not limited to the consideration of only debt ratings. As long as a company has a solid investment-grade rating, there is no reason to assume that the capital attraction standard is not met. It would not be appropriate to attempt to set the cost of capital based on the maintenance of any specific credit rating category.

There is no way to predict the actual actions of the rating agencies, and surmising that we have an ability to actually mirror the analysis of the credit rating agencies is misguided. Still, considering the current marginal cost of debt for PacifiCorp of around 4.7 percent (*See* Staff/1300 Peng/5, line 14) even a notch downgrade (for example from A- to Baa+), the cost for new debt would only increase by a few basis points. There is no indication that a Commission decision of 9.50 percent ROE would cause a ratings downgrade, or that the Company would have trouble selling common equity.

Q. WOULD AN ROE DECISION OF 9.5 PERCENT WEAKEN THE COMPANY'S CREDIT PROFILE?

A. No. Dr. Hadaway states that "regardless of the technical merits…the proposed…ROE…would weaken rather than support PacifiCorp's financial condition. (*See* PPL/205 Hadaway/7, 19-20) This statement is misdirected because Dr. Hadaway assumes that the financial metrics used by credit rating agencies were sole determinants of credit ratings. They are not. There is a large subjective component relating to credit ratings. The metrics might, in a theoretical sense, be altered every time the equity rate of return is lowered in a rate case. Conversely, every time the ROE is increased, the "metrics" would be "increased". (*See* "How Returns on Equity Factor into U.S. Utilities' Creditworthiness, Staff/1201 Morgan/1-4)

Clearly, the higher an ROE determination, the better some financial ratios would appear. However, the ROE does not affect the leverage ratio (debt to total capitalization.) Higher ROEs, all else equal, would cause shareholders to "bid-up" share price until the "required return" was equal to the expected return.

I address these dynamics at Staff/202 Morgan/532-533. An indication of this mechanism is related to the market-to-book ratio that I discussed at Staff/200 Morgan/63. Dr. Hadaway's argument is incorrect because it is contrary to the foundation of rate of return determinations, which require allowed returns to be set at a company's cost of capital.

CAPITAL STRUCTURE

Q. WHY DO YOU SUPPORT THE USE OF THE COHORT AVERAGE CAPITAL STRUCTURE?

A. It would be improper to match the cost of equity indications from the sample with a company-specific capital structure without a counterbalancing adjustment to ROE. In this case, staff's estimates would need to be adjusted downward. Even though Mr. Williams refers to my proposed capital structure as "hypothetical", this is not an accurate characterization. (*See* PPL/304 Williams/17) The sample group of companies represents the market prices investors are willing to pay. The current capitalization of the companies represents the current requirements for the cost of equity. Even though there may be an adjustment to the capital structures in the future, it is appropriate to calculate the cost of capital, based on their current conditions. Taken to an extreme, attempting to estimate the "future state" of a company, with regard to any factor, introduces bias. In a future rate case, PacifiCorp could argue for adjustments to the capital structure to be decided. However, any adjustments should be reasonably known and measurable.

CHECK OF REASONABLENESS

Q. HOW DID YOU DETERMINE THE REASONABLENESS OF YOUR CONCLUSION?

A. Dr. Hadaway argues that I did not use any other models as checks of "reasonableness". While I did not, for example, develop the Capital Asset Pricing Model (CAPM), one of the most important factors of the underlying framework includes the ex ante, or expected returns for the market, I provided various reports indicating what overall market returns are expected to be over the foreseeable future. These figures range as low as about eight percent and as high as 11 percent. The overall market expectations can be viewed as an upper limit to reasonable required ROEs for the public utility sector.

As I described in my opening testimony, regulated public utilities have lower risk than the overall market and should have returns lower than that required by the market. This notion is well-founded. Because the average Beta[3] is lower than 1.0, equity returns for regulated public utilities would necessarily be lower than that of the market. The CAPM framework requires a "risk-free rate", a market risk premium, and estimates of Beta. (*See* CUB-ICNU/400 Gorman/26, line 12)

Q. DID YOU CONSIDER OTHER EXPECTATIONS FOR ROES?

A. Yes. I have included information that supports the expectation of ROE decisions under 10.0 percent, and potentially as low as 9.0 percent. (*See* Staff/202 Morgan/341)

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[3] *See* Staff/202 Morgan/542 for a discussion of Beta.

Q. WHAT DOES THIS INFER ABOUT THE COST OF EQUITY FOR REGULATED UTILITIES?

A. Although Staff's historic practice uses some adjustments, I will simplify the process for calculating CAPM. Current 10-year Treasuries are about four percent, which will suffice as the "risk-free" rate.

Because the market return is expected to be no greater than 11.0 percent, the market risk premium would be seven percent (11.0% – 4.0% = 7.0%). Using a Beta of 0.75, which is at the high-end of the range from the sample group's Betas, as published by Value Line,4 the sample group's risk premium is 5.25 percent (7.0% x .75 = 5.25%.) (*See* CUB-ICNU/400 Gorman/29, line 4)

Adding this public utility risk premium to the four percent risk-rate indicates an ROE of 9.25 percent (4.0% + 5.25% = 9.25%.) This indication is consistent with my recommended 9.50 percent cost of equity. Some practitioners prefer using a longer-term Treasury as the risk-free rate. If we assume a 4.5 percent rate, which is in-line with the 20-year Treasury,[5] then the indication from this exercise is only about ten basis points lower than my 9.5 percent recommendation.[6] While this analysis is not proffered as a rigorous CAPM analysis, it does provide a check of reasonableness.[7]

Q. ARE VALUE LINE'S FORWARD-LOOKING ROES USEFUL FOR THE COMMISSION TO MAKE A JUDGMENT?

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[4] Whether Value Line's Beta is the most reflective for use in the CAPM has been debated. It likely provides an upper bound of reasonable Betas, depending on the measurement process. Because Value Line's Beta calculations are available and are independent, they are reasonable for this discussion.

[5] http://www.federalreserve.gov/releases/h15/update/ 20-year: 4.49%, as of June 15th, 2005.

[6] 11.0% - 4.5% = 6.5% (risk premium). Multiplied by 0.75 (Beta) = 4.875%. Summing this with the 4.5% risk-free rate rounds to 9.4%.

[7] Mr. Gorman discusses the CAPM in more detail at CUB-ICNE/400 Gorman/26-30.

A. Value Line's short-term, forward looking ROEs, in aggregate, are anticipated to be in the 11.0 – 11.5 range. However, Dr. Hadaway's selected sample of Companies is more appropriate to develop ROE estimates. This is because the filtering process is designed to remove the bias of unregulated operations.

Dr. Hadaway's argument is erroneous because the Value Line figure of 11.50 percent includes a much larger sample. (*See* PPL/205 Hadaway/10)

The ROE determined by the Commission should not be limited to the forecasts provided in Value Line. Value Line is estimating "earned" ROEs, which may not be consistent with the investment returns actually achieved by investors, includes the impact on current pricing. (*See* discussion on market-to-book factors, at Staff/200 Morgan/63) The earned ROEs are useful for calculating "b x r" growth rates, but DR. Hadaway's sample companies have as much as 30 percent of their revenues generated from unregulated operations. (*See* PPL/200 Hadaway/21)

Q. ARE THERE INDEPENDENT REPORTS PERTAINING TO THE COST OF EQUITY FOR REGULATED UTILITIES?

A. Yes. I have included information that supports the expectation of ROE decisions under 10.0 percent, and potentially as low as 9.0 percent. (*See* Staff/202 Morgan/341)

Q. ARE DR. HADAWAY'S RISK PREMIUM MODELS USEFUL?

A. No. For the reasons identified in my opening testimony, Dr. Hadaway's risk premium models should not be considered.

Q. DO CREDIT RATINGS DEPEND ONLY ON ALLOWED ROES?

A. No. A recent commentary by Standard & Poor's indicates that, even though ROEs directly impact cash flow metrics, there are other regulatory mechanisms that impact the creditworthiness of companies. (*See* Staff/1201 Morgan/1) Other factors, such as Resource Valuation Mechanisms (RVMs) and Power Cost Adjustment Mechanisms (PCA) are designed to help stabilize rates to make minor adjustments to the base rates to reflect actual cost of fuel used in electrical generation. Treatment of pension costs and other considerations are important when considering the creditworthiness of a company.

RELIANCE ON OTHER COMMISSION ROE DECISIONS

Q. SHOULD THE COMMISSION DETERMINE ROES BASED ON THE DECISIONS OF OTHER REGULATORY COMMISSIONS?

A. No. As I indicated in my opening testimony, if the findings in ROE decisions were predicated on past results in other commissions, then the end result would be static ROE decisions. Dr. Hadaway did not address the specific weaknesses with his "risk premium" model. Without a better model specification, the best result from Dr. Hadaway's model would be to derive a 95 percent confidence interval. Outside that range, the Commission could consider whether any decisions would be too extreme.

The highly-contentious issue of ROEs cannot be boiled down to simply taking the average of other Commission's decisions.

Q. ARE THERE OTHER FACTORS THAT IMPACT THE COST OF CAPITAL?

A. Yes. Treatment of pension costs and other considerations are important when considering the creditworthiness of a company, and the decisions of each regulatory agency likely consider such factors, along with capital structure and the pass-through of operating expenses and the cost of debt. Further, S&P notes this is more important than the ROE decision itself. (*See* Staff/1201 Morgan/1)

Q. SHOULD THE ROE YOU RECOMMEND BE SIMILAR TO THOSE ORDERED BY OTHER COMMISSIONS?

A. Not necessarily. Dr. Hadaway asserts that “Mr. Morgan’s ROE recommendation is simply out of step with other state utility regulators’ ROE findings and with ROEs expected by investors.” (*See* PPL/205 Hadaway/11) Dr. Hadaway fails to analyze the underlying factors of each decision. In addition, he did not create a “confidence interval” and he neither considered what rates of return were requested by companies nor what staff and intervenors recommended.

The second argument made by Dr. Hadaway is that the Commission should set ROEs in-line with those “expected by investors”. The cost of equity, as I discussed at length, is based on the required returns of investors. (*See* Staff/202 Morgan/532)

Dr. Hadaway’s argument in favor of averaging other ROE decisions is circular and cedes the important authority for ROE decisions in Oregon to the ROE decisions in other states. The prices that investors are willing to pay for shares, in conjunction with the earnings of a company combine to provide important road signs towards the investors' required returns. If a company's ROE is set too high, that is higher than demanded by investors, the share price will increase until the required return is at equilibrium.[8]

Dr. Hadaway also mentioned the stipulated ROE in PacifiCorp's prior rate case as somehow being relevant to the current case.

PacifiCorp's last rate case was agreed to by all parties and it is not reasonable to consider a single element in a rate case, especially one as important as the cost of equity. Dr. Hadaway did not mention the very recent cost of equity stipulated to by Idaho Power Company, of 9.9 percent (excluding flotation costs.) Idaho Power's capital structure also included only about 46 percent total equity. In either event, staff does not recommend using stipulated ROEs as justification for ROEs in current cases.

OTHER RESPONSIVE ISSUES

Q. TO WHAT OTHER ARGUMENTS WILL YOU RESPOND?

A. There are only a couple additional issues that require a response. These issues will be addressed below in a narrative format.

SPOT PRICES VERSUS AVERAGE PRICES

Dr. Hadaway argues that stock price fluctuations can skew the results of the DCF. While a single company's share price may suffer from a lot of volatility,

[8] Any shifts in allowed ROEs, either higher or lower, can be expected to affect share prices. This is the foundation of the DCF model.

the larger sample of companies used by Dr. Hadaway and myself should reduce the impact on the results of the DCF models.

Dr. Hadaway indicates, "Although in theory either average or "spot" stock prices can be used in the DCF analysis, a reasonably current price consistent with present market conditions and with the other data employed in the analysis is most appropriate. Since the cost of equity is a forward-looking concept, the important issue is that the price should be representative of current market conditions and not unduly influenced by unusual or special circumstances." (*See* PPL/200 Hadaway/22)

The use of spot prices is based on historic Commission practice, and is theoretically appropriate, because all known events are contained in current prices. Using monthly average prices may cause incorrect information to persist in the DCF models.

Dr. Hadaway has not shown if or how this issue affects the final conclusion that I recommend in this case. The end results of the DCF models are much more sensitive to the issue of growth, than to changes in price assumptions. The current prices of the sample of companies I included in my analysis is actually lower than Dr. Hadaway's time-average pricing. All else being equal, this would tend to increase the ROE calculation.

CONVERGENCE

It appears I may have confused Dr. Hadaway by discussing convergence. This may be because he did not consider it in his analysis. (PPL/205 Hadaway/12, 19-20) However, convergence is important.

I described convergence at Staff/200 Morgan/20-22)

ANALYSTS' LONG-TERM GROWTH RATES

Dr. Hadaway discussed an article included in my opening testimony that relates to long-term growth rate consensus of analysts (*See* PPL/205 Hadaway/13)

The articles identified by Dr. Hadaway address do indicate that analyst forecasts go through periods where they are somewhat excessive. He also is correct in that real GDP growth was reported as being about 3.5 percent over the past 70 years. However, it is important to note that these articles do not support the use of GDP growth for regulated utilities.

DR. HADAWAY'S HISTORIC TESTIMONY

Q. PLEASE DESCRIBE DR. HADAWAY'S HISTORIC TESTIMONY.

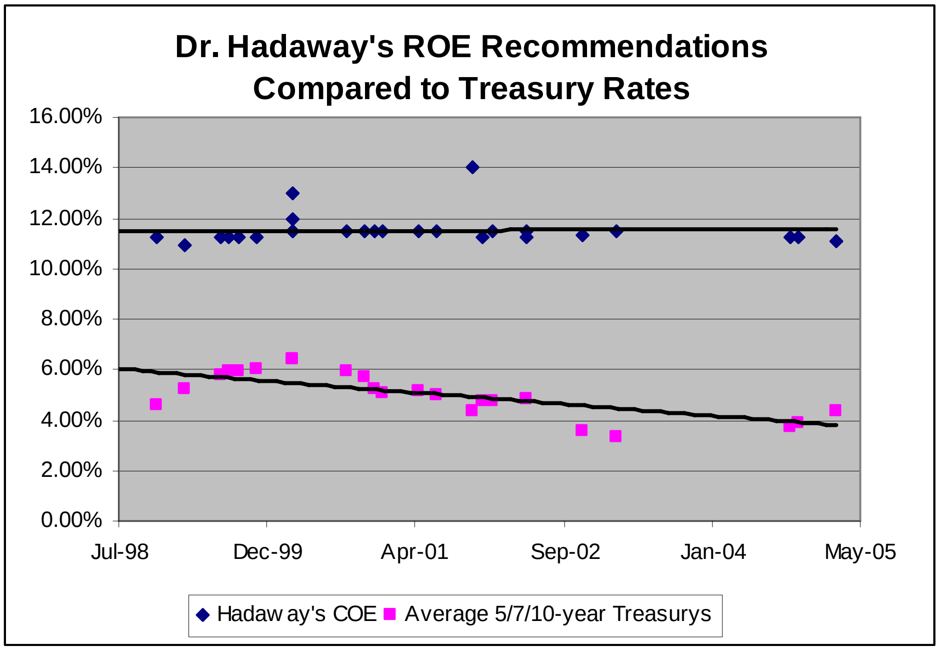
A. The following table (Table 1) represents a summary of the results of his testimony over the past seven-year period. The testimony spans the period from February 1998 through March 2005. He provided 29 ROE recommendations in 13 jurisdictions.

TABLE 1

Date	ROE	Company	Jurisdiction	Dividend Yield	Dividend Growth
Mar-05	11.13%	PacifiCorp	Oregon	4.58%	6.60%
Nov-04	11.25%	CenterPoint Energy	Oklahoma	4.42%	6.77%
Oct-04	11.25%	CenterPoint Energy	Minnesota	4.42%	6.77%
Mar-03	11.50%	PacifiCorp	Oregon	5.66%	5.86%
Nov-02	11.30%	NW Natural Gas	Oregon	5.14%	5.60%
May-02	11.25%	PacifiCorp	Wyoming	5.24%	5.86%
May-02	11.50%	Fitchburg (an LDC)	Mass.	4.78%	7.17%
Jan-02	11.50%	Concord Electric (Unitil)	New Hamp.	5.29%	6.13%
Dec-01	11.25%	PacifiCorp	California	5.21%	6.24%
Nov-01	14.00%	Puget Sound Energy	Washington	5.07%	6.22%
Jul-01	11.50%	Texas-New Mexico Power Company	New Mexico	5.27%	6.27%
May-01	11.50%	Fitchburg (an LDC)	Mass	5.12%	6.36%
Jan-01	11.50%	Southwestern Electric Power Company	FERC	4.98%	6.17%
Nov-00	11.50%	PacifiCorp	Oregon	n/a	n/a
Sep-00	11.50%	American Electric Power	unknown	5.94%	5.25%
Mar-00	11.50%	TXU Electric Company	unknown	5.94%	5.25%
Mar-00	12.00%	Reliant Energy	FERC	5.95%	5.80%
Mar-00	13.00%	Reliant Energy HLP	unknown	n/a	n/a
Mar-00	11.50%	Central Power/Light	Texas	5.94%	5.25%
Dec-00	11.50%	PacifiCorp	Wyoming	4.98%	6.17%
Sep-99	11.25%	PacifiCorp	Utah	5.31%	4.90%
Nov-99	11.25%	PacifiCorp	WUTC	5.63%	5.01%
Jul-99	11.25%	PacifiCorp	Wyoming	5.36%	4.52%
Aug-99	11.25%	Southwestern Electric Power Company	Louisiana	5.25%	4.65%
Mar-99	10.95%	Entergy Gulf States	Texas	n/a	n/a
Dec-98	11.25%	Southwestern Electric Power Company (SWEPCO)	FERC	n/a	n/a
Jun-98	11.25%	Utah Power & light Co.	Utah	n/a	n/a
May-98	11.25%	Fitchburg	Massachusetts	n/a	n/a
Feb-98	11.35%	Texas Utilities Electric (settlement)	Texas	n/a	n/a

The following chart (Chart 1) provides a graphic representation of the same data and is plotted against the contemporary Treasury interest rate data for the period in which his testimony was proffered. Even though Dr. Hadaway's risk-premium model indicates that there is an inverse relationship between interest rates and required equity returns, it appears as if interest rates and the results of his analysis actually bear no relationship to each other.

CHART 1



Q. CAN YOU INTERPRET THESE DATA IN THE CONTEXT OF DR. HADAWAY'S CONCLUSION IN THIS CASE?

A. Yes. If the past seven years is a representative sample, and I believe it is, the current results indicate that the expected ROEs produced by Dr. Hadaway's informed judgment are within the range from 11.25 percent 11.60 which is an extremely narrow distribution, given that each analysis contained differing capital structures, geographic locations, interest rates and other factors that would be expected to affect the cost of equity.

Additionally as interest rates have trended downward significantly, the risk-premium implied by Dr. Hadaway has increased considerably in order to maintain the same final conclusion. The following table represents the summary annual statistics for each of Dr. Hadaway's cost of equity proposals and includes the risk premium that is implied by each:

Year	Hadaway's ROE	Average Treasurys	Difference
2005	11.13%	4.33%	6.79%
2004	11.25%	3.80%	7.45%
2003	11.50%	3.31%	8.19%
2002	11.39%	4.50%	6.89%
2001	11.95%	4.88%	7.07%
2000	11.79%	6.08%	5.71%
1999	11.19%	5.81%	5.38%
1998	11.28%	5.33%	5.94%

MR. GORMAN'S SAMPLE SELECTION

One would expect too broad of a sample to actually indicate ROEs that are above what would be required for rate-regulated assets. Not knowing the reconciliation process used by Mr. Gorman, it is possible that he tempered his results to reflect the returns for PacifiCorp's regulated assets.

Rather than use "commission-authorized returns" and Moody's bond yields in his risk-premium model, Mr. Gorman's model uses the risk-free rate (Treasury). However, the model suffers from the same weaknesses, including the potential for having left important explanatory variables out of the model.

CONCLUSION

The Commission should adopt staff's recommendation of 9.5 percent for the cost of equity. It should also adopt staff's recommendation regarding the capital structure.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CASE: UE 170
WITNESS: Ming Peng

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Surrebuttal Testimony

June 27, 2005

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Ming Peng (Staff). My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2148. My telephone number is (503) 373-1123. I am employed by the Public Utility Commission of Oregon (OPUC) as a Utility Analyst of the Economic and Policy Analysis Section in the Economic Research and Financial Analysis Division.

Q. ARE YOU THE SAME MING PENG WHO PREVIOUSLY TESTIFIED ON BEHALF OF STAFF?

A. Yes.

Q. HAVE YOU PREPARED ANY EXHIBITS?

A. Yes, I have prepared Staff Exhibit 1300 consisting of 6 pages.

Purpose of Testimony

Q. WHAT IS THE PURPOSE OF THIS SURREBUTTAL TESTIMONY?

A. I respond to the Company's rebuttal testimony on the following issues:

1. Embedded Cost of Preferred Stock
2. Embedded Cost of Long-Term Debt

Summary Recommendation

Q. WHAT ARE YOUR SUMMARY RECOMMENDATIONS?

A. I recommend the Commission:

(1) reject the Company's proposed cost of long-term debt and cost of preferred stock;

(2) adopt Staff's revised estimate of 6.14% for the embedded cost of long-term debt;

(3) adopt Staff's estimate of 6.44% for the cost of preferred stock;

STAFF-PROPOSED COST OF CAPITAL - Surrebuttal

Capital Component	Cost	Ratio	Weighted Cost
Long-Term Debt	6.14%	49.40%	3.03%
Preferred Stock	6.44%	1.09%	0.07%

COMPANY-REQUEST COST OF CAPITAL - Rebuttal

Capital Component	Cost	Ratio	Weighted Cost
Long-Term Debt	6.35%	49.44%	3.14%
Preferred Stock	6.59%	1.06%	0.07%

Embedded Cost of Preferred Stock

Q. WHAT ADJUSTMENTS DID YOU MAKE TO PACIFICORP'S EMBEDDED COST OF PREFERRED STOCK?

A. In my direct testimony, I removed $152,115 of unamortized expense from an early retirement of the QUIDS (Quarterly Income Debt Securities). Additionally, I made an adjustment to the issuance costs related to the shares outstanding associated with the $7.48 No Par Serial Preferred Stock series.

Q. WHY DID YOU REMOVE QUIDS' UNAMORTIZED EXPENSE FROM YOUR CALCULATION OF THE EMBEDDED COST OF PREFERRED STOCK?

A. Consistent with my direct testimony, there are several reasons for excluding the cost of the QUIDS. First, the unamortized expense associated with the QUIDS should not be reflected in rates because the QUIDS are no longer outstanding and no replacement debt has been identified. Second, the expenses are non-recurring in nature, and as such should not be included in rates. Third, there is no evidence that customers benefited from the early redemption of the QUIDS. Fourth, the Commission excluded the unamortized expense associated with the QUIDS in Order 01-787, UE 116, in 2001. The Commission decision in that case remains sound and should not be reversed.

Q. PLEASE DISCUSS YOUR ADJUSTMENT ON THE ISSUANCE COSTS RELATED TO THE SHARES OUTSTANDING ASSOCIATED WITH THE $7.48 NO PAR SERIAL PREFERRED STOCK SERIES.

A. PacifiCorp believes that "the projected preferred stock balance on the Staff witness's chosen year-end 2006 date appears to remove approximately one and one-half year's mandatory redemption" (PPL/304, Williams/2). The rationale for selecting the Dec. 2006's principal balance for purposes of setting a sinking fund schedule is that this date is a midpoint-balance of the interval between the current rate case and another possible rate case. The midpoint of the outstanding balance will better represent a reasonable periodic payment rate. Choosing an earlier date could result in over-collection. Choosing a later date, than the midpoint, could result in under-collection, since the outstanding balance of these preferred shares will have decreased over the time that rates are in effect.

The midpoint (Dec. 2006) approach does not remove any periodic payment, neither does it change the payment schedule. What it does is to select the initial outstanding balance to calculate the payment being made into the sinking fund, with the objective of avoiding over- or-under payments.

Q. DID YOU ACCEPT THE COMPANY'S ADJUSTMENT TO REMOVE AN ADDITIONAL $3.75 MILLION FROM THE COMPANY'S PREFERRED STOCK BALANCE AS OF MARCH 31, 2006 DUE TO THE ERROR IN THE COMPANY'S DIRECT TESTIMONY?

A. Yes.

Q. DID YOU THEREFORE MODIFY YOUR ADJUSTMENT ON THE COMPANY'S PREFERRED STOCK AFTER THE COMPANY AMENDED ITS PREFERRED BALANCE?

A. Yes. I revised the midpoint of the outstanding shares from 430,000 to 468,750 based on PacifiCorp's clarification that "Both the outstanding shares and issuance costs are now 60 percent of the amounts at the time of original issuance." (Rebuttal testimony: PPL/304, Williams/4) PacifiCorp's "the original issuance cost will be further reduced to $504,260 on June 15, 2005." The cost of preferred stock is therefore calculated as 6.44%.

Embedded Cost of Long-Term Debt

Q. WHAT ADJUSTMENTS DID YOU MAKE ON COST OF DEBT?

A. In my direct testimony, I adjusted the interest rate on the "Pro-forma Debt" to reflect an average of interest rate of five percent (5%). This value also reflects a 10-year maturity term. However, upon further reflection and review of prior commission cases, using a 10-year maturity is inconsistent with past Commission policy. The historical practice by Commission staff, and adopted by the Commission is to use the average of 5-, 7- and 10-year terms.

Therefore, for this testimony, I have used the current returns of 5, 7 and ten-year term treasuries. The average of the 5-, 7-, 10-years' Treasury rate is 3.94%. The average 5-, 7-, 10-years' PacifiCorp's A-rated spreads is 78 basis points. The sum of the average Treasury rate and the average spread is a cost, or rate, of 4.72% for PacifiCorp's incremental cost of debt.

Q: DID YOU ACCEPT THE COMPANY'S ADJUSTMENT REGARDING TO THE REMAINING BALANCE OF UNAMORTIZED REDEMPTION EXPENSE ON LONG TERM DEBT?

A: Yes, I accepted the Companies argument and removed Staff's adjustment to redemption expenses discussed in Staff/300, Peng/11.

Q. WHAT IS STAFF'S REVISED ESTIMATE OF PACIFICORP'S EMBEDDED COST OF LONG-TERM DEBT?

A. Using the above method for replacing retiring debt, and taking a weighted average of that debt with PacifiCorp's long-term debt (for which the terms do not end within the test year). Staff recommends the Commission adopt a long-term cost of debt for PacifiCorp of 6.14%.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

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I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to all parties or attorneys of parties.

Dated at Salem, Oregon, this 27th day of June, 2005.

David B. Hatton

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