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July 24, 2009

Via Electronic and US Mail

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

Re: In the Matter of PACIFICORP Request for a General Rate Revision
Docket No. UE 210

Dear Filing Center:

Enclosed please find the original and five (5) copies of the following testimony on behalf of the Industrial Customers of Northwest Utilities in the above-referenced docket:

Reply Testimony of Randall Falkenberg (ICNU/100) with Exhibits (ICNU 101 – ICNU/104); and

Reply Testimony of Donald Schoenbeck (ICNU/200) with Exhibits (ICNU 201 – ICNU/208).

Also enclosed please find the original and five (5) copies of the following testimony on behalf of the Industrial Customers of Northwest Utilities and the Citizens' Utility Board of Oregon in the above-referenced docket:

Reply Testimony of Michael Gorman (ICNU-CUB/300) with Exhibits (ICNU-CUB 301 – ICNU-CUB/323); and

Reply Testimony of Ellen Blumenthal (ICNU-CUB/400) with Exhibits (ICNU-CUB 401 – ICNU-CUB/403).

Thank you for your assistance.

Sincerely,

/s/ Brendan E. Levenick
Brendan E. Levenick

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Reply Testimony on behalf of the of the Industrial Customers of Northwest Utilities and the Citizens' Utility Board of Oregon upon the parties, on the service list, by causing the same to be deposited in the U.S. Mail, postage-prepaid, and via electronic mail where paper service has been waived.

Dated at Portland, Oregon, this 24th day of July, 2009.

Sincerely,

/s/ Brendan E. Levenick
Brendan E. Levenick

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
Request for a General Rate Revision.	)

REPLY TESTIMONY OF MICHAEL P. GORMAN

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

AND

THE CITIZENS' UTILITY BOARD OF OREGON

July 24, 2009

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017. I am employed by the firm of Brubaker & Associates, Inc. ("BAI"), regulatory and economic consultants with corporate headquarters in Chesterfield, Missouri. My qualifications are described in ICNU-CUB/301.

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

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU") and the Citizens' Utility Board of Oregon ("CUB"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including PacifiCorp dba Pacific Power ("PacifiCorp" or the "Company"). CUB is a non-profit created by legislation in 1985 to ensure that residential utility consumers have an effective advocate to reflect their needs and interests when it comes to public policies affecting the quality and price of utility services. ORS 774.020 and 774.030. CUB's membership averages 4,500 persons per year.

Q. WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A. I will recommend a fair return on common equity and overall rate of return for PacifiCorp. I will also respond to PacifiCorp's rate of return witness Dr. Samuel C. Hadaway and his proposed return on common equity of 11.0%.

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

A. Yes. I am sponsoring Exhibits ICNU-CUB/301 through ICNU-CUB/323.

I. SUMMARY

Q. PLEASE SUMMARIZE YOUR RETURN ON EQUITY RECOMMENDATIONS.

A. Based on my proposed capital structure, I recommend the Oregon Public Utility

Commission ("OPUC" or the "Commission") award PacifiCorp a return on common equity of 10.0%, which is the midpoint of my estimated range of 9.60% to 10.40%. I recommend an overall rate of return of 8.01% for PacifiCorp, as shown on ICNU-CUB/302.

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

I will also respond to PacifiCorp witness Dr. Samuel Hadaway's proposed return on equity of 11.00%. For the reasons discussed below, Dr. Hadaway's recommended return on equity for PacifiCorp is excessive and should be rejected.

Q. HOW DID YOU ESTIMATE PACIFICORP'S CURRENT MARKET COST OF EQUITY?

A. I did this by development of a comparable proxy investment group of publicly traded utility companies that have investment risk similar to PacifiCorp. I then performed three versions of the Discounted Cash Flow ("DCF") model, Risk Premium ("RP") study, and Capital Asset Pricing Model ("CAPM") analysis. Based on these assessments, and as discussed in more detail below, I estimate PacifiCorp's current market cost of equity to be 10.0%.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR RETURN ON EQUITY AND CAPITAL STRUCTURE ADJUSTMENTS?

A. The revenue impact from reducing PacifiCorp's return on equity from 11% down to 10% and reducing its common equity ratio from 51.2% to 50.5% lowers its claimed Oregon jurisdictional revenue deficiency by $26.7 million.

Q. HOW DOES YOUR RECOMMENDED RETURN ON EQUITY COMPARE TO PACIFICORP'S CURRENT AUTHORIZED RETURN ON EQUITY IN OREGON?

A. My recommended return on equity for PacifiCorp is the same return on equity previously authorized to PacifiCorp in its most recent general rate case. Re PacifiCorp, Docket No. UE 179, Order No. 06-530 at 4 (Sept. 14, 2006). My estimate of PacifiCorp's current authorized return on equity of 10% is still reasonable given the circumstances and market changes that have occurred since PacifiCorp's last rate case.

Specifically, while capital markets and economy have gone through significant distress since PacifiCorp's last rate filing, capital markets have improved since the end of 2008/beginning of 2009, and continue to strengthen and are returning to more normal capital market conditions. Further, the economy has dipped into a recession, but now appears to be picking up strength, and a full economic recovery is projected to start to take effect at the end of this year, and in through 2010. Hence, the rates determined in this proceeding will be in effect during a period which will reflect a recovery of the capital market and the local economy.

It would be prudent and reasonable for the Commission to award PacifiCorp a return on equity of 10.0%, which reflects no increase to its last return on equity, because that return level is appropriate and reasonable, and will not create unnecessary price pressure on PacifiCorp's retail customers. Mitigating any increases in prices is critical in supporting PacifiCorp's service territory's recovery through this economic downturn, and also this fair compensation that will preserve PacifiCorp's financial integrity during this downturn and up through an improvement in capital markets and service area economy. For all these reasons, PacifiCorp's authorized return on equity should continue to be set at 10.0%.

II. RATE OF RETURN

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony:

1. I will review the current electric utility industry market outlook.
2. I will review the investment risk of PacifiCorp.
3. I will propose a capital structure that will maintain PacifiCorp's financial integrity.
4. I will estimate a fair return on equity for PacifiCorp.
5. I will show that my recommended rate of return will support PacifiCorp's financial integrity and investment grade bond rating.
6. Finally, I will respond to PacifiCorp witness Dr. Samuel C. Hadaway's recommended return on equity of 11.0% and explain why it is excessive and unreasonable.

II.1. Electric Utility Industry Market Outlook

Q. PLEASE DESCRIBE THIS SECTION OF YOUR TESTIMONY.

A. I will review the credit rating and investment return performance of the electric utility industry. Based on the assessments below, I find the credit rating outlook of the industry to be strong and supportive of the industry's financial integrity. Further, electric utilities' stocks have exhibited strong return performance and are again characterized as a safe investment.

Q. PLEASE DESCRIBE THE ELECTRIC UTILITIES' CREDIT RATING OUTLOOK.

A. Standard & Poor's ("S&P") provided an assessment of the credit rating of U.S. electric utilities for the first quarter 2009. S&P's commentary included the following:

> Against a strong headwind in the credit markets, the regulated U.S. electric utility sector performed well during the first quarter of 2009. Highlights include continued capital market access with robust debt issuance by operating companies in this quarter. March 2009 issuance volume exceeded the combined first two months of 2009; through the first quarter of 2009 issuance exceeded $16 billion, about 25% more than the same 2008 period. Several companies have proactively prefunded issuance in advance of maturities, taking advantage of investor appetite and favorable spreads as compared to investment-grade issuers in other sectors.
>
> * * *
>
> Our forecast for the electric sector is for a stable ratings trend for the balance of 2009. Currently, more than three-quarters of rated entities have stable outlooks with the average rating at 'BBB'. The depth of the recession in certain pockets of the U.S. economy, combined with weaker cash flow measures and ballooning debt balances, may cause credit deterioration on the margin for some, but we expect the majority of electric companies to maintain current ratings in 2009. Our forecast incorporates expectations of responsive regulatory decision making, continued demand by investors for utility operating company debt, ample liquidity access provided by bank lines, and moderate capital expenditures. On the horizon, future capital needs to improve reliability, integrated renewable resources, and potentially address carbon emissions limit upward rating momentum for the near term.[1/]

Further, Moody's also acknowledges the following for the electric utility industry in its report. Moody's states:

> **Overview**
> The U.S. investor-owned electric utility sector enjoys solid credit metrics and the fundamental credit outlook remains stable. In general, state regulators continue to let the utilities recover prudently incurred operating costs and capital expenditures relatively quickly, and with reasonable rates

[1/] Standard & Poor's RatingsDirect: "Industry Report Card: U.S. Electric Utility Sector Performed Well In First Quarter Of 2009," March 30, 2009 (emphasis added).

> of return. Moreover, we believe state regulators would otherwise prefer to regulate financially healthy companies.
>
> The sector is also well positioned relative to many other corporate/industrial sectors, primarily due to the fundamental business plan: providing monopolistic electric service within a designated service territory in exchange for oversight and limitations on profitability. However, we are increasingly concerned with business and operating risks, which are not new but appear to be accelerating faster than previously understood. These business and operating risks include potential environmental legislation from the Obama Administration; the continued capital investment needs for refurbishing aging infrastructure; and a potentially more contentious regulatory relationship amid a protracted or severe recession.[2/]

Similarly, Fitch states:

> The utilities segment is not immune to the economic challenges facing corporate America, but is relatively well positioned. Providing essential services and largely regulated, utilities benefit from investor perceptions as a defensive group. For the most part, electric utilities reduced debt and focused on improving their core business over the past four years. Consequently, while many industries and companies have recently been shut out of the capital markets, stronger utilities have accessed both secured and unsecured markets. However, investor "flight to quality" is selective within the sector, favoring companies at higher rating levels, with a marked preference for secured debt and lending at the operating, rather than parent, company.[3/]

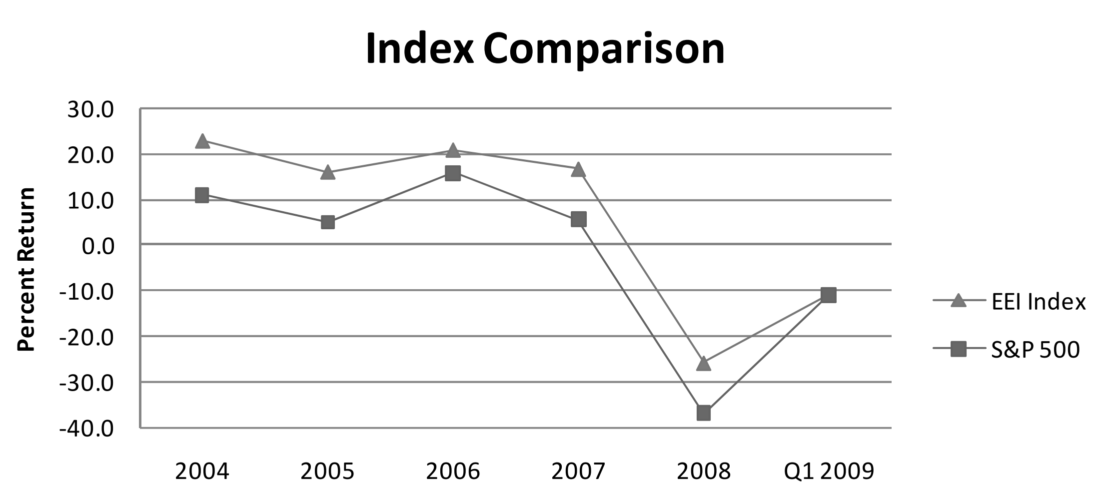
As noted by S&P, Moody's and Fitch above, the regulated electric utility industry is maintaining strong investment grade credit and is well positioned to weather the current economic downturn. Therefore, reasoned and rational adjustments to PacifiCorp's rates would be appropriate to provide fair compensation, but not excessive compensation, in an effort to improve PacifiCorp's competitive position and support its credit quality.

2/ Moody's Investors Service Industry Outlook: "U.S. Investor-Owned Electric Utilities," January 2009 (emphasis added).

3/ Fitch Ratings: "U.S. Utilities, Power and Gas 2009 Outlook," December 22, 2008.

Q. PLEASE DESCRIBE THE ELECTRIC UTILITY STOCK PRICE PERFORMANCE OVER THE LAST FIVE YEARS.

A. As shown in the graph below, Edison Electric Institute ("EEI") has recorded electric utility stock price performance compared to the market. The EEI data show that its Electric Utility Index has outperformed the market in every year over the last five years. Again, this strong stock performance indicates commission-authorized returns on equity over the last several years have been positively received by the market.



Source: EEI Q1 2009 Stock Performance Financial Update, at Page 1.

Q. FOR 2008, THE ELECTRIC UTILITY STOCK AND THE OVERALL MARKET PRICE PERFORMANCE HAS BEEN SIGNIFICANTLY NEGATIVE. DOES THIS TIME PERIOD ALSO SUPPORT YOUR POSITION THAT REGULATED ELECTRIC UTILITY STOCK PERFORMANCE HAS BEEN STRONG RELATIVE TO THE MARKET?

A. Yes. While clearly the market performance for all securities was poor throughout 2008, one positive signal from the market performance is the fact that electric utility stocks and bonds have continued to be perceived by the market as "safe" investments. Indeed, during times of market duress, the market generally exhibits a "flight to quality," and lower-risk securities generally perform better than the overall market and higher-risk securities. This has happened throughout the last year. For example, EEI noted the following concerning electric utility stock performance in 2008:

> **Flight to Safety**
> The relatively stronger performance of utility stocks in both the quarter and the year offers a classic illustration of their traditional role as a defensive investment in times of market stress. In a weakening economy, investors are drawn to the relative stability offered by utilities' dividend yields and more predictable earnings (in comparison with other sectors of the economy), made possible by the essential role that electricity plays in the lives of Americans at work and at home compared to other, more optional products and services.
>
> Indeed, the comparative category returns shown in Charts II and VIII highlight the theme that dividend stability and earnings predictability – generally most associated with the regulated utility business model – translated into better stock market performance in 2008. The Regulated group's -5.9% return in the fourth quarter was about 8 percentage points better than the Mostly Regulated group's -14.0% return, which in turn was slightly better than the Diversified group's -17.0% return. The Regulated group, with a -15.6% return for the year as a whole, also outperformed the Mostly Regulated group's -27.0% return and the Diversified group's -33.9% return for the year.[4/]

This stock price performance again supports the notion that regulated electric utilities are perceived by the market as safe haven investments, which will help support their access to capital during difficult financial times. This is clearly evident through a review of their stable credit outlook and stable stock prices, relative to the securities of non-regulated companies.

II.2. PacifiCorp Investment Risk

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF PACIFICORP AND ITS INVESTMENT CHARACTERISTICS.

A. PacifiCorp is owned by MidAmerican Energy Holdings Company ("MEHC"). PacifiCorp's current senior secured bond ratings from S&P and Moody's are "A-" and

[4/] "Stock Performance," EEI *Q4 2008 Financial Update* at 4-5.

"A3," respectively.[5/] PacifiCorp's corporate credit ratings from S&P and Moody's are "A-" and "Baa1," respectively.[6/]

Specifically, S&P states the following:

> **Rationale**
> The 'A-' corporate credit rating (CCR) on PacifiCorp reflects its 'excellent' business profile, evidenced by a diverse and growing service territory, and an 'aggressive' financial profile that reflects a large capital program and the need to shore up its cash flow metrics. While the ring-fenced utility's credit metrics are more consistent on a standalone basis with a 'BBB' category rating, Standard & Poor's Ratings Services expects that management will achieve cash flow metrics more consistent with an 'A' category rating over the next several years. PacifiCorp is owned by parent MidAmerican Energy Holdings Co. (MEHC; BBB+/Stable/--).
>
> * * *
>
> **Outlook**
> The stable outlook for PacifiCorp incorporates our expectation that MEHC will continue to support the utility by contributing equity sufficient to ensure that our fully adjusted debt to total capitalization is managed over the next few years to an adjusted level of closer to 50% and that FFO to total debt and interest coverage will be 20% or better and in the range of 4.0x-4.5x, respectively. Given that PacifiCorp's financial profile is weak for the current ratings, we do not anticipate near-term upward ratings momentum for the utility, which would require the company to sustain metrics above these levels. PacifiCorp's ring-fenced structure insulates it from some MEHC credit deterioration, to an extent. Specifically, our criteria provides that PaciCorp's [sic] CCR can be no more than three notches above the MEHC CCR. The company is currently comfortably within this range, and as a result we do not see significant prospects for the utility's rating to fall as a result of adverse rating changes at MEHC, which also enjoys a stable outlook.[7/]

Similarly, Moody's confirms PacifiCorp's supportive regulatory treatment:

> **Rating Rationale**
>
> PacifiCorp's Baa1 rating for its senior unsecured obligations is driven by the stability of its regulated cash flows, the geographically diverse and relatively constructive regulatory environments in which it operates, the

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5/ PPL/200, Hadaway/3.

6/ PacifiCorp 2008 10-K at 61.

7/ Standard & Poor's RatingsDirect Summary: "PacifiCorp," April 1, 2009 (emphasis added).

diversification of its generation portfolio, financial credit metrics that are within the ranges demonstrated by U.S. integrated electric utilities rated Baa, and its position as the largest subsidiary of MEHC. The rating also considers PacifiCorp's plans for significant capital investment in generation and transmission and for environmental compliance. The stable outlook incorporates Moody's expectation that PacifiCorp will continue to receive generally supportive regulatory treatment to recover its increased costs and that capital expenditures will be financed in a manner that is consistent with its current credit profile.

* * *

Reasonably Supportive Regulatory Environment

PacifiCorp's rating recognizes that the regulated nature of its businesses and acknowledges the relative stability and predictability of cash flows associated with these operations. The rating also considers PacifiCorp's specific regulatory relationships. In 2007, approximately 72% of PacifiCorp's retail revenues were subject to regulatory oversight in Utah and Oregon which Moody's generally ranks as average among U.S. regulatory jurisdictions in terms of framework development, consistency and predictability of decisions, and expectation of timely recovery of costs and investments. In Oregon, California and Wyoming (44% of 2007 revenues) regulators have authorized adjustment mechanisms to recover changes in the costs of fuel and purchased power. Such provisions add adjustment mechanisms to recover changes in the costs of fuel and purchased power. Such provisions add predictability to utility returns and reduce implementation lag. In an attempt to minimize regulatory lag and earn its allowed ROEs, PacifiCorp is filing more frequent rate cases in all its jurisdictions.

* * *

Existence of Ring-Fencing Provisions

PacifiCorp is ring-fenced via a special purpose entity structure, which preserves its credit profile as an independent operating company, separate from its ultimate parent company. The structure includes typical ring-fencing provisions such as an independent director, separate books and records, restrictions on affiliate transactions (arm's length), prohibitions on collateralizing or guaranteeing affiliate debt, and restrictions on dividend distributions. PacifiCorp's dividend distributions are subject to compliance with certain financial tests, including a minimum interest coverage ratio of 2.5 times and minimum equity ratio in the range of 44-48.25%.

> **Financial Metrics**
>
> PacifiCorp's cash flow metrics are expected to remain fairly stable over the near-to-medium term as the company continues with its significant capital expenditure program. Moody's anticipates the company will proactively seek additional rate recovery for increased costs and investments, and that dividend policy will continue to be established in a manner that is supportive of the company's current credit profile. Over the next few years, Moody's anticipates PacifiCorp's ratio of CFO pre-W/C to Debt will remain in the range of 17-19% and that its interest coverage ratio will be in a range of 4.0-5.0 times.[8]

Q. WHAT DO YOU RECOMMEND THE OPUC TAKE FROM THIS CREDIT REPORT REVIEW OF THE REGULATORY TREATMENT PACIFICORP IS RECEIVING?

A. Credit analysts consider the regulatory treatment for PacifiCorp to be constructive and supportive of PacifiCorp's excellent business risk profile and stable investment grade credit standing.

II.3. PacifiCorp's Proposed Capital Structure

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

A. PacifiCorp's proposed capital structure, as supported by PacifiCorp witness Mr. Bruce N. Williams, is shown below in Table 1.

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[8] Moody's Investors Service Credit Opinion: "PacifiCorp," October 17, 2008 (emphasis added).

TABLE 1

PacifiCorp's Proposed Capital Structure
(December 31, 2009)

Description	**Percent of Total Capital**
Long-Term Debt	48.5%
Preferred Stock	0.3%
Common Equity	51.2%
Total Regulatory Capital Structure	100.0%

Source: PPL/300, Williams/3.

Q. DO YOU HAVE ANY ISSUES WITH PACIFICORP'S PROPOSED CAPITAL STRUCTURE?

A. Yes. Mr. Williams' proposed capital structure is unreasonable because he has overstated the amount of common equity in the capital structure. Specifically, in projecting his capital structure for end-of-year 2009, he started with PacifiCorp's end-of-year 2008 capital structure. Mr. Williams adjusted the end-of-year 2008 capital structure to end-of-year 2009 by reflecting an increase in common equity and debt. He increased the common equity capital by reflecting an equity contribution of $200 million planned to be made in December 2009 (Response to ICNU Data Request ("DR") 2.11), and he added retained earnings based on the retention of all projected 2009 net income.

Q. PLEASE DESCRIBE WHY YOU BELIEVE MR. WILLIAMS HAS OVERSTATED THE AMOUNT OF COMMON EQUITY AT DECEMBER 31, 2009.

A. Mr. Williams' increased the retained earnings for projected 2009 net income. The 2009 net income projection reflects a return on year-end 2008 common equity of approximately 10.0%. However, the Company's filing indicates that without a rate increase, it will earn a 6.517% return on equity, well beneath Mr. Williams' assumption.

Reflecting a return on equity of 6.517% in 2009, PacifiCorp would have $387 million of net income to retain as developed on my ICNU-CUB/302. Including the planned December 2009 equity contribution of $200 million, produces a projected end-of-year 2009 equity balance of $6.53 billion.

I propose an adjusted capital structure based on a common equity ratio of 50.5% be used to set rates. ICNU-CUB/302, Gorman/1.

Q. WHAT IS YOUR PROPOSED CAPITAL STRUCTURE IN THIS PROCEEDING?

A. My proposed capital structure is shown below in Table 2.

TABLE 2

ICNU-CUB Proposed Capital Structure
(December 31, 2009)

Description	Percent of Total Capital
Long-Term Debt	49.2%
Preferred Stock	0.3%
Common Equity	50.5%
Total Regulatory Capital Structure	100.0%

Source: ICNU-CUB/302.

Q. IS YOUR PROPOSED ADJUSTED CAPITAL STRUCTURE REASONABLE?

A. Yes. The capital structure is reasonable for at least three reasons. First, it reflects an estimated increase in retained earnings that is consistent with the Company's representation of the earnings level that will be produced at current rates. If the Company would earn the 10% return on equity at current rates as Mr. Williams' capital structure projections imply, then there may be no need for a rate increase in this proceeding.

Second, my adjusted capital structure is comparable to the capital structure PacifiCorp witness Mr. Bruce Williams proposed in PacifiCorp's current Washington rate case (Washington Utilities and Transportation Commission Docket No. UE-090205). In Washington, Mr. Williams relied on a five-quarter average PacifiCorp capital structure ending June 30, 2009. Excluding short-term debt, Mr. Williams proposed a capital structure composed of a common equity ratio of 50.3%, excluding short-term debt. Re PacifiCorp, WUTC Docket No. UE-090205, Direct Testimony of Bruce Williams, Exhibit No. ___(BNW-1T) at 3.

Third, a common equity ratio of 50.5% is comparable to Dr. Hadaway's proxy group projected three- to five-year average common equity ratio of 50.3%, that was used to estimate PacifiCorp's return on equity. PPL/300, Williams/6.

Q. IS THERE EVIDENCE IN THE RECORD THAT WOULD SUGGEST THAT A LOWER COMMON EQUITY MIGHT BE APPROPRIATE FOR PACIFICORP?

A. Yes. PacifiCorp witnesses have described proposals to acquire generating stations that can replace existing power purchase agreements ("PPA"). By replacing PPAs by Company-owned generating stations, it can reduce the amount of purchased power off-balance sheet debt equivalents. This would have the effect of reducing the adjusted common equity ratio and adjusted debt ratio considered by credit rating analysts in assigning PacifiCorp's bond rating.

PacifiCorp witness Gregory N. Duvall states that the Company has acquired the Chehalis Power Generating Station, a 511 MW cogeneration natural gas-fired plant. Mr. Duvall states at page 6 of his testimony, that the acquisition of this plant will replace four long-term PPAs. PPL/600, Duvall/6. By acquiring the plant, and reducing the PPA debt equivalent, PacifiCorp's off-balance sheet PPA equivalent will be reduced. As such, its on-balance sheet common equity ratio can be reduced without increasing its debt ratio adjusted for PPA debt equivalent.

Q. WILL YOUR PROPOSED CAPITAL STRUCTURE SUPPORT PACIFICORP'S FINANCIAL INTEGRITY AND CREDIT RATING?

A. Yes. As I will discuss later in my testimony my proposed capital structure is consistent with PacifiCorp's current credit rating and will support PacifiCorp's financial integrity.

II.4. Return on Common Equity

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

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

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

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

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

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

A. I have used several models based on financial theory to estimate PacifiCorp's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model; (2) a sustainable growth DCF model; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a Capital Asset Pricing Model ("CAPM"). I have applied these models to a group of publicly traded utilities that I have determined reflect investment risk similar to PacifiCorp.

Q. HOW DID YOU SELECT A PROXY GROUP OF UTILITIES SIMILAR IN INVESTMENT RISK TO PACIFICORP TO ESTIMATE ITS CURRENT MARKET COST OF EQUITY?

A. I relied on the same proxy group used by PacifiCorp witness Dr. Hadaway to estimate PacifiCorp's return on equity.

Q. HOW DOES THIS PROXY GROUP'S INVESTMENT RISK COMPARE TO THE INVESTMENT RISK OF PACIFICORP?

A. The proxy group is shown on ICNU-CUB/303. This proxy group has an average senior secured credit rating from S&P of "A," which is reasonably comparable to PacifiCorp's senior secured credit rating from S&P of "A-". The proxy group's senior secured credit rating from Moody's is "A2," which is also reasonably comparable to PacifiCorp's senior secured credit rating from Moody's of "A3". Therefore, my proxy group has comparable total investment risk to PacifiCorp.

The proxy group has an average common equity ratio of 47.9% (including short-term debt) from AUS and 48.8% (excluding short-term debt) from *Value Line* in 2008. This proxy group's common equity ratio is lower than my proposed common equity ratio for PacifiCorp of 50.5%. However, the proxy group's *Value Line* equity ratio is projected to increase to 50.3% in three to five years, as noted by Mr. Williams. PPL/300, Williams/6. A comparable common equity ratio demonstrates that PacifiCorp's financial risks are comparable or lower than my proxy group.

I also compared PacifiCorp's business risk to the business risk of my proxy group based on S&P's ranking methodology. PacifiCorp has a business risk profile of "Excellent," which is identical to the risk profile of my proxy group. S&P's profile score methodology is discussed later in my testimony.

II.5. Discounted Cash Flow Model

Q. PLEASE DESCRIBE THE DCF MODEL.

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

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \;....\; \frac{D_\infty}{(1+K)^\infty} \text{ where} \qquad \text{(Equation 1)}$$

P_0 = Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

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

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

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

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

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

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

A. I relied on the average of the weekly high and low stock prices over a 13-week period ended June 19, 2009. An average stock price is less susceptible to market price variations than a spot price. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not be reflective of the stock's long-term value.

A 13-week average stock price is still short enough to contain data that reasonably reflect current market expectations, but is not so short a period as to be susceptible to market price variations that may not be reflective of the security's long-term value. In my judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and the need to capture sufficient data to smooth out aberrant market movements.

I used the most recently paid quarterly dividend, as reported in *The Value Line Investment Survey*. This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above.

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

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

Security analysts' growth estimates have been shown to be more accurate predictors of future returns than growth rates derived from historical data because they are more reliable estimates.[9/] Assuming the market generally makes rational investment decisions, analysts' growth projections are more likely the growth estimates considered by the market that influence observable stock prices than are growth rates derived from only historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for the investor consensus dividend growth rate expectations. I used the average of three sources of analysts' growth rate estimates: Zacks, SNL Financial and Thomson Financial (or First Call). All consensus analysts' projections used were available on June 19, 2009, as reported online.

Each consensus growth rate projection is based on a survey of security analysts. The consensus estimate is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. It is problematic as to whether any particular analyst's forecast is more representative of general market expectations. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations.

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

Q. WHAT IS THE GROWTH RATE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A. The growth rates I used in my DCF analysis are shown in Exhibit ICNU-CUB/304. The average growth rate for my proxy group is 6.06%.

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

A. As shown in Exhibit ICNU-CUB/305, the average constant growth DCF return for the proxy group is 11.68%.

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

A. Yes. The constant growth DCF return is not reasonable and represents an inflated return for PacifiCorp at this time. The constant growth DCF result is unreliable and inflated because it is based on an adjusted dividend yield of 5.63%, which has increased significantly due to current constrained market conditions, and a growth rate of 6.06% that reflects abnormally high growth that is not sustainable indefinitely as required by this model. See ICNU-CUB/305.

I believe the dividend and growth components of the constant growth model are producing irrational results because they appear to reflect completely contradictory outlooks for the utility industry. Specifically, the dividend yield for utility stocks has been higher recently, caused by drops in the stock price. These utility stock price declines have been caused by concerns about the economy, utility sales, and reductions to capital programs which will slow rate base growth. These factors would limit future earnings and dividend growth. In contrast, the growth component in the DCF result still reflects extraordinarily robust growth outlooks. Therefore, the current market assessments for growth for utilities appear to contradict those growth outlooks reflected in security analysts' projections. Further, the growth rate included in the DCF model is also not sustainable over an indefinite period of time. Therefore, reliability of the constant growth DCF model is at very best, problematic. Therefore, I do not recommend relying on the results of the constant growth DCF study in this case.

Q. WHY DO YOU BELIEVE THAT THE CURRENT DIVIDEND YIELD IS ABNORMALLY HIGH RELATIVE TO HISTORICAL STANDARDS?

A. As shown on ICNU-CUB/306, the historical dividend yield over the last five years (2004-2008) is in the range of 3.54% to 4.15%, with an average of 3.84%. This is significantly lower than the current dividend yield of 5.32%.

The current dividend yield is driven by the current market uncertainty. Like the market in general, stock prices of the proxy group companies have decreased, which in turn have increased the proxy group dividend yield. Part of the cause for the decline in utility stock price relates to the expectation of reduced growth, or more uncertain future growth. Future growth is impacted by the current economic environment, which has impacted customer sales growth and caused many utilities to reduce capital programs to conserve cash. These factors result in a reduction to growth in rate base and the related growth in earnings and dividends.

Indeed, *Value Line* observed this in its most recent comment on the electric utility industry. *Value Line* recognized utility stocks' deterioration based on economic conditions as follows:

> Since our last review, electric utility stocks as a whole have continued to struggle, based on share-price performance. Many utilities have been hampered by higher capital costs and weaker generation margins stemming from lower demand and a sharp decline in energy prices. Within the Eastern utility group, top losers included *Central Vermont* (-32%), Washington, DC.-based *Pepco Holdings* (-26%), and Ohio-based *First Energy Group* (-22%). Notable gainers included Florida-based *FPL*

> *Group* (15%) and New Jersey-based *Public Service Enterprise Group* (10%).[10/]

Value Line also has recognized that dividend growth will likely slow after a rather robust pace that took place through calendar year 2008. *Value Line* also stated as follows:

> Dividends have been increasing at a rapid pace since 2002, reflecting relatively healthy balance sheets throughout the industry. In fact, last year 61% of electric utilities raised their dividend, 33% reported no change, 2% reinstated theirs, 2% lowered them, and only 2% are not paying them at all. In any industry these statistics would be viewed as quite favorable. <u>But, 2008 actually marked the slowing of a trend for the electric utility industry, in which the percentage of dividend increases declined. The reversal is attributable to deteriorating economic conditions, elevated capital spending, and higher debt-to-capitalization ratios</u>. Despite this, many utilities are still sporting attractive yields.[11/]

Q. HOW DO THE PROXY GROUP'S PROJECTED GROWTH RATES COMPARE TO HISTORICAL ACTUAL GROWTH AND CONTEMPORARY PROJECTED NOMINAL GROSS DOMESTIC PRODUCT ("GDP") GROWTH AND INFLATION RATES?

A. As shown in ICNU-CUB/307, the historical growth of the proxy group's dividend (columns 1 and 2) is lower than the historical nominal GDP growth (columns 7 and 8). Over the last 5 and 10 years, my proxy group's dividend growth was lower than the actual inflation growth (columns 4 and 5) and well beneath the actual growth of nominal GDP (columns 7 and 8).

This historical perspective confirms the robust outlook for earnings growth over the next three to five years and supports my contention that current three- to five-year earnings growth projections are not reasonable estimates of sustainable long-term growth.

[10/] *The Value Line Investment Survey Ratings & Reports*, "Electric Utility (East) Industry," May 29, 2009 at 148.

[11/] <u>Id.</u> (emphasis added).

Q. WHY DO YOU BELIEVE THE PROXY GROUP'S THREE- TO FIVE-YEAR GROWTH RATE IS IN EXCESS OF A LONG-TERM SUSTAINABLE GROWTH?

A. The three- to five-year growth rate of the proxy group exceeds the growth rate of the overall U.S. economy. As developed below, the consensus of published economists projects that the U.S. GDP will grow at a rate of no more than 5.1% over the next 5 to 10 years. A company cannot grow, indefinitely, at a faster rate than the market in which it sells its products. The U.S. economy, or GDP, growth projection represents a ceiling, or high-end, sustainable growth rate for a utility over an indefinite period of time.

Q. WHY IS THE GDP GROWTH PROJECTION CONSIDERED A CEILING GROWTH RATE FOR A UTILITY?

A. Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the overall economy. Utilities' earnings/dividend growth is created by increased utility investment or rate base. Utility plant investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth, and sales growth in turn is tied to economic growth in their service areas. The Energy Information Administration ("EIA") has observed that utility sales growth is less than U.S. GDP growth, as shown in Exhibit ICNU-CUB/308. Utility sales growth has lagged behind GDP growth. Hence, nominal GDP growth is a very conservative, albeit overstated, proxy for electric utility sales growth, rate base growth, and earnings growth. Therefore, GDP growth is a reasonable proxy for the highest sustainable long-term growth rate of a utility.

Q. IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE GROWTH OF THE U.S. GDP?

A. Yes. This concept is supported in both published analyst literature and academic work. Specifically, in a textbook entitled "Fundamentals of Financial Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).[12/]

Also, Morningstar's *Stocks, Bonds, Bills and Inflation 2009 Yearbook Valuation Edition* tracked dividends of the stock market in comparison to GDP growth over the period 1926 through the end of 2008.[13/] Based on that study, the authors found that earnings and dividends for the market have historically grown in tandem with the overall economy. It is important to note that the growth of companies included in the overall market will normally be higher than that of utility companies. These non-utility companies achieve a higher level of growth because they retain a larger percentage of their earnings and pay out a much smaller percentage of their earnings as dividends. Retaining higher percentages of total earnings fuels stronger growth for these non-utility companies. Since the market in general grows at the overall GDP growth rate, it is very conservative to assume that utility companies could achieve this same level of sustained growth without a material reduction in their dividend payout ratios. As such, using the

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12/ "Fundamentals of Financial Management," Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298.

13/ *Stocks, Bonds, Bills and Inflation 2009 Yearbook Valuation Edition* (Morningstar, Inc.) at 67.

GDP as a maximum sustainable growth rate is a very conservative and high-end estimate for utility companies.

<u>II.6.</u> **<u>Sustainable Growth DCF</u>**

Q. IS THERE A WAY OF DEVELOPING A DCF ESTIMATE USING A SUSTAINABLE LONG-TERM GROWTH RATE?

A. Yes. This can be developed using an internal growth rate or sustainable growth for the companies included in the proxy group using *Value Line*'s three- to five-year earnings and dividends projections and estimated earned return on equity. An internal growth rate methodology estimates the sustainable growth rate based on the percentage of the utility's earnings that are retained in the company and reinvested in utility plant and equipment. These reinvested earnings increase the earnings base and will increase the earned return on equity when those additional earnings are put into service, and the company is allowed to earn its authorized return on the additional investment.

The internal growth methodology is tied to the percentage of earnings retained in the company and not paid out as dividends. The earnings retention ratio is 1 minus the dividend payout ratio. As the payout ratio declines, the earnings retention ratio increases. An increased earnings retention ratio will fuel stronger growth because the business funds more investments with retained earnings. As shown in Exhibit ICNU-CUB/309, *Value Line* projects the proxy group to have a declining dividend payout ratio over the next three to five years. These dividend payout ratios and earnings retention ratios can then be used to develop a sustainable long-term earnings retention growth rate to help gauge whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time.

As shown in Exhibit ICNU-CUB/310, the average sustainable growth rate for the proxy group using this internal growth rate model is 5.05%.

Using the proxy group average growth rate of 6.06% and a three- to five-year projected dividend payout ratio of 55.71% would require an earned return on book equity of 13.68%[14] to support a long-term sustainable growth rate of 6.06%. In comparison, *Value Line* is projecting a group average return on book equity of 11.17%. Id. This information supports my conclusion that current analysts' three- to five-year earnings growth projections are not sustainable and will decline over time.

Q. WHAT IS A CONSTANT GROWTH DCF ESTIMATE USING THIS SUSTAINABLE LONG-TERM GROWTH RATE?

A. A DCF estimate based on this sustainable growth rate is developed in Exhibit ICNU-CUB/311. As shown there, a sustainable growth DCF analysis produces a group average DCF result of 10.62%.

The sustainable growth DCF result is based on the dividend and price data used in my constant growth DCF study (using analyst growth rates) and the sustainable growth rate discussed above and developed in Exhibit ICNU-CUB/310.

II.7. Multi-Stage Growth DCF Model

Q. HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A. Yes. My first constant growth DCF is based on consensus analysts' growth rate projections, so it is a reasonable reflection of rational investment expectations over the next three to five years. The limitation on the constant growth DCF model is that it cannot reflect a rational expectation that a period of high/low short-term growth can be followed by a change in growth to a rate that is more reflective of long-term sustainable

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[14] 6.06% ÷ (1 – 55.71%).

growth. Hence, I performed a multi-stage growth DCF analysis to reflect this outlook of changing growth expectations.

Q. PLEASE DESCRIBE YOUR MULTI-STAGE GROWTH DCF MODEL.

A. The multi-stage growth DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period, which consists of the first five years; (2) a transition period, which consists of the next five years (6 through 10); and (3) a long-term growth period, starting in year 11 through perpetuity.

For the short-term growth period, I relied on the consensus analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor, which reflects the difference between the analysts' growth rates and the GDP growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable growth rate for a utility company as proxied by the consensus analysts' projected growth for the U.S. GDP of 5.1%.

Q. WHAT DO YOU BELIEVE IS A REASONABLE SUSTAINABLE LONG-TERM GROWTH RATE?

A. A reasonable growth rate that can be sustained in the long run should be based on consensus analysts' projections. *Blue Chip Economic Indicators* publishes consensus GDP growth projections twice a year. Based on its latest issue, the consensus economists' published 5- to 10-year GDP growth rate outlook is 5.2% to 4.9%.[15/]

Therefore, I propose to use the consensus economists' projected 5- and 10-year GDP consensus growth rate of 5.1%, as published by *Blue Chip Economic Indicators,* as

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15/ *Blue Chip Economic Indicators*, March 10, 2009 at 15.

an estimate of sustainable long-term growth. This consensus GDP growth forecast represents the most likely views of market participants because it is based on published economist projections.

Q. WHAT STOCK PRICE, DIVIDEND AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE GROWTH DCF ANALYSIS?

A. I relied on the same 13-week stock price and the most recent quarterly dividend payment discussed above. For stage one growth, I used the consensus analysts' growth rate projections discussed above in my constant growth DCF model. The transition period begins in year 6 and ends in year 10. For the long-term sustainable growth rate starting in year 11, I used 5.1%, the average of the consensus economists' 5- to 10-year projected nominal GDP growth rate (5.2% to 4.9%).

Q. WHAT ARE THE RESULTS OF YOUR MULTI-STAGE GROWTH DCF MODEL?

A. As shown in Exhibit ICNU-CUB/312, the average multi-stage growth DCF return on equity for the proxy group is 10.96%.

Q. PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A. The results from my DCF analyses are summarized in the table below:

TABLE 3

Summary of DCF Results

Description	Proxy Group
Constant Growth DCF Model (Analysts' Growth)	11.68%
Constant Growth DCF Model (Sustainable Growth)	10.62%
Multi-Stage Growth DCF Model	10.96%
DCF Return[16/]	10.80%

16/ (10.62% + 10.96%) / 2.

The average of my DCF studies, excluding my analysts' constant growth DCF model for the reasons discussed above, is 10.80%.

For the reasons set forth above, I believe the DCF return produces abnormally high results given the market data supporting the DCF estimate at this time. As noted above, the dividend yield component of the DCF model reflects significant declines to stock prices over the last few months that were largely caused by the economic downturn and financial distress caused by recent capital markets. The economic downturn and these stock price declines have together contributed to the market's expectations of uncertain sales growth outlooks and reduced capital expenditure programs, which will limit utilities' earnings and dividend growth. In significant contrast, the growth component of the DCF model still reflects robust growth outlooks that are considerably higher than historical achieved growth for utility dividends and earnings over the last five and ten years. As such, the major components of the DCF reflect opposite outlooks: (1) the dividend yield component reflects constrained growth outlooks; and (2) the growth component reflects robust growth outlooks. Because of these uncertain and apparent contradictory outlooks, I recommend the Commission place minimal or no weight on the results of the DCF study at this time.

II.8. Risk Premium Model

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

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

This risk premium model is based on two estimates of an equity risk premium. First, I estimated the difference between the required return on utility common equity investments and Treasury bonds. The difference between the required return on common equity and the bond yield is the risk premium. I estimated the risk premium on an annual basis for each year over the period 1986 through first quarter of 2009. The common equity required returns were based on regulatory commission-authorized returns for electric utility companies. Authorized returns are typically based on expert witnesses' estimates of the contemporary investor required return.

The second equity risk premium method is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields. This time period was selected because over the period 1986 through the first quarter of 2009, public utility stocks have consistently traded at a premium to book value. This is illustrated in Exhibit ICNU-CUB/313, where the market to book ratio since 1986 for the electric utility industry was consistently above 1.0. Over this time period, regulatory authorized returns were sufficient to support market prices that at least exceeded book value. This is an indication that regulatory authorized returns on common equity supported a utility's ability to issue additional common stock, without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit ICNU-CUB/314, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.17%. Of the 24 observations, 18 indicated risk premiums fall in the range of 4.40% to 6.08%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity using this methodology.

As shown in Exhibit ICNU-CUB/315, the average indicated equity risk premium over contemporary Moody's utility bond yields was 3.69% over the period 1986 through the first quarter of 2009. The indicated equity risk premium estimates based on this analysis primarily fall in the range of 3.03% to 4.39% over this time period.

Q. DO YOU BELIEVE THAT THIS RISK PREMIUM IS BASED ON A TIME PERIOD THAT IS TOO LONG OR TOO SHORT TO DRAW ACCURATE RESULTS CONCERNING CONTEMPORARY MARKET CONDITIONS?

A. No. Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. Therefore, relying on a relatively long period of time where stock valuations reflect premiums to book value is an indication that the authorized returns on equity and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

The time period I use in this risk premium is a generally accepted period to develop a risk premium study using "expectational" data. Conversely, studies have recommended that use of "actual achieved return data" should be based on very long historical time periods. The studies find that achieved returns over short time periods may not reflect investors' expected returns due to unexpected and abnormal stock price performance. However, these short-term abnormal actual returns would be smoothed over time and the achieved actual returns over long time periods would approximate investors' expected returns. Therefore, it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns.

My risk premium study is based on expectational data, not actual returns, and, thus, need not encompass very long time periods.

Q. BASED ON HISTORICAL DATA, WHAT RISK PREMIUM HAVE YOU USED TO ESTIMATE PACIFICORP'S COST OF EQUITY IN THIS PROCEEDING?

A. The equity risk premium should reflect the relative market perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit ICNU-CUB/316. On that exhibit, I show the yield spread between utility bonds and Treasury bonds over the last 29 years. As shown in this exhibit, the 2008 utility bond yield spreads over Treasury bonds for "A" rated and "Baa" rated utility bonds are 2.23% and 2.93%, respectively. The utility bond spreads over Treasury bonds for "A" and "Baa" rated utility bonds for the first quarter of 2009 are 2.92% and 4.43%, respectively. These utility bond yield spreads over Treasury bond yields are much higher than the 29-year average spreads of 1.64% and 2.05%, respectively.

While the yield spreads for 2008 and first quarter 2009 reflect unusually large spreads, the market has started to improve and these spreads have started to decline. For example, the 13-week average "A" rated utility bond yield has subsided relative to the end of 2008 and beginning of 2009, down to around 6.5%. This utility bond yield when compared to the projected Treasury bond yield of 4.6%, implies a yield spread of around

1.9% which is more comparable to the 29-year average spread for "A" utility bonds than early 2009 spreads.

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

A. I added a projected long-term Treasury bond yield to my estimated equity risk premium over Treasury yields. *Blue Chip Financial Forecasts* projects the 30-year Treasury bond yield to be 4.60%, and a 10-year Treasury bond yield to be 3.8%.[17/] Using the projected 30-year bond yield of 4.60% and a Treasury bond risk premium of 4.40% to 6.08%, as developed above, produces an estimated common equity return in the range of 9.00% to 10.68%, with a midpoint of 9.84%. This produces a recommended return on equity of 9.84%.

I next added my equity risk premium over utility bond yields to a current 13-week average yield on "A" rated utility bonds for the period ending June 19, 2009 of 6.46. ICNU-CUB/317, Gorman/1. Adding the utility equity risk premium of 3.03% to 4.39%, as developed above, to a "A" rated bond yield of 6.46%, produces a cost of equity in the range of 9.49% to 10.85%, with a midpoint of 10.17%. As shown on page 2 of ICNU-CUB/317, "A" rated utility bond yields reached very high levels during late October through December 2008, but they have recovered and converged to the normalized levels observed in the past.

My risk premium analyses produce a return estimate in the range of 9.84% to 10.17%, with a midpoint estimate of 10.00%.

17/ *Blue Chip Financial Forecasts*, June 1, 2009 at 2.

II.9. Capital Asset Pricing Model ("CAPM")

Q. PLEASE DESCRIBE THE CAPM.

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

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

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

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

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

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

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

A. As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 4.60%.[18/] The current 30-year bond yield is 3.5%. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 4.60% for my CAPM analysis.

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

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

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. A Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic or market risks. Consequently, for companies with betas less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

18/ *Blue Chip Financial Forecasts*, June 1, 2009 at 2.

Q. WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A. As shown in Exhibit ICNU-CUB/318, the proxy group average *Value Line* beta estimate is 0.68.

Q. HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATE?

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

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

Morningstar's *Stocks, Bonds, Bills and Inflation 2009 Yearbook* publication estimates the historical arithmetic average real market return over the period 1926 to 2008 as 8.5%. A current consensus analysts' inflation projection, as measured by the Consumer Price Index, is 2.0%.[19/] Using these estimates, the expected market return is 10.67%.[20/] The market premium then is the difference between the 10.67% expected market return, and my 4.6% risk-free rate estimate, or 6.07%.

The historical estimate of the market risk premium was also estimated by Morningstar in *Stocks, Bonds, Bills and Inflation 2008 Yearbook*. Over the period 1926 through 2008, Morningstar's study estimated that the arithmetic average of the achieved total return on the S&P 500 was 11.70%, and the total return on long-term Treasury

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19/ *Blue Chip Financial Forecasts*, June 1, 2009 at 2.

20/ $\{ [(1 + 0.085) * (1 + 0.020)] - 1] \} * 100.$

bonds was 6.10%. The indicated equity risk premium is 5.60% (11.70% - 6.10% = 5.60%).

Q. HOW DOES YOUR ESTIMATED MARKET RISK PREMIUM RANGE COMPARE TO THAT ESTIMATED BY MORNINGSTAR?

A. Morningstar estimates a forward-looking market risk premium based on actual achieved data from the historical period of 1926 through year-end 2008. Using this data, Morningstar estimates a market risk premium derived from the total return on large company stocks (S&P 500), less the income return on Treasury bonds. The total return includes capital appreciation, dividend or coupon reinvestment returns, and annual yields received from coupons and/or dividend payments. The income return, in contrast, only reflects the income return received from dividend payments or coupon yields. Morningstar argues that the income return is the only true risk-free rate associated with the Treasury bond and is the best approximation of a truly risk-free rate. While I disagree with this assessment from Morningstar, because it does not reflect a true investment option available to the marketplace and therefore does not produce a legitimate estimate of the expected premium of investing in the stock market versus that of Treasury bonds. Nevertheless, I will use Morningstar's conclusion to show the reasonableness of my market risk premium estimates.

Morningstar's analysis indicates that a market risk premium falls somewhere in the range of 5.7% to 6.5%. This range is based on several methodologies. First, Morningstar estimates a market risk premium of 6.5% based on the difference between the total market return on common stocks (S&P 500) less the income return on Treasury bond investments. Second, Morningstar found that if the New York Stock Exchange (the "NYSE") was used as the market index rather than the S&P 500, that the market risk premium would be 6.3% and not 6.5%. Third, if only the two deciles of the largest companies included in the NYSE were considered, the market risk premium would be 5.8%.[21/]

Finally, Morningstar found that the 6.5% market risk premium based on the S&P 500 was impacted by an abnormal expansion of price-to-earnings ("P/E") ratios relative to earnings and dividend growth during the period 1980 through 2001. Morningstar believes this abnormal P/E expansion is not sustainable. Therefore, Morningstar adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings. Based on this alternative methodology, Morningstar published a long-horizon supply-side market risk premium of 5.7%.[22/]

Thus, based on all of Morningstar's estimates, the market risk premium falls somewhere in the range of 5.7% to 6.5%. This range supports my use of a 6.50% market risk premium in my CAPM study.

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A. As shown in Exhibit ICNU-CUB/319, based on my historical market risk premium of 5.6% and prospective market risk premium of 6.07%, a risk-free rate of 4.60%, and a beta of 0.68, my CAPM analysis produces a return in the range of 8.41% to 8.73%, with a midpoint of 8.57%, rounded up to 8.60%.

Q. DO YOU HAVE ANY GENERAL COMMENTS ON THE RESULTS OF YOUR CAPM ANALYSIS?

A. Yes. I believe my CAPM study is also impacted by the distressed financial market. The impact on the financial market has resulted in a decline in the market risk premium that

21/ Morningstar observes that the S&P 500 and the NYSE Decile 1-2 are both large capitalization benchmarks. Morningstar, Inc. *Ibbotson SBBI 2009 Valuation Yearbook* at 56 and 57.

22/ *Id.* at 67-69.

was largely caused by a significant decline in stock market valuations and increase in Treasury bond valuations at the end of 2008. The market risk premium has been around 6.5% over the last several years, but declined to 5.6% at year-end 2008. I do not believe this reduced market risk premium is sustainable. Therefore, I recommend minimal or no weight be placed on the CAPM return estimate at this time.

II.10. Return on Equity Summary

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

A. Based on my analyses, I estimate PacifiCorp's current market cost of equity to be 10.0%.

TABLE 4

Return on Common Equity Summary

Description	Results
DCF	10.80%
Risk Premium	10.00%
CAPM	8.60%

My recommended return on equity range is 9.60% to 10.40%. For the reasons set forth above, based on the unstable market conditions that exist today, I believe the DCF results are abnormally high, and the CAPM return estimate is abnormally low. Therefore, I have developed a range based on a method of mitigating the extreme high and low return on equity estimates. I believe this is necessary in order to approximate a reasonable return on equity that provides fair compensation for investment risk over time and is not distorted by the abnormal and depressed market conditions.

The high end of the range was based on the approximate midpoint DCF and Risk Premium range, and the low end was based on the approximate midpoint of the DCF and CAPM range. The midpoint is equal to the Risk Premium estimate.

II.11. Financial Integrity

Q. WILL YOUR RECOMMENDED OVERALL RATE OF RETURN SUPPORT AN INVESTMENT GRADE BOND RATING FOR PACIFICORP?

A. Yes. I have reached this conclusion by comparing the key credit rating financial ratios for PacifiCorp at its proposed capital structure and my return on equity to S&P's benchmark financial ratios using S&P's new credit metric ranges. In addition, I compared PacifiCorp's key credit financial ratios to S&P benchmark financial ratios, the old S&P credit metric ranges for an "A" rated utility, and a "BBB" rated utility with a business profile score ("BPS") of '5,' PacifiCorp's rating under S&P's old credit metric benchmarks.

Q. WHY ARE YOU COMPARING YOUR CREDIT METRIC CALCULATIONS TO S&P'S NEW AND OLD CREDIT METRIC GUIDELINES?

A. S&P's new credit metrics are not as transparent and do not clearly identify utility-specific credit metric guidance ranges based on S&P business risk assessment. Specifically, S&P has not published a range, that I am aware of, where it sets out specific credit metric ranges for a utility with an "Aggressive" financial risk rating, and a business risk rating score of "Excellent," PacifiCorp's current rating. However, S&P has published guidelines which appear to be generally reflective of credit metrics at various credit rating levels. In order to more clearly identify credit metric ranges that are appropriate to support PacifiCorp's credit ratings, I will use both S&P's old and new credit metric benchmarks.

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

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

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

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

A. I calculated each of S&P's financial ratios based on PacifiCorp's cost of service for retail operations. While S&P would normally look at total MidAmerican Energy Holding Company consolidated financial ratios in its credit review process, my investigation in this proceeding is to judge the reasonableness of my proposed cost of capital for rate setting in PacifiCorp's utility operations. Hence, I am attempting to determine whether the rate of return and related cash flow generation opportunity reflected in my proposed utility rates for PacifiCorp will support its investment grade bond ratings and financial integrity.

Q. DID YOU INCLUDE ANY OFF-BALANCE SHEET DEBT?

A. Yes. As shown in ICNU-CUB/320, Gorman/3, I estimated off-balance sheet debt equivalents of $125.8 million attributed to PacifiCorp's operating leases and PPAs.

Q. HOW DID YOU ESTIMATE PACIFICORP'S OFF-BALANCE SHEET DEBT?

A. The off-balance sheet debt is shown on ICNU-CUB/320. First, I developed a PacifiCorp allocator, which is the ratio of PacifiCorp's Oregon rate base as of June 2008 divided by total Company rate base for the same period.

Second, I obtained PacifiCorp's total Company off-balance sheet debt and associated imputed interest and amortization expenses from the S&P report provided by the Company in response to OPUC DR 16. Then, I applied the PacifiCorp allocator to PacifiCorp's total Company off-balance sheet debt and associated imputed interest and amortization expense.

Q. PLEASE DESCRIBE THE RESULTS OF THIS CREDIT METRIC ANALYSIS BASED ON PACIFICORP'S PROPOSED CAPITAL STRUCTURE AND A COMPOSITE 10.0% RETURN ON EQUITY.

A. The S&P financial metric calculations for PacifiCorp are developed in ICNU-CUB/320, Gorman/1-2. As shown on this exhibit, based on an equity return of 10.0%, PacifiCorp will be provided an opportunity to produce an FFO to debt interest expense of 4.6x. This FFO to interest coverage ratio is slightly above the high end of S&P's old benchmark ratio guideline of 3.8x to 4.5x[23/] for an "A" rated utility company with a business profile score of '5,' and is well above (stronger than) S&P's new guideline range of 2.0x to 3.5x.[24/] This ratio supports a credit rating of a strong "A."

PacifiCorp's retail operations FFO to total debt coverage at a 10.0% equity return would be 23%, which is within S&P's old credit metric guideline range of 22% to 30%

23/ Standard & Poor's: "Assessing U.S. Vertically Integrated Utilities? Business Risk Drivers," September 14, 2006.

24/ Standard & Poor's: "U.S. Utilities Rating Analysis Now Portrayed in the S&P Corporate Ratings Matrix," November 30, 2007.

for an "A" bond rating and within the new metric guideline range of 10% to 30%. The FFO/total debt ratio will support a weak "A" rated investment grade bond rating.

Finally, PacifiCorp's total debt ratio to total capital is 50%. This is at the high end of S&P's "A" rated utility old guideline range of 42% to 50%, which supports a weak "A" or a strong "BBB" credit rating.

With my proposed capital structure and return on equity of 10.0%, PacifiCorp's financial credit metrics are supportive of an "A" utility bond rating. Therefore, my recommended return on equity is consistent with the overall financial and business risk underlying PacifiCorp's current bond rating, will fairly compensate PacifiCorp's investors, and will support the Company's financial integrity.

<u>II.12.</u> <u>Response to PacifiCorp Witness Dr. Samuel Hadaway</u>

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

A. PacifiCorp is proposing to set rates based on a return on equity of 11.0%. PacifiCorp's return on equity proposal is based on the analysis and judgment of Dr. Samuel Hadaway. Dr. Hadaway's results are summarized at page 36 of his direct testimony. PPL/200, Hadaway/36.

Q. DO DR. HADAWAY'S METHODOLOGIES SUPPORT HIS 11.00% RETURN ON EQUITY FOR HIS PROXY GROUP?

A. No. As discussed in detail below, reflecting current market data and properly applying his models, Dr. Hadaway's own analyses would support a return on equity in the range of 9.9% to 10.3%. These adjustments to Dr. Hadaway's return on equity estimates support my recommended return on equity of 10.0%.

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

A. Dr. Hadaway develops his return on common equity recommendation using three versions of the DCF model, and two utility risk premium analyses. Further, he tests his results using a risk premium analysis conducted by Ibbotson Associates. I have summarized Dr. Hadaway's results below in Table 5 under column 1. Under column 2, I show the results of Dr. Hadaway's analyses adjusted for updated data and more reasonable application of the models.

As shown below in Table 5, using consensus economists' projection of GDP growth rather than Dr. Hadaway's inflated GDP growth estimates, his own DCF analyses would support a return on equity for PacifiCorp in the range of 10.1% to 10.4%, with a midpoint of 10.3%. Proper adjustments to Dr. Hadaway's utility and Ibbotson risk premium estimates to reflect the unadjusted equity risk premium and PacifiCorp's below market risk would reduce this estimate from 10.9% to 9.9%. Therefore, Dr. Hadaway's return on equity estimate with reasonable adjustments will produce a return on equity for PacifiCorp in the range of 9.9% to 10.3%, with a midpoint of 10.1%.

TABLE 5

Summary of Dr. Hadaway's ROE Estimate

Description	Hadaway Results (1)	Adjusted Hadaway Results (2)
Electric DCF Analysis		
Constant Growth (Analysts' Growth)	11.4% - 11.6%	11.4% - 11.6%
Constant Growth (GDP Growth)	11.2% - 11.5%	10.1% - 10.4%
Multi-Stage Growth Model	11.0% - 11.1%	10.1% - 10.2%
Reasonable DCF Range	11.0% - 11.6%	10.1% - 10.4%*
Risk Premium Analysis		
Forecasted Utility Debt + Equity Risk Premium	11.03%	9.90%
Current Utility Debt + Equity Risk Premium	10.73%	9.90%
Ibbotson Risk Premium Analysis	10.90%	9.46%
Risk Premium Estimate	10.90%	9.90%
Midpoint ROE	11.0%	10.1%

Source: PPL/200, Hadaway/36.

*Excluding Dr. Hadaway's analysts' constant growth DCF model.

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

A. Dr. Hadaway's adjusted constant growth DCF analysis is shown in ICNU-CUB/321, Gorman/2. As shown on that exhibit, Dr. Hadaway's constant growth DCF analysis is based on a recent stock price, an annualized dividend and an average of three growth rates: (1) *Value Line*; (2) Zacks; and (3) Thomson.

Q. ARE DR. HADAWAY'S DCF ESTIMATES RELIABLE?

A. For at least two reasons, no. First, Dr. Hadaway's constant growth DCF based on analyst growth rates produces excessive return estimates for the same reasons discussed above concerning my DCF studies. That is, Dr. Hadaway's analyst growth DCF study is based on an abnormally high dividend yield in the range of 5.05% to 5.34% and growth rate estimates in the range of 6.20% to 6.40%, which are not sustainable in the long-run. Like mine, Dr. Hadaway's DCF studies represent contradictory market growth outlooks, as discussed above. Therefore, the Commission should give little weight to Dr. Hadaway's DCF analyses.

Second, his GDP growth rate used in his constant growth and multi-stage growth models is based on an inflated GDP growth rate of 6.2%. This GDP growth is excessive and not reflective of current market expectations.

Q. HOW DID DR. HADAWAY DEVELOP HIS GDP GROWTH RATE?

A. He states that the GDP growth rate is based on the achieved GDP growth over the last 10, 20, 30, 40, 50, and 60-year periods. Dr. Hadaway's projected GDP growth rate is unreasonable. Historical GDP growth over the last 20 and 40-year periods was strongly influenced by the actual inflation rate experienced over that time period.

Q. WHY IS DR. HADAWAY'S DCF ESTIMATE EXCESSIVE IN COMPARISON TO THAT OF PUBLISHED MARKET ANALYSTS?

A. The consensus economists' projected GDP growth rate is much lower than the GDP growth rate used by Dr. Hadaway in his DCF analysis. A comparison of Dr. Hadaway's GDP growth rate and consensus economists' projected GDP growth over the next five and ten years is shown below in Table 6. As shown in this table, Dr. Hadaway's GDP rate of 6.2% reflects real GDP of 3.2% and an inflation adjusted GDP of 3.0%. However, consensus economists' projections of nominal GDP include GDP inflation projections over the next five and ten years of 2.1%, and 2.3%, respectively.[25/]

[25/] *Blue Chip Economic Indicators*, March 10, 2009, at 15.

As is clearly evident in the table below, Dr. Hadaway's historical GDP growth reflects historical inflation, which is much higher than, and not representative of, consensus market expected forward-looking inflation.

TABLE 6

GDP Projections

Description	GDP Inflation	Real GDP	Nominal GDP
Dr. Hadaway	3.0%	3.2%	6.2%
Consensus 5-Year Projection	2.1%	3.1%	5.2%
Consensus 10-Year Projection	2.3%	2.6%	4.9%

Source: Blue Chip Economic Indicators, March 10, 2009, at 15.

As such, Dr. Hadaway's 6.2% nominal GDP growth rate is not reflective of consensus market expectations and should be rejected.

Q. HOW WOULD DR. HADAWAY'S DCF ANALYSES CHANGE IF CURRENT MARKET-BASED GDP GROWTH RATE PROJECTIONS ARE INCLUDED IN HIS ANALYSIS RATHER THAN HIS EXCESSIVE GDP GROWTH RATE?

A. As shown in Exhibit ICNU-CUB/321, I updated Dr. Hadaway's DCF analyses using a GDP growth rate of 5.1%. This GDP growth rate is the consensus economist's average five- and 10-year projected growth rate of the GDP as published in the Blue Chip Economic Indicators on March 10, 2009. As shown in Exhibit ICNU-CUB/321, using this consensus economist's projected GDP growth rate reduces Dr. Hadaway's DCF results.

TABLE 7

Adjusted Hadaway DCF

Description	Range Average Hadaway DCF	Adjusted DCF
Constant Growth (Analysts' Growth)	11.5%	11.5%
Constant Growth (GDP Growth)	11.4%	10.3%
Multi-Stage Growth Model	11.1%	10.2%
Average	11.3%*	10.3%*

* Excluding Dr. Hadaway's analysts' growth DCF model.

Q. WITH THESE ADJUSTMENTS, WHAT RETURN ON EQUITY WOULD DR. HADAWAY'S DCF MODELS SUGGEST IS A FAIR RETURN ON EQUITY FOR PACIFICORP IN THIS PROCEEDING?

A. Reflecting a consensus economists' GDP growth forecast and excluding Dr. Hadaway's analysts' growth DCF model would produce an average DCF result of 10.3%.

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

A. Dr. Hadaway's utility bond yield versus authorized return on common equity risk premium is shown in Exhibit PPL/206 and Exhibit PPL/207. As shown in these exhibits, Dr. Hadaway estimated an annual equity risk premium by subtracting Moody's average bond yield from the electric utility regulatory commission authorized return on common equity over the period 1980 through 2008. Based on this analysis, Dr. Hadaway estimates an average indicated equity risk premium over current utility bond yields of 3.19%.

Dr. Hadaway then adjusts this average equity risk premium using a regression analysis based on an expectation that there is an ongoing inverse relationship between interest rates and equity risk premiums. Based on this regression analysis, Dr. Hadaway increases his equity risk premium from 3.19%, up to 4.12% and 4.33% relative to current and projected "A" bond yield of 6.91% and 6.40%, respectively. He then adds these inflated equity risk premiums to the projected and current "A" rated utility bond yield of 6.91% and 6.40% to produce a return on equity of 11.03% and 10.73%, respectively.

Q. ARE DR. HADAWAY'S UTILITY RISK PREMIUM ANALYSES REASONABLE?

A. No. Dr. Hadaway develops a forward-looking risk premium model, relying on forecasted interest rates and volatile utility spreads, which are highly uncertain and produce inaccurate results. Further, Dr. Hadaway adjusts his equity risk premium of 3.19% to reflect the inverse relationship between interest rates and utility risk premiums. This adjustment is inappropriate and not consistent with academic literature that finds that this relationship should change with risk changes and not simply changes to interest rates.

Q. DOES DR. HADAWAY'S RISK PREMIUM ANALYSIS SUPPORT A RETURN ON EQUITY IN THE RANGE OF 11.03% TO 10.73%?

A. No. His equity risk premium estimates of 4.12% and 4.33% are overstated. The common equity risk premium over the period 1986 to Q1, 2009 is approximately 3.69% as shown in Exhibit ICNU-CUB/315.

Q. DO YOU HAVE ANY COMMENTS CONCERNING DR. HADAWAY'S FORECASTED UTILITY YIELD OF 6.91%?

A. Yes. Dr. Hadaway develops his forecasted utility yield based on the 3-month historical spread of A-rated utility bond yields and 30-year Treasury yields of 3.21% added to his projected long-term Treasury yield of 3.7%. This approach is unreasonable for two reasons. First, Dr. Hadaway relies on projected interest rates. The accuracy of his projections are highly problematic. Indeed, while interest rates have been projected to increase over the last several years, those increased interest rate projections have turned out to be wrong. Second, Dr. Hadaway's reliance on the 3-month historical spread is inappropriate in light of current economic conditions and produces overstated results. Thus, the Commission should reject Dr. Hadaway's risk premium based on forecasted utility bond yields.

Q. WHY DO YOU BELIEVE THAT THE ACCURACY OF FORECASTED INTEREST RATES IS HIGHLY PROBLEMATIC?

A. This is clearly evident by a review of projected changes to interest rates made over the last several years, in comparison to how accurate these projections turned out to be. This analysis clearly illustrates that observable interest rates today are as accurate as are economists' consensus projections of future interest rates.

An analysis supporting this conclusion is illustrated in Exhibit ICNU-CUB/322. On this exhibit, under Columns 1 and 2, I show the actual market yield at the time a projection is made for Treasury bond yields two years in the future. In Column 1, I show the actual Treasury yield and, in Column 2, I show the projected yield two years out.

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

As shown in this exhibit, over the last several years, economists have been consistently projecting increases to interest rates. However, as demonstrated under Column 5, those yield projections have turned out to be overstated in virtually every case. Indeed, actual Treasury yields have decreased or remained flat over the last five years, rather than increase as the economists' projections indicated.

This review of the experience with projected interest rates clearly illustrates that interest rate projection accuracy is highly problematic. Indeed, current observable interest rates are just as likely a reasonable projection of future interest rates as are economists' projections.

Q. WHY DO YOU BELIEVE THAT DR HADAWAY'S RELIANCE ON THE 3-MONTH SPREAD IS UNREASONABLE?

A. In light of current economic conditions, the spread between the A-rated utility bond yields and the 30-year Treasury bond has significantly increased. Historically, utility yields moved in tandem with Treasury yields, as shown in Exhibit ICNU-CUB/317. However, the current financial crisis caused the utility yields and Treasury yields to move in opposite directions. Investors changed their risk tolerance and the utility yields have significantly increased relative to historical standards, while the Federal Reserve tried stimulating the economy by lowering the interest rates. In fact, as shown in Exhibit ICNU-CUB/323, in October and November 2008, the spread was over 4.0%, which is higher than historical standards. This high utility spread reflected significant financial distress caused by factors external to the electric utility industry. Specifically, at that time, Lehmann Brothers Investment Bank filed for Chapter 11, which put corporate bonds in distress since it was such a major marketer of corporate bonds, and the impacts of the banking crisis in the U.S. started to come into focus. While "A" rated utility yields have recovered, the market is still volatile. Therefore, relying on the 3-month historical yield spread is based on a highly volatile market and it will lead to unreliable results.

Q. WHY IS DR. HADAWAY'S USE OF A SIMPLE INVERSE RELATIONSHIP BETWEEN INTEREST RATES AND EQUITY RISK PREMIUMS NOT REASONABLE?

A. Dr. Hadaway's belief that there is a simplistic inverse relationship between equity risk premiums and interest rates is not supported by academic research. While academic studies have shown that, in the past, there has been an inverse relationship with these variables, researchers have found that the relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, and not simply changes to interest rates.[26/]

In the 1980s, equity risk premiums were inversely related to interest rates, but that was likely attributable to the interest rate volatility that existed at that time. Interest rate volatility currently is much lower than it was in the 1980s.[27/] As such, when interest rates were more volatile, the relative perception of bond investment risk increased relative to the investment risk of equities. This changing investment risk perception caused changes in equity risk premiums.

In today's marketplace, interest rate variability is not as extreme as it was during the 1980s. Nevertheless, changes in the perceived risk of bond investments relative to equity investments still drive changes in equity premiums. However, a relative investment risk differential cannot be measured simply by observing nominal interest rates. Changes in nominal interest rates are highly influenced by changes to inflation outlooks, which also change equity return expectations. As such, the relevant factor

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26/ "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," Robert S. Harris and Felicia C. Marston, *Journal of Applied Finance*, Volume 11, No. 1, 2001 and "The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management*, Spring 1985.

27/ Morningstar SBBI, 2009 Yearbook at 95-96.

needed to explain changes in equity risk premiums is the relative changes to the risk of equity versus debt securities investments, not simply changes to interest rates. Importantly, Dr. Hadaway's analysis simply ignores investment risk differentials. He bases his adjustment to the equity risk premium exclusively on changes in nominal interest rates. This is a flawed methodology and does not produce accurate or reliable risk premium estimates. His results should be rejected by the Commission.

Q. CAN DR. HADAWAY'S RISK PREMIUM ANALYSES BASED ON CURRENT AND PROJECTED YIELDS BE MODIFIED TO PRODUCE MORE REASONABLE RESULTS?

A. Yes. Eliminating the inverse relationship adjustment to the equity risk premium of 3.19% and relying on Dr. Hadaway's current "A" rated utility yield of 6.40% will result in a return on equity risk premium of 9.59%. Using Dr. Hadaway's 2008 equity risk premium of 3.81% as shown in Exhibits PPL/206 and PPL/207 and his current "A" rated utility yield of 6.40% will result in a return of 10.21%. Therefore, Dr. Hadaway's risk premium will be in the range of 9.59% to 10.21%, with a midpoint of 9.90%.

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

A. Yes. Dr. Hadaway compared his utility risk premium analysis to studies performed by Ibbotson Associates. Dr. Hadaway states that Ibbotson Associates studied the return on common stocks versus corporate bonds for the period 1926 through 2007. The Ibbotson study found that the arithmetic mean risk premium was 6.1%, and the geometric mean return was 4.5%. He states that using the geometric mean return of 4.5%, and his "A" utility bond current yield of 6.40%, would produce an equity return of 10.90% for PacifiCorp. PPL/200, Hadaway/36.

Q. DO THE INDICATED RISK PREMIUM RESULTS FROM THE IBBOTSON ASSOCIATES STUDY SUPPORT A RETURN ON COMMON EQUITY FOR PACIFICORP OF 10.9% AS ESTIMATED BY DR. HADAWAY?

A. No. There are several flaws in this analysis. First, the Ibbotson Associates study is based on common equity returns and equity risk premiums for the overall market. This study is based on the returns for the S&P 500, not electric utilities. Dr. Hadaway did not, and cannot, show that the S&P 500 companies reflect risk comparable to PacifiCorp as a regulated electric utility.

In fact, it is widely recognized that electric utility risk is considerably lower than that of the overall market. This is evident by a review of the beta coefficients measured by *Value Line* for utility companies, as illustrated in Exhibit ICNU-CUB/318, discussed above. As I noted earlier with respect to my CAPM analysis, utility company stock market risk is approximately 0.68 (beta estimate) of that of the overall market. Hence, while the equity risk premiums derived from this study may be appropriate for the overall market, they significantly overstate a reasonable equity risk premium for a low risk regulated electric utility, such as PacifiCorp. Therefore, Dr. Hadaway's use of the Ibbotson study's equity risk premium to produce a return on common equity for PacifiCorp is unreasonable and should be rejected.

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

A. Only generally. By recognizing that electric utilities like PacifiCorp have much lower risk than the overall market, the equity risk premiums developed by Ibbotson (4.5%) should be adjusted by a factor of approximately 68% or the median beta, as published by *The Value Line Investment Survey*. Using a 68% adjustment factor to reflect PacifiCorp's lower than market risk, the equity risk premiums of these studies, adjusted for the lower risk, would be reduced to 3.06% (4.5% x 68%). Adding a 3.06% equity risk premium to Dr. Hadaway's current cost of an "A" rated electric utility bond of 6.40% would indicate a return on common equity of 9.46%.

Q. CONSIDERING THE ADJUSTMENTS YOU MADE TO DR. HADAWAY'S ROE STUDY RESULTS, WHAT IS A REASONABLE RANGE OF A RETURN ON EQUITY FOR PACIFICORP?

A. A reasonable ROE range for PacifiCorp is 9.9% to 10.3%, based on my adjustments to Dr. Hadaway's DCF and risk premium studies. As discussed in detail above, when more detailed assessments of utilities' investment risk in today's marketplace are considered, and market models are used to estimate the current investor required return for electric utility companies today, this is a reasonable and accurate range of returns demanded by the marketplace for these companies. Thus, my recommended return on equity of 10.0% will fairly compensate PacifiCorp for its investment risk of providing regulated integrated utility service in Oregon.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
Request for a General Rate Revision.	)

ICNU-CUB/301

QUALIFICATIONS OF MICHAEL P. GORMAN

JULY 24, 2009

Qualifications of Michael P. Gorman

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. PLEASE STATE YOUR OCCUPATION.

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

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

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

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

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

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

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

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

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

Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Arkansas, Arizona, California, Colorado, Delaware, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Louisiana, Michigan, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Oklahoma, Oregon, South Carolina, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory Commissions in Alberta and Nova Scotia, Canada. I have also sponsored testimony before the Commission of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory Commission of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

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

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

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OF OREGON

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ICNU-CUB/302

RATE OF RETURN

JULY 24, 2009

PacifiCorp Oregon

Rate of Return

Line	Description	Weight (1)	Cost (2)	Weighted Cost (3)
1	Long-Term Debt	49.2%	5.98%	2.94%
2	Preferred Stock	0.3%	5.41%	0.02%
3	Common Equity*	50.5%	**10.00%**	5.05%
4	**Total**	**100.0%**		**8.01%**

Source:
Exhibit PPL/300 at 3.
* Adjusted to reflect additional retained earnings of $387 million based on 2009 return on equity of 6.5%.

PacifiCorp Oregon

Rate of Return
(Common Equity Balance)

Line	Description		Amount (1)	Reference (2)
1	Common Equity*	$	5,945,627,271	See Note.
2	Return on equity before the increase		6.517%	Exhibit PPL/701.
3	Increase in earnings	$	387,476,529	Line 1 x Line 2.
4	Common Equity	$	6,333,103,800	Line 1 + Line 3.
5	Equity Contribution**	$	200,000,000	See Note.
6	Adjusted Common Equity	$	6,533,103,800	Line 4 + Line 6.

Notes:
* PacifiCorp's Response to ICNU Data Requests 2.12.
** PacifiCorp's Response to ICNU Data Requests 2.11.

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PROXY GROUP

JULY 24, 2009

PacifiCorp Oregon

Proxy Group

Line	Company	Bond Ratings[1] S&P (1)	Bond Ratings[1] Moody's (2)	Common Equity Ratios *AUS*[1] (3)	Common Equity Ratios *Value Line*[2] (4)	S&P Business Profile Risk[3] (5)
1	ALLETE	A-	N/R	57.0%	58.4%	Strong
2	Alliant Energy	A-	A2	81.0%	58.6%	Excellent
3	Consol Edison	A-	A1	47.0%	51.2%	Excellent
4	DPL Inc.	A	A2	42.0%	42.4%	Excellent
5	DTE Energy	A-	A3	45.0%	43.6%	Excellent
6	Duke Energy	A	A3	58.0%	61.3%	Excellent
7	Edison Int'l	A	A2	44.0%	44.5%	Excellent
8	Entergy Corp	A-	Baa2	41.0%	40.2%	Strong
9	FPL Group	A	Aa3	41.0%	45.8%	Excellent
10	IDACORP, Inc	A-	A3	49.0%	52.4%	Strong
11	NSTAR	AA-	A1	38.0%	42.8%	Excellent
12	PG&E Corp	BBB+	A3	47.0%	46.5%	Excellent
13	Portland General	A	Baa1	52.0%	53.8%	Strong
14	Progress Energy	A-	A2	45.0%	44.4%	Excellent
15	Sempra Energy	A+	A1	52.0%	54.2%	N/A
16	Southern Co.	A	A2	39.0%	42.6%	Excellent
17	Vectren Corp.	A	A3	47.0%	52.0%	N/A
18	Wisconsin Energy	A-	Aa3	41.0%	44.8%	Excellent
19	Xcel Energy Inc.	A-	A3	45.0%	47.1%	Excellent
20	**Average**	**A**	**A2**	**47.9%**	**48.8%**	**Excellent**
21	PacifiCorp Oregon	A-[4]	A3[4]		50.5%[5]	Excellent

Sources:
[1] *AUS Utility Reports*, June 2009.
[2] *The Value Line Investment Survey,* March 27, May 8, and May 29, 2009.
[3] *S&P Ratings Direct:* "U.S. Regulated Electric Utilities, Strongest to Weakest," September 9, 2008.
[4] Exhibit PPL/200 at 3.
[5] ICNU-CUB/302, Gorman/1.

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ICNU-CUB/304

GROWTH RATES

JULY 24, 2009

PacifiCorp Oregon

Growth Rates

Line	Company	Zacks Estimated Growth %[1] (1)	Zacks Number of Estimates (2)	SNL Financial Estimated Growth %[2] (3)	SNL Financial Number of Estimates (4)	Thomson Financial Estimated Growth %[3] (5)	Thomson Financial Number of Estimates (6)	Average of Growth Rates (7)
1	ALLETE	4.00%	2	5.00%	3	6.00%	3	5.00%
2	Alliant Energy	5.30%	3	6.00%	2	5.95%	2	5.75%
3	Consol Edison	4.00%	3	2.50%	4	2.09%	4	2.86%
4	DPL Inc.	7.43%	3	8.30%	3	7.43%	3	7.72%
5	DTE Energy	6.00%	1	3.50%	2	3.50%	2	4.33%
6	Duke Energy	5.00%	4	4.00%	5	4.00%	5	4.33%
7	Edison Int'l	6.33%	3	4.10%	3	2.05%	3	4.16%
8	Entergy Corp	7.25%	4	8.00%	5	9.02%	5	8.09%
9	FPL Group	9.07%	6	10.00%	7	9.77%	7	9.61%
10	IDACORP, Inc	5.00%	2	5.00%	2	5.00%	2	5.00%
11	NSTAR	6.40%	5	6.00%	3	6.67%	3	6.36%
12	PG&E Corp	6.88%	4	6.80%	6	6.95%	6	6.88%
13	Portland General	6.67%	3	6.00%	6	7.14%	6	6.60%
14	Progress Energy	4.80%	5	5.00%	6	5.59%	6	5.13%
15	Sempra Energy	6.50%	2	7.00%	3	6.48%	3	6.66%
16	Southern Co.	5.00%	5	5.80%	5	5.36%	5	5.39%
17	Vectren Corp.	6.68%	4	6.00%	3	6.90%	3	6.53%
18	Wisconsin Energy	8.43%	6	9.00%	5	9.04%	5	8.82%
19	Xcel Energy Inc.	5.18%	5	6.00%	4	6.38%	4	5.85%
20	**Average**	**6.10%**	**4**	**6.00%**	**4**	**6.07%**	**4**	**6.06%**

Sources:
[1] Zacks Elite, http://www.zackselite.com/, downloaded on June 19, 2009.
[2] SNL Interactive, http://www.snl.com/, downloaded on June 19, 2009.
[3] Thomsons, http://tabsefin.swlearning.com/student/tabsefin_frame.html, downloaded on June 19, 2009.

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ICNU-CUB/305

CONSTANT GROWTH DCF MODEL

JULY 24, 2009

PacifiCorp Oregon

Constant Growth DCF Model

Line	Company	13-Week AVG Stock Price[1] (1)	Analysts' Growth[2] (2)	Annual Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE	$26.62	5.00%	$1.76	6.94%	11.94%
2	Alliant Energy	$24.08	5.75%	$1.50	6.59%	12.34%
3	Consol Edison	$37.12	2.86%	$2.36	6.54%	9.40%
4	DPL Inc.	$22.34	7.72%	$1.14	5.50%	13.22%
5	DTE Energy	$29.67	4.33%	$2.12	7.45%	11.79%
6	Duke Energy	$14.03	4.33%	$0.92	6.84%	11.17%
7	Edison Int'l	$29.21	4.16%	$1.24	4.42%	8.58%
8	Entergy Corp	$70.85	8.09%	$3.00	4.58%	12.67%
9	FPL Group	$53.92	9.61%	$1.89	3.85%	13.46%
10	IDACORP, Inc	$23.66	5.00%	$1.20	5.33%	10.33%
11	NSTAR	$30.82	6.36%	$1.50	5.18%	11.53%
12	PG&E Corp	$37.34	6.88%	$1.68	4.81%	11.69%
13	Portland General	$17.88	6.60%	$0.98	5.84%	12.45%
14	Progress Energy	$35.36	5.13%	$2.48	7.37%	12.50%
15	Sempra Energy	$45.95	6.66%	$1.56	3.62%	10.28%
16	Southern Co.	$29.60	5.39%	$1.75	6.24%	11.62%
17	Vectren Corp.	$21.84	6.53%	$1.34	6.54%	13.06%
18	Wisconsin Energy	$39.76	8.82%	$1.35	3.70%	12.52%
19	Xcel Energy Inc.	$18.01	5.85%	$0.95	5.59%	11.45%
20	**Average**	**$32.00**	**6.06%**	**$1.62**	**5.63%**	**11.68%**

Sources:
[1] http://moneycentral.msn.com, downloaded on June 22, 2009.
[2] ICNU-CUB/304, Column 7.
[3] *The Value Line Investment Survey,* March 27, May 8, and May 29, 2009.

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ICNU-CUB/306

DIVIDEND YIELDS

JULY 24, 2009

PacifiCorp Oregon

Dividend Yields

Line	Company	13-Week AVG Stock Price[1] (1)	Annual Dividend[2] (2)	Dividend Yield[2] 2004 (3)	2005 (4)	2006 (5)	2007 (6)	2008 (7)	2009 (8)	'04 - '08 Average Dividend Yield (9)
1	ALLETE	$26.62	$1.76	0.90%	2.80%	3.20%	3.60%	4.40%	6.61%	2.98%
2	Alliant Energy	$24.08	$1.50	3.90%	3.80%	3.30%	3.10%	4.10%	6.23%	3.64%
3	Consol Edison	$37.12	$2.36	5.30%	5.00%	5.00%	4.80%	5.70%	6.36%	5.16%
4	DPL Inc.	$22.34	$1.14	4.70%	3.70%	3.70%	3.60%	4.30%	5.10%	4.00%
5	DTE Energy	$29.67	$2.12	5.00%	4.60%	4.90%	4.40%	5.20%	7.14%	4.82%
6	Duke Energy	$14.03	$0.92	N/A	N/A	N/A	4.40%	5.20%	6.56%	4.80%
7	Edison Int'l	$29.21	$1.24	3.10%	2.60%	2.60%	2.20%	2.70%	4.24%	2.64%
8	Entergy Corp	$70.85	$3.00	3.20%	3.00%	2.80%	2.40%	2.90%	4.23%	2.86%
9	FPL Group	$53.92	$1.89	3.90%	3.40%	3.40%	2.70%	3.00%	3.51%	3.28%
10	IDACORP, Inc	$23.66	$1.20	4.10%	4.10%	3.40%	3.50%	4.00%	5.07%	3.82%
11	NSTAR	$30.82	$1.50	4.60%	3.10%	5.00%	3.90%	4.30%	4.87%	4.18%
12	PG&E Corp	$37.34	$1.68	N/A	3.40%	3.20%	3.10%	4.00%	4.50%	3.43%
13	Portland General	$17.88	$0.98	N/A	N/A	2.50%	3.30%	4.30%	5.48%	3.37%
14	Progress Energy	$35.36	$2.48	5.30%	5.50%	5.50%	5.10%	5.80%	7.01%	5.44%
15	Sempra Energy	$45.95	$1.56	2.90%	2.80%	2.50%	2.10%	2.60%	3.39%	2.58%
16	Southern Co.	$29.60	$1.75	4.70%	4.40%	4.50%	4.40%	4.60%	5.92%	4.52%
17	Vectren Corp.	$21.84	$1.34	4.60%	4.40%	4.50%	4.50%	4.70%	6.14%	4.54%
18	Wisconsin Energy	$39.76	$1.35	2.60%	2.40%	2.20%	2.10%	2.40%	3.40%	2.34%
19	Xcel Energy Inc.	$18.01	$0.95	4.70%	4.60%	4.40%	4.00%	4.70%	5.29%	4.48%
20	**Average**	**$32.00**	**$1.62**	**3.97%**	**3.74%**	**3.70%**	**3.54%**	**4.15%**	**5.32%**	**3.84%**

Sources:
[1] http://moneycentral.msn.com, downloaded on June 22, 2009.
[2] *The Value Line Investment Survey,* March 27, May 8, and May 29, 2009.

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HISTORICAL GROWTH RATES

JULY 24, 2009

PacifiCorp Oregon

Historical Growth Rates

		Dividend Growth			Inflation (CPI)			Nominal GDP			
		Historical		3-5 Years	Historical		3-5 Years	Historical		Projected*	
Line	Company	10 Years	5 Years	Projection	5 Years	10 Years	Projection	5 Years	10 Years	5 Years	10 Years
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ALLETE	N/A	N/A	3.0%							
2	Alliant Energy	-5.0%	-10.5%	7.0%							
3	Consol Edison	1.0%	1.0%	1.0%							
4	DPL Inc.	1.5%	1.0%	3.5%							
5	DTE Energy	N/A	N/A	2.5%							
6	Duke Energy	N/A	N/A	N/A							
7	Edison Int'l	1.5%	N/A	4.5%							
8	Entergy Corp	4.5%	13.0%	4.5%							
9	FPL Group	5.5%	7.0%	6.0%							
10	IDACORP, Inc	-4.5%	-8.0%	N/A							
11	NSTAR	4.0%	6.0%	5.5%							
12	PG&E Corp	0.5%	N/A	7.5%							
13	Portland General	N/A	N/A	7.0%							
14	Progress Energy	2.5%	2.0%	1.0%							
15	Sempra Energy	-2.0%	5.0%	8.5%							
16	Southern Co.	2.0%	3.0%	4.0%							
17	Vectren Corp.	N/A	3.5%	3.0%							
18	Wisconsin Energy	-4.0%	4.5%	12.0%							
19	Xcel Energy Inc.	-4.0%	-4.0%	3.0%							
20	**Average**	**0.3%**	**1.8%**	**4.9%**	**3.2%**	**2.8%**	**2.8%**	**5.4%**	**5.0%**	**5.2%**	**4.9%**

Sources:
The Value Line Investment Survey, March 27, May 8, and May 29, 2009.
* *Blue Chip Economic Indicators,* March 10, 2009, at 15.

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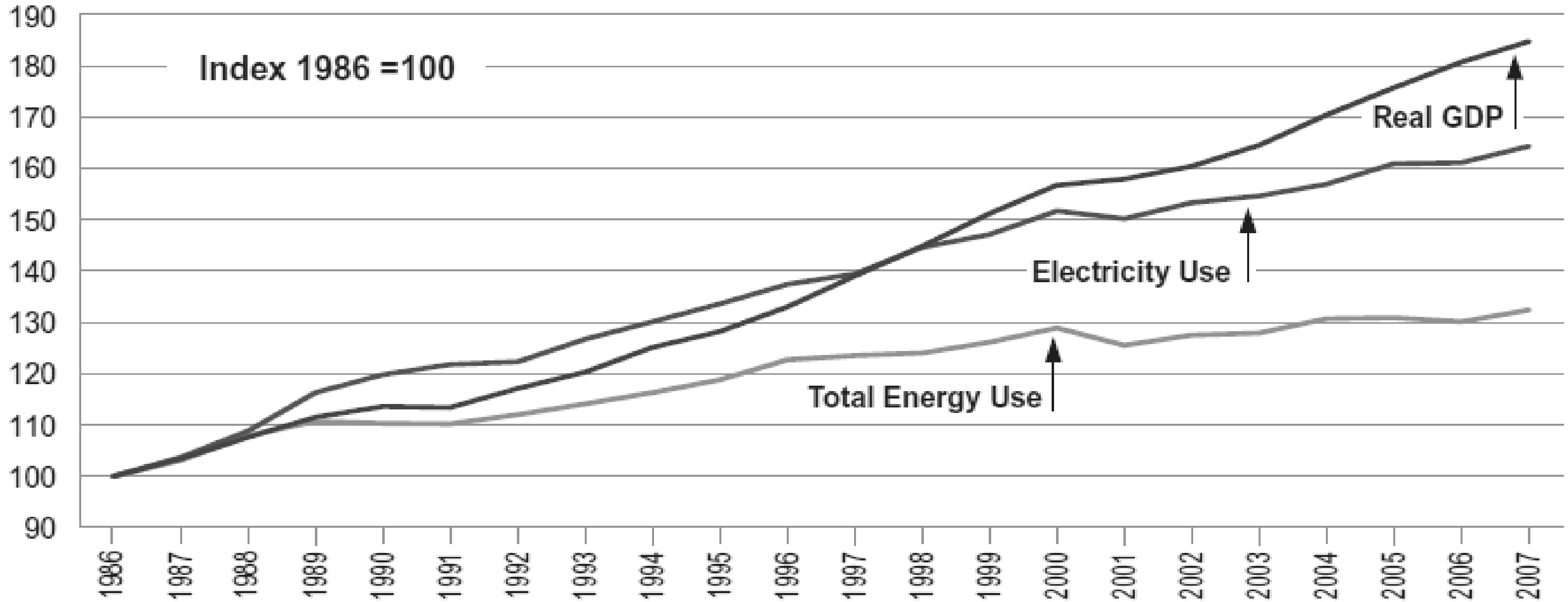
ELECTRICITY SALES ARE LINKED TO U.S. ECONOMIC GROWTH

JULY 24, 2009

PacifiCorp Oregon

Electricity Sales Are Linked to U.S. Economic Growth



1986 represents the base year. Graph depicts increases or decreases from the base year.

Source: U.S. Department of Energy, Energy Information Administration (EIA).

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CURRENT AND PROJECTED PAYOUT RATIOS

JULY 24, 2009

PacifiCorp Oregon

Current and Projected Payout Ratios

		Dividends Per Share		Earnings Per Share		Payout Ratio	
Line	**Company**	**2008**	**3-5 Years**	**2008**	**3-5 Years**	**2008**	**3-5 Years**
		(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**
1	ALLETE	$1.72	$1.92	$2.82	$2.75	60.99%	69.82%
2	Alliant Energy	$1.40	$1.92	$2.54	$3.25	55.12%	59.08%
3	Consol Edison	$2.34	$2.44	$3.36	$3.80	69.64%	64.21%
4	DPL Inc.	$1.10	$1.30	$2.12	$2.60	51.89%	50.00%
5	DTE Energy	$2.12	$2.50	$2.73	$3.75	77.66%	66.67%
6	Duke Energy	$0.90	$1.10	$1.01	$1.40	89.11%	78.57%
7	Edison Int'l	$1.23	$1.50	$3.68	$4.25	33.42%	35.29%
8	Entergy Corp	$3.00	$3.40	$6.20	$8.00	48.39%	42.50%
9	FPL Group	$1.78	$2.30	$4.07	$5.75	43.73%	40.00%
10	IDACORP, Inc	$1.20	$1.20	$2.18	$2.75	55.05%	43.64%
11	NSTAR	$1.43	$1.95	$2.22	$3.25	64.41%	60.00%
12	PG&E Corp	$1.56	$2.20	$3.22	$4.25	48.45%	51.76%
13	Portland General	$0.97	$1.30	$1.39	$2.25	69.78%	57.78%
14	Progress Energy	$2.46	$2.56	$2.96	$3.60	83.11%	71.11%
15	Sempra Energy	$1.37	$2.10	$4.43	$5.75	30.93%	36.52%
16	Southern Co.	$1.66	$2.00	$2.25	$3.00	73.78%	66.67%
17	Vectren Corp.	$1.31	$1.51	$1.65	$2.35	79.39%	64.26%
18	Wisconsin Energy	$1.08	$2.05	$3.03	$4.50	35.64%	45.56%
19	Xcel Energy Inc.	$0.94	$1.10	$1.46	$2.00	64.38%	55.00%
20	**Average**	**$1.56**	**$1.91**	**$2.81**	**$3.64**	**59.73%**	**55.71%**

Source:
The Value Line Investment Survey, March 27, May 8, and May 29, 2009.

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SUSTAINABLE GROWTH RATE

JULY 24, 2009

PacifiCorp Oregon

Sustainable Growth Rate

		3 to 5 Year Projections						
		Dividends	Earnings	Book Value		Payout	Retention	Internal
Line	**Company**	**Per Share**	**Per Share**	**Per Share**	**ROE**	**Ratio**	**Rate**	**Growth Rate**
		(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**
1	ALLETE	$1.92	$2.75	$29.25	9.40%	69.82%	30.18%	2.84%
2	Alliant Energy	$1.92	$3.25	$31.05	10.47%	59.08%	40.92%	4.28%
3	Consol Edison	$2.44	$3.80	$41.60	9.13%	64.21%	35.79%	3.27%
4	DPL Inc.	$1.30	$2.60	$13.90	18.71%	50.00%	50.00%	9.35%
5	DTE Energy	$2.50	$3.75	$42.00	8.93%	66.67%	33.33%	2.98%
6	Duke Energy	$1.10	$1.40	$17.75	7.89%	78.57%	21.43%	1.69%
7	Edison Int'l	$1.50	$4.25	$39.00	10.90%	35.29%	64.71%	7.05%
8	Entergy Corp	$3.40	$8.00	$63.75	12.55%	42.50%	57.50%	7.22%
9	FPL Group	$2.30	$5.75	$43.25	13.29%	40.00%	60.00%	7.98%
10	IDACORP, Inc	$1.20	$2.75	$35.60	7.72%	43.64%	56.36%	4.35%
11	NSTAR	$1.95	$3.25	$22.00	14.77%	60.00%	40.00%	5.91%
12	PG&E Corp	$2.20	$4.25	$35.75	11.89%	51.76%	48.24%	5.73%
13	Portland General	$1.30	$2.25	$25.00	9.00%	57.78%	42.22%	3.80%
14	Progress Energy	$2.56	$3.60	$36.80	9.78%	71.11%	28.89%	2.83%
15	Sempra Energy	$2.10	$5.75	$49.75	11.56%	36.52%	63.48%	7.34%
16	Southern Co.	$2.00	$3.00	$22.25	13.48%	66.67%	33.33%	4.49%
17	Vectren Corp.	$1.51	$2.35	$22.80	10.31%	64.26%	35.74%	3.68%
18	Wisconsin Energy	$2.05	$4.50	$38.00	11.84%	45.56%	54.44%	6.45%
19	Xcel Energy Inc.	$1.10	$2.00	$19.00	10.53%	55.00%	45.00%	4.74%
20	**Average**	**$1.91**	**$3.64**	**$33.08**	**11.17%**	**55.71%**	**44.29%**	**5.05%**

Sources:
The Value Line Investment Survey, March 27, May 8, and May 29, 2009.

BEFORE THE PUBLIC UTILITY COMMISSION

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ICNU-CUB/311

SUSTAINABLE CONSTANT GROWTH DCF MODEL

JULY 24, 2009

PacifiCorp Oregon

Sustainable Constant Growth DCF Model

Line	Company	13-Week AVG Stock Price[1] (1)	Sustainable Growth[2] (2)	Annual Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE	$26.62	2.84%	$1.76	6.80%	9.64%
2	Alliant Energy	$24.08	4.28%	$1.50	6.49%	10.78%
3	Consol Edison	$37.12	3.27%	$2.36	6.57%	9.84%
4	DPL Inc.	$22.34	9.35%	$1.14	5.58%	14.93%
5	DTE Energy	$29.67	2.98%	$2.12	7.36%	10.33%
6	Duke Energy	$14.03	1.69%	$0.92	6.67%	8.36%
7	Edison Int'l	$29.21	7.05%	$1.24	4.54%	11.60%
8	Entergy Corp	$70.85	7.22%	$3.00	4.54%	11.76%
9	FPL Group	$53.92	7.98%	$1.89	3.79%	11.77%
10	IDACORP, Inc	$23.66	4.35%	$1.20	5.29%	9.65%
11	NSTAR	$30.82	5.91%	$1.50	5.16%	11.06%
12	PG&E Corp	$37.34	5.73%	$1.68	4.76%	10.49%
13	Portland General	$17.88	3.80%	$0.98	5.69%	9.49%
14	Progress Energy	$35.36	2.83%	$2.48	7.21%	10.04%
15	Sempra Energy	$45.95	7.34%	$1.56	3.64%	10.98%
16	Southern Co.	$29.60	4.49%	$1.75	6.19%	10.68%
17	Vectren Corp.	$21.84	3.68%	$1.34	6.36%	10.05%
18	Wisconsin Energy	$39.76	6.45%	$1.35	3.62%	10.07%
19	Xcel Energy Inc.	$18.01	4.74%	$0.95	5.54%	10.27%
20	**Average**	**$32.00**	**5.05%**	**$1.62**	**5.57%**	**10.62%**

Sources:
[1] http://moneycentral.msn.com, downloaded on June 22, 2009.
[2] ICNU-CUB/310, Column 7.
[3] *The Value Line Investment Survey,* March 27, May 8, and May 29, 2009.

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MULTI-STAGE GROWTH DCF MODEL

JULY 24, 2009

PacifiCorp Oregon

Multi-Stage Growth DCF Model

Line	Company	13-Week AVG Stock Price[1]	Annual Dividend[2]	First Stage Growth	Second Stage Growth Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth[3]	Multi-Stage Growth DCF
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	ALLETE	$26.62	$1.76	5.00%	5.02%	5.03%	5.05%	5.07%	5.08%	5.10%	12.01%
2	Alliant Energy	$24.08	$1.50	5.75%	5.64%	5.53%	5.43%	5.32%	5.21%	5.10%	11.90%
3	Consol Edison	$37.12	$2.36	2.86%	3.24%	3.61%	3.98%	4.35%	4.73%	5.10%	10.95%
4	DPL Inc.	$22.34	$1.14	7.72%	7.28%	6.85%	6.41%	5.97%	5.54%	5.10%	11.36%
5	DTE Energy	$29.67	$2.12	4.33%	4.46%	4.59%	4.72%	4.84%	4.97%	5.10%	12.29%
6	Duke Energy	$14.03	$0.92	4.33%	4.46%	4.59%	4.72%	4.84%	4.97%	5.10%	11.69%
7	Edison Int'l	$29.21	$1.24	4.16%	4.32%	4.47%	4.63%	4.79%	4.94%	5.10%	9.30%
8	Entergy Corp	$70.85	$3.00	8.09%	7.59%	7.09%	6.60%	6.10%	5.60%	5.10%	10.43%
9	FPL Group	$53.92	$1.89	9.61%	8.86%	8.11%	7.36%	6.60%	5.85%	5.10%	9.96%
10	IDACORP, Inc	$23.66	$1.20	5.00%	5.02%	5.03%	5.05%	5.07%	5.08%	5.10%	10.40%
11	NSTAR	$30.82	$1.50	6.36%	6.15%	5.94%	5.73%	5.52%	5.31%	5.10%	10.62%
12	PG&E Corp	$37.34	$1.68	6.88%	6.58%	6.29%	5.99%	5.69%	5.40%	5.10%	10.37%
13	Portland General	$17.88	$0.98	6.60%	6.35%	6.10%	5.85%	5.60%	5.35%	5.10%	11.39%
14	Progress Energy	$35.36	$2.48	5.13%	5.12%	5.12%	5.11%	5.11%	5.10%	5.10%	12.48%
15	Sempra Energy	$45.95	$1.56	6.66%	6.40%	6.14%	5.88%	5.62%	5.36%	5.10%	9.03%
16	Southern Co.	$29.60	$1.75	5.39%	5.34%	5.29%	5.24%	5.20%	5.15%	5.10%	11.43%
17	Vectren Corp.	$21.84	$1.34	6.53%	6.29%	6.05%	5.81%	5.58%	5.34%	5.10%	12.10%
18	Wisconsin Energy	$39.76	$1.35	8.82%	8.20%	7.58%	6.96%	6.34%	5.72%	5.10%	9.60%
19	Xcel Energy Inc.	$18.01	$0.95	5.85%	5.73%	5.60%	5.48%	5.35%	5.23%	5.10%	10.91%
20	**Average**	**$32.00**	**$1.62**	**6.06%**	**5.90%**	**5.74%**	**5.58%**	**5.42%**	**5.26%**	**5.10%**	**10.96%**

Sources:
[1] http://moneycentral.msn.com, downloaded on June 22, 2009.
[2] *The Value Line Investment Survey,* March 27, May 8, and May 29, 2009.
[3] *Blue Chip Economic Indicators*, March 10, 2009.

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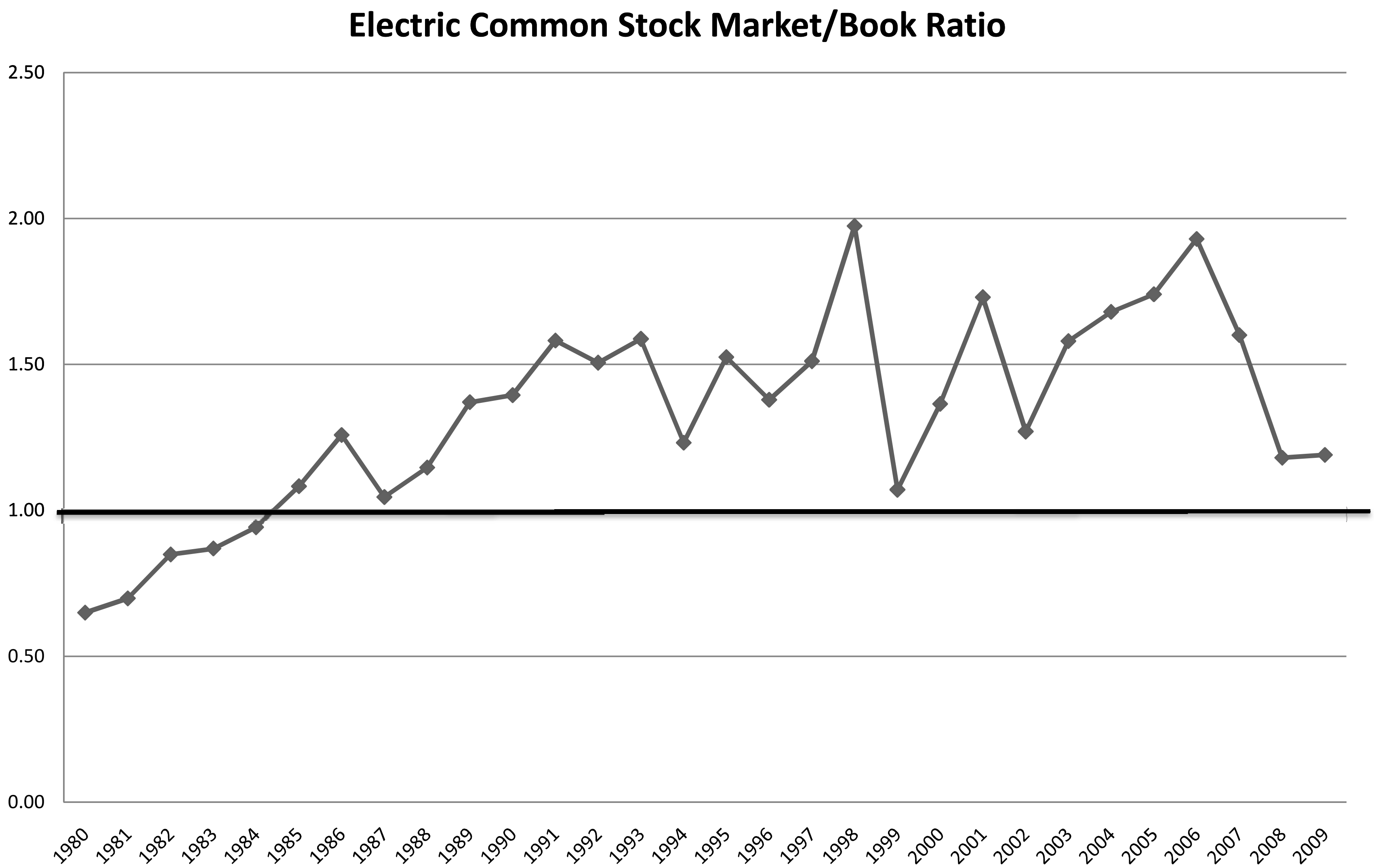
ELECTRIC COMMON STOCK MARKET/BOOK RATIO

JULY 24, 2009

PacifiCorp Oregon



Sources:
2001 - March 2009: *AUS Utility Reports.*
1980 - 2000: *Mergent Public Utility Manual* ; at a15, and a17.

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EQUITY RISK PREMIUM – TREASURY BOND

JULY 24, 2009

PacifiCorp Oregon

Equity Risk Premium - Treasury Bond

Line	Date	Authorized Electric Returns[1] (1)	Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)
1	1986	13.93%	7.78%	6.15%
2	1987	12.99%	8.59%	4.40%
3	1988	12.79%	8.96%	3.83%
4	1989	12.97%	8.45%	4.52%
5	1990	12.70%	8.61%	4.09%
6	1991	12.55%	8.14%	4.41%
7	1992	12.09%	7.67%	4.42%
8	1993	11.41%	6.59%	4.82%
9	1994	11.34%	7.37%	3.97%
10	1995	11.55%	6.88%	4.67%
11	1996	11.39%	6.71%	4.68%
12	1997	11.40%	6.61%	4.79%
13	1998	11.66%	5.58%	6.08%
14	1999	10.77%	5.87%	4.90%
15	2000	11.43%	5.94%	5.49%
16	2001	11.09%	5.49%	5.60%
17	2002	11.16%	5.43%	5.73%
18	2003	10.97%	4.96%	6.01%
19	2004	10.75%	5.05%	5.70%
20	2005	10.54%	4.65%	5.89%
21	2006	10.36%	4.91%	5.45%
22	2007	10.36%	4.84%	5.52%
23	2008	10.46%	4.28%	6.18%
24	Q1 2009[3]	10.31%	3.45%	6.86%
25	**Average**	**11.54%**	**6.37%**	**5.17%**

Sources:
[1] Regulatory Research Associates, Inc., *Regulatory Focus,* Jan. 85 - Dec. 06, and January 12, 2009.
[2] Economic Report of the President 2008: Table 73. The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.
[3] EEI, Rate Case Summary 1Q 2009 Financial Update.

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EQUITY RISK PREMIUM – UTILITY BOND

JULY 24, 2009

PacifiCorp Oregon

Equity Risk Premium - Utility Bond

Line	Date	Authorized Electric Returns[1] (1)	Average "A" Rating Utility Bond Yield[2] (2)	Indicated Risk Premium (3)
1	1986	13.93%	9.58%	4.35%
2	1987	12.99%	10.10%	2.89%
3	1988	12.79%	10.49%	2.30%
4	1989	12.97%	9.77%	3.20%
5	1990	12.70%	9.86%	2.84%
6	1991	12.55%	9.36%	3.19%
7	1992	12.09%	8.69%	3.40%
8	1993	11.41%	7.59%	3.82%
9	1994	11.34%	8.31%	3.03%
10	1995	11.55%	7.89%	3.66%
11	1996	11.39%	7.75%	3.64%
12	1997	11.40%	7.60%	3.80%
13	1998	11.66%	7.04%	4.62%
14	1999	10.77%	7.62%	3.15%
15	2000	11.43%	8.24%	3.19%
16	2001	11.09%	7.76%	3.33%
17	2002	11.16%	7.37%	3.79%
18	2003	10.97%	6.58%	4.39%
19	2004	10.75%	6.16%	4.59%
20	2005	10.54%	5.65%	4.89%
21	2006	10.36%	6.07%	4.29%
22	2007	10.36%	6.07%	4.29%
23	2008	10.46%	6.53%	3.93%
24	Q1 2009[3]	10.31%	6.37%	3.94%
25	**Average**	**11.54%**	**7.85%**	**3.69%**

Sources:
[1] Regulatory Research Associates, Inc., *Regulatory Focus,* Jan. 85 - Dec. 06, and January 12, 2009.
[2] Economic Report of the President 2008: Table 73. The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.
[3] EEI, Rate Case Summary 1Q 2009 Financial Update.

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ICNU-CUB/316

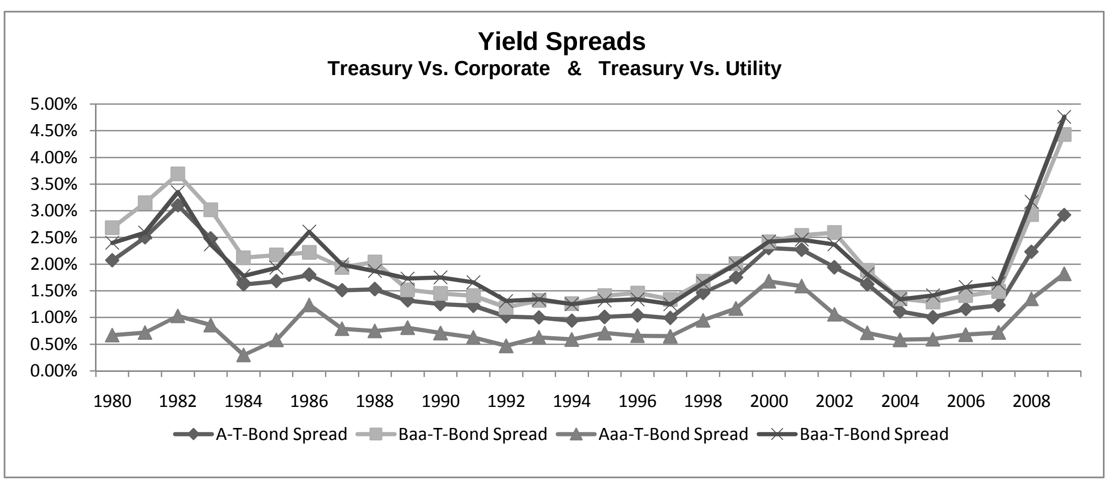
BOND YIELD SPREADS

JULY 24, 2009

PacifiCorp Oregon

Bond Yield Spreads

			Public Utility Bond Yields				Corporate Bond Yields				
Line	Year	T-Bond Yield[1] (1)	A[2] (2)	Baa[2] (3)	A-T-Bond Spread (4)	Baa-T-Bond Spread (5)	Aaa[1] (6)	Baa[1] (7)	Aaa-T-Bond Spread (8)	Baa-T-Bond Spread (9)	Baa Utility - Corporate (10)
1	1980	11.27%	13.34%	13.95%	2.07%	2.68%	11.94%	13.67%	0.67%	2.40%	0.28%
2	1981	13.45%	15.95%	16.60%	2.50%	3.15%	14.17%	16.04%	0.72%	2.59%	0.56%
3	1982	12.76%	15.86%	16.45%	3.10%	3.69%	13.79%	16.11%	1.03%	3.35%	0.34%
4	1983	11.18%	13.66%	14.20%	2.48%	3.02%	12.04%	13.55%	0.86%	2.37%	0.65%
5	1984	12.41%	14.03%	14.53%	1.62%	2.12%	12.71%	14.19%	0.30%	1.78%	0.34%
6	1985	10.79%	12.47%	12.96%	1.68%	2.17%	11.37%	12.72%	0.58%	1.93%	0.24%
7	1986	7.78%	9.58%	10.00%	1.80%	2.22%	9.02%	10.39%	1.24%	2.61%	-0.39%
8	1987	8.59%	10.10%	10.53%	1.51%	1.94%	9.38%	10.58%	0.79%	1.99%	-0.05%
9	1988	8.96%	10.49%	11.00%	1.53%	2.04%	9.71%	10.83%	0.75%	1.87%	0.17%
10	1989	8.45%	9.77%	9.97%	1.32%	1.52%	9.26%	10.18%	0.81%	1.73%	-0.21%
11	1990	8.61%	9.86%	10.06%	1.25%	1.45%	9.32%	10.36%	0.71%	1.75%	-0.30%
12	1991	8.14%	9.36%	9.55%	1.22%	1.41%	8.77%	9.80%	0.63%	1.66%	-0.25%
13	1992	7.67%	8.69%	8.86%	1.02%	1.19%	8.14%	8.98%	0.47%	1.31%	-0.12%
14	1993	6.59%	7.59%	7.91%	1.00%	1.32%	7.22%	7.93%	0.63%	1.34%	-0.02%
15	1994	7.37%	8.31%	8.63%	0.94%	1.26%	7.96%	8.62%	0.59%	1.25%	0.01%
16	1995	6.88%	7.89%	8.29%	1.01%	1.41%	7.59%	8.20%	0.71%	1.32%	0.09%
17	1996	6.71%	7.75%	8.17%	1.04%	1.46%	7.37%	8.05%	0.66%	1.34%	0.12%
18	1997	6.61%	7.60%	7.95%	0.99%	1.34%	7.26%	7.86%	0.65%	1.25%	0.09%
19	1998	5.58%	7.04%	7.26%	1.46%	1.68%	6.53%	7.22%	0.95%	1.64%	0.04%
20	1999	5.87%	7.62%	7.88%	1.75%	2.01%	7.04%	7.87%	1.17%	2.00%	0.01%
21	2000	5.94%	8.24%	8.36%	2.30%	2.42%	7.62%	8.36%	1.68%	2.42%	0.00%
22	2001	5.49%	7.76%	8.03%	2.27%	2.54%	7.08%	7.95%	1.59%	2.46%	0.08%
23	2002	5.43%	7.37%	8.02%	1.94%	2.59%	6.49%	7.80%	1.06%	2.37%	0.22%
24	2003	4.96%	6.58%	6.84%	1.62%	1.88%	5.67%	6.77%	0.71%	1.81%	0.07%
25	2004	5.05%	6.16%	6.40%	1.11%	1.35%	5.63%	6.39%	0.58%	1.34%	0.01%
26	2005	4.65%	5.65%	5.93%	1.00%	1.29%	5.24%	6.06%	0.59%	1.41%	-0.13%
27	2006	4.91%	6.07%	6.32%	1.16%	1.41%	5.59%	6.48%	0.68%	1.57%	-0.16%
28	2007	4.84%	6.07%	6.33%	1.23%	1.49%	5.56%	6.48%	0.72%	1.64%	-0.15%
29	2008	4.28%	6.51%	7.21%	2.23%	2.93%	5.63%	7.45%	1.35%	3.17%	-0.24%
30	Q1 2009	3.45%	6.37%	7.88%	2.92%	4.43%	5.27%	8.21%	1.82%	4.76%	-0.33%
31	**Average**	**7.49%**	**9.12%**	**9.54%**	**1.64%**	**2.05%**	**8.35%**	**9.50%**	**0.86%**	**2.01%**	**0.03%**



Sources:
[1] Economic Report of the President 2008: Table 73 at 316. The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.
[2] *Mergent Public Utility Manual* 2003. Moody's Daily News Reports.

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UTILITY BOND YIELDS

JULY 24, 2009

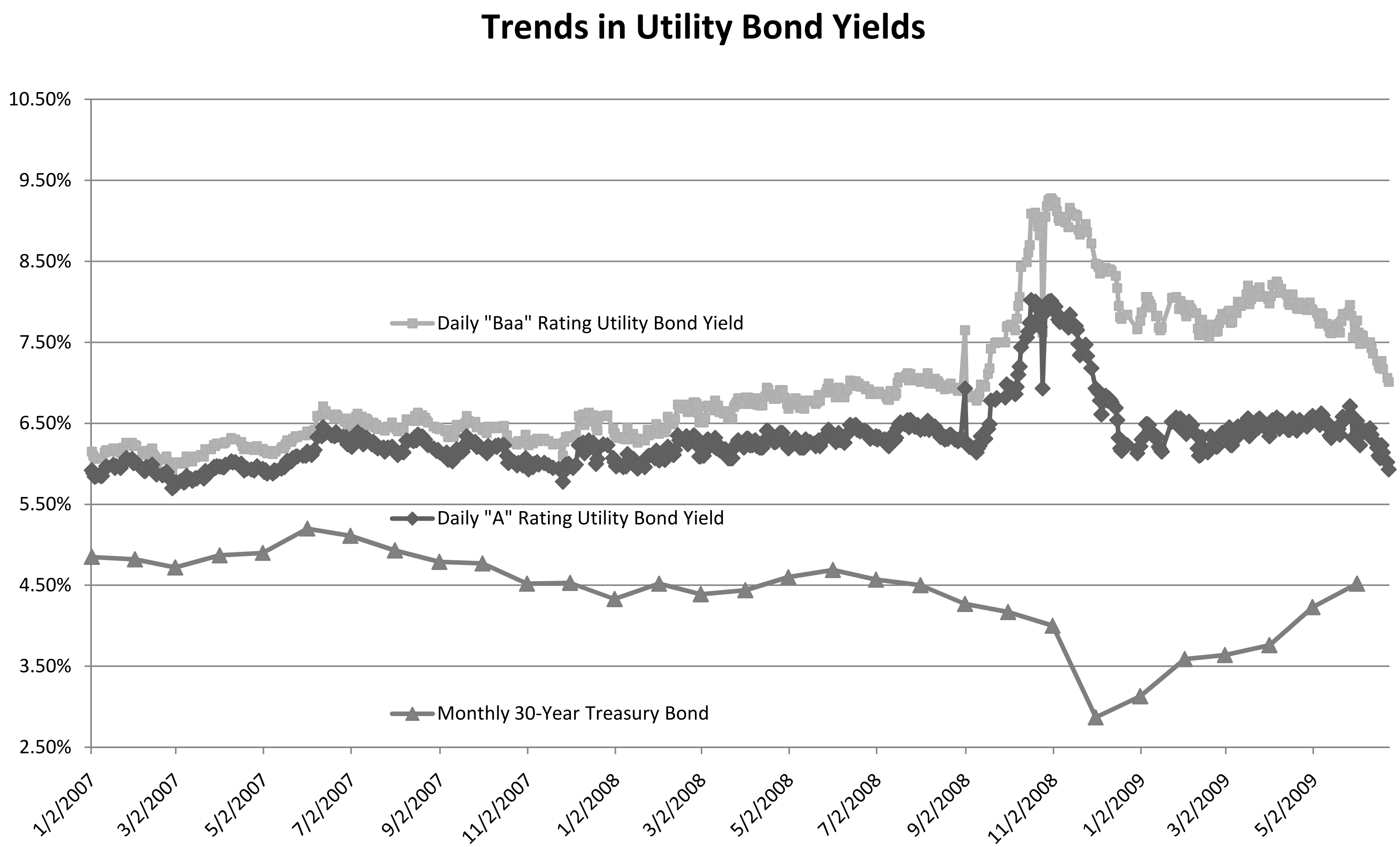
PacifiCorp Oregon

Utility Bond Yields

Line	Date	"A" Rating Utility Bond Yield (1)	"Baa" Rating Utility Bond Yield (2)
1	03/25/09	6.56%	8.18%
2	04/03/09	6.54%	8.21%
3	04/09/09	6.53%	8.16%
4	04/17/09	6.56%	8.09%
5	04/24/09	6.50%	7.94%
6	05/01/09	6.59%	7.90%
7	05/08/09	6.60%	7.83%
8	05/15/09	6.34%	7.63%
9	05/22/09	6.58%	7.85%
10	05/29/09	6.32%	7.56%
11	06/05/09	6.41%	7.58%
12	06/12/09	6.30%	7.36%
13	06/19/09	6.14%	7.17%
14	**Average**	**6.46%**	**7.80%**

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

PacifiCorp Oregon



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BETA

JULY 24, 2009

PacifiCorp Oregon

Beta

Line	Company	Beta
1	ALLETE	0.65
2	Alliant Energy	0.65
3	Consol Edison	0.65
4	DPL Inc.	0.60
5	DTE Energy	0.65
6	Duke Energy	0.65
7	Edison Int'l	0.80
8	Entergy Corp	0.70
9	FPL Group	0.75
10	IDACORP, Inc	0.70
11	NSTAR	0.65
12	PG&E Corp	0.60
13	Portland General	0.70
14	Progress Energy	0.65
15	Sempra Energy	0.90
16	Southern Co.	0.55
17	Vectren Corp.	0.75
18	Wisconsin Energy	0.65
19	Xcel Energy Inc.	0.65
20	**Average**	**0.68**

Source:
The Value Line Investment Survey,
March 27, May 8, and May 29, 2009.

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CAPM

JULY 24, 2009

PacifiCorp Oregon

CAPM

Line	Description	Historical Premium
1	Risk-Free Rate[1]	4.60%
2	Risk Premium[2]	5.60%
3	Beta[3]	0.68
4	CAPM	8.41%

Line	Description	Prospective Premium
5	Risk-Free Rate[1]	4.60%
6	Risk Premium[1/2]	6.07%
7	Beta[3]	0.68
8	CAPM	8.73%
9	**CAPM Average**	**8.57%**

Sources:

[1] *Blue Chip Financial Forecasts*; June 1, 2009 at 2.

[2] Morningstar, Inc. *Ibbotson SBBI 2009 Classic Yearbook,* at 100.

[3] *The Value Line Investment Survey,* March 27, May 8, and May 29, 2009.

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S&P CREDIT METRIC FINANCIAL RATIOS

JULY 24, 2009

PacifiCorp Oregon

S&P Credit Metric Financial Ratios
(ROE at 10.00%)

Line	Description	Amount (1)	Old S&P Benchmark[1] "A" Rating (2)	Old S&P Benchmark[1] "BBB" Rating (3)	New S&P Benchmark[2] (4)	Reference (5)
1	Rate Base	$ 2,958,306,726				Dalley Direct, Exhibit PPL/701, Page 1.
2	Weighted Common Return	5.05%				ICNU-CUB/302, Line 3, Col. 3.
3	Income to Common	$ 149,278,282				Line1 x Line 2.
4	Depreciation & Amortization	$ 164,521,840				Dalley Direct, Exhibit PPL/701, Page 1.
5	Imputed Amortization	$ 8,657,222				Page 3 , Line 15.
6	Deferred Income Taxes	$ 17,791,779				Dalley Direct, Exhibit PPL/701, Page 1.
7	Funds from Operations (FFO)	$ 340,249,122				Sum of Line 3 through Line 6.
8	Weighted Interest Rate	2.94%				ICNU-CUB/302, Line 1, Col. 3.
9	Interest Expense	$ 87,071,775				Line 1 x Line 8.
10	Imputed Interest Expense	$ 7,999,711				Page 3, Line 14.
11	FFO Plus Interest	$ 435,320,608				Line 7 + Line 9 + Line 10.
12	FFO Interest Coverage	4.6x	**3.8x - 4.5x**	2.8x - 3.8x	2.0x - 3.5x	Line 11/ (Line 9 + Line 10).
13	Total Debt Ratio	50%	**42% - 50%**	**50% - 60%**	45% - 60%	Page 2, Line 3.
14	FFO to Total Debt	23%	**22% - 30%**	15% - 22%	10% - 30%	Line 7 / (Line 1 x Line 13).

Sources:
[1] Standard & Poor's, "New Business Profile Scores Assigned to U.S. Utility and Power Companies; Financial Guidelines Revised," June 2, 2004; and "U.S. Integrated Electric Utility Companies, Strongest to Weakest," November 1, 2007.
[2] Standard & Poor's, "U.S. Utilities Ratings Analysis Now Portrayed in The S&P Corporate Ratings Matrix," November 30, 2007; and "U.S. Integrated Electric Utility Companies, Strongest to Weakest," September 9, 2009.

Note:
Based on the old S&P metrics, PacifiCorp's Business Profile Score was '5'.
Based on the new S&P metrics PacifiCorp has an "Excellent" business profile and an "Aggressive" financial profile.

PacifiCorp Oregon

S&P Credit Metric Financial Ratios

Financial Capital Structure

Line	Description	Weight
1	Long-Term Debt	48.75%
2	Off-Balance Sheet Debt	0.96%
3	**Total Long-Term Debt**	**49.71%**
4	Preferred Stock	0.32%
5	Common Equity*	49.98%
6	**Total**	**100.00%**

Source:
ICNU-CUB/302.

PacifiCorp Oregon

S&P Credit Metric Financial Ratios
Off-Balance Sheet Debt Equivalents

Line	Description	Amount (1)	Reference (2)
	PacifiCorp Oregon Allocator [1]		
1	Oregon June 2008 Rate Base	$ 2,604,159,502	
2	Total Company June 2008 Rate Base	$ 9,505,525,274	
3	PacifiCorp Oregon Allocator	**27.40%**	Line 1 / Line 2.
	Total Company [2]		
	Off-Balance Sheet Debt		
4	Operating Leases	$ 35,100,000	
5	Purchased Power Agreements	$ 424,000,000	
6	**Total Off-Balance Sheet Debt**	**$ 459,100,000**	
	Imputed Interest Expense		
7	Operating Leases	$ 2,300,000	
8	Purchased Power Agreements	$ 26,900,000	
9	**Total Imputed Interest Expense**	**$ 29,200,000**	
	Imputed Amortization Expense		
10	Operating Leases	$ 4,700,000	
11	Purchased Power Agreements	$ 26,900,000	
12	**Total Imputed Amortization Expense**	**$ 31,600,000**	
	Oregon Allocation		
13	Off-balance Sheet Debt	$ 125,776,282	Line 3 x Line 6.
14	Imputed Interest Expense	$ 7,999,711	Line 3 x Line 9.
15	Imputed Amortization	$ 8,657,222	Line 3 x Line 12.

Sources:
[1] R. Bryce Dalley Direct, Exhibit PPL/701, Page 3.
[2] Standard & Poor's: "PacifiCorp," April 1, 2009 at 7.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
Request for a General Rate Revision.	)

ICNU-CUB/321

ADJUSTED HADAWAY DCF

JULY 24, 2009

PacifiCorp Oregon

Summary of Adjusted Hadaway DCF

Line	Description	Hadaway (1)	Hadaway Adjusted* (2)
	Constant Growth DCF		
1	Average	11.4%	11.4%
2	Median	11.6%	11.6%
	Long-Term Constant Growth DCF		
3	Average	11.2%	10.1%
4	Median	11.5%	10.4%
	Multi-Stage Growth DCF		
5	Average	11.0%	10.1%
6	Median	11.1%	10.2%

Sources:

Pages 2 to 4.

* The adjustment reflects changing the GDP Growth Rate to 5.1%.

PacifiCorp Oregon

Adjusted Hadaway Constant Growth DCF Model
Analysts' Growth Rates

Line	Company	Recent Stock Price (1)	Next Year's Dividend (2)	Dividend Yield (3)	Analysts' Growth Rates: Value Line (4)	Zacks (5)	Thomson (6)	Average Growth Rate (7)	Constant Growth DCF (8)
1	ALLETE	$30.82	$1.76	5.71%	0.00%	6.50%	6.50%	4.33%	10.0%
2	Alliant Energy	$28.01	$1.50	5.36%	6.00%	6.00%	5.95%	5.98%	11.3%
3	Consol. Edison	$39.21	$2.36	6.02%	1.00%	3.30%	2.54%	2.28%	8.3%
4	DPL, Inc.	$21.51	$1.16	5.39%	11.00%	10.30%	7.43%	9.58%	15.0%
5	DTE Energy	$33.58	$2.18	6.49%	5.00%	6.00%	3.50%	4.83%	11.3%
6	Duke Energy	$14.86	$0.98	6.59%	7.00%	5.00%	4.45%	5.48%	12.1%
7	Edison Int'l	$31.10	$1.25	4.02%	6.00%	7.00%	5.49%	6.16%	10.2%
8	Entergy Corp.	$77.20	$3.00	3.89%	7.50%	7.80%	9.42%	8.24%	12.1%
9	FPL Group	$48.89	$2.00	4.09%	10.50%	9.30%	9.62%	9.81%	13.9%
10	IDACORP Inc.	$28.19	$1.20	4.26%	5.00%	6.00%	5.00%	5.33%	9.6%
11	NSTAR	$34.28	$1.63	4.75%	7.50%	7.20%	6.00%	6.90%	11.7%
12	PG&E Corp.	$37.31	$1.68	4.50%	7.00%	7.10%	7.10%	7.07%	11.6%
13	Portland General	$18.27	$1.01	5.53%	7.00%	6.30%	6.03%	6.44%	12.0%
14	Progress Energy	$38.45	$2.50	6.50%	5.50%	4.80%	5.54%	5.28%	11.8%
15	Sempra Energy	$42.95	$1.60	3.73%	7.00%	6.50%	7.59%	7.03%	10.8%
16	Southern Co.	$34.43	$1.78	5.17%	4.50%	5.00%	5.36%	4.95%	10.1%
17	Vectren Corp.	$24.85	$1.35	5.43%	5.00%	6.40%	7.20%	6.20%	11.6%
18	Wisconsin Energy	$42.68	$1.35	3.16%	8.00%	9.00%	9.13%	8.71%	11.9%
19	Xcel Energy Inc.	$18.15	$0.97	5.34%	7.50%	6.50%	6.72%	6.91%	12.3%
20	**Average**	**$33.93**	**$1.65**	**5.05%**	**6.21%**	**6.63%**	**6.35%**	**6.40%**	**11.4%**
21	**Median**			**5.34%**				**6.20%**	**11.6%**

Source:
Exhibit PPL/205, Page 2 of 5.

PacifiCorp Oregon

Adjusted Hadaway Constant Growth DCF Model
Long-Term GDP Growth

Line	Company	Recent Stock Price (1)	Next Year's Dividend (2)	Dividend Yield (3)	GDP Growth* (4)	Long-Term Constant Growth DCF (5)
1	ALLETE	$30.82	$1.76	5.71%	5.10%	10.8%
2	Alliant Energy	$28.01	$1.50	5.36%	5.10%	10.5%
3	Consol. Edison	$39.21	$2.36	6.02%	5.10%	11.1%
4	DPL, Inc.	$21.51	$1.16	5.39%	5.10%	10.5%
5	DTE Energy	$33.58	$2.18	6.49%	5.10%	11.6%
6	Duke Energy	$14.86	$0.98	6.59%	5.10%	11.7%
7	Edison Int'l	$31.10	$1.25	4.02%	5.10%	9.1%
8	Entergy Corp.	$77.20	$3.00	3.89%	5.10%	9.0%
9	FPL Group	$48.89	$2.00	4.09%	5.10%	9.2%
10	IDACORP Inc.	$28.19	$1.20	4.26%	5.10%	9.4%
11	NSTAR	$34.28	$1.63	4.75%	5.10%	9.9%
12	PG&E Corp.	$37.31	$1.68	4.50%	5.10%	9.6%
13	Portland General	$18.27	$1.01	5.53%	5.10%	10.6%
14	Progress Energy	$38.45	$2.50	6.50%	5.10%	11.6%
15	Sempra Energy	$42.95	$1.60	3.73%	5.10%	8.8%
16	Southern Co.	$34.43	$1.78	5.17%	5.10%	10.3%
17	Vectren Corp.	$24.85	$1.35	5.43%	5.10%	10.5%
18	Wisconsin Energy	$42.68	$1.35	3.16%	5.10%	8.3%
19	Xcel Energy Inc.	$18.15	$0.97	5.34%	5.10%	10.4%
20	**Average**	**$33.93**	**$1.65**	**5.05%**	**5.10%**	**10.1%**
21	**Median**			**5.34%**		**10.4%**

Sources:
Exhibit PPL/205, Page 3 of 5.
* *Blue Chip Economic Indicators,* March 10, 2009.

PacifiCorp Oregon

Adjusted Hadaway Low Near-Term Growth
Two-Stage Growth DCF Model

Line	Company	Recent Stock Price (1)	2009 Forecasted Dividend (2)	2012 Forecasted Dividend (3)	Annual Change to 2012 (4)	Cash Flows 2009 Dividend (5)	Cash Flows 2010 Dividend (6)	Cash Flows 2011 Dividend (7)	Cash Flows 2012 Dividend (8)	Cash Flows 2013 Dividend (9)	GDP Growth* (10)	Two-Stage Growth DCF (11)
1	ALLETE	$30.82	$1.76	$1.90	$0.05	$1.76	$1.81	$1.85	$1.90	$2.00	5.10%	10.4%
2	Alliant Energy	$28.01	$1.50	$1.92	$0.14	$1.50	$1.64	$1.78	$1.92	$2.02	5.10%	10.9%
3	Consol. Edison	$39.21	$2.36	$2.44	$0.03	$2.36	$2.39	$2.41	$2.44	$2.56	5.10%	10.5%
4	DPL, Inc.	$21.51	$1.16	$1.34	$0.06	$1.16	$1.22	$1.28	$1.34	$1.41	5.10%	10.5%
5	DTE Energy	$33.58	$2.18	$2.55	$0.12	$2.18	$2.30	$2.43	$2.55	$2.68	5.10%	11.6%
6	Duke Energy	$14.86	$0.98	$1.10	$0.04	$0.98	$1.02	$1.06	$1.10	$1.16	5.10%	11.5%
7	Edison Int'l	$31.10	$1.25	$1.40	$0.05	$1.25	$1.30	$1.35	$1.40	$1.47	5.10%	9.0%
8	Entergy Corp.	$77.20	$3.00	$3.30	$0.10	$3.00	$3.10	$3.20	$3.30	$3.47	5.10%	8.8%
9	FPL Group	$48.89	$2.00	$2.30	$0.10	$2.00	$2.10	$2.20	$2.30	$2.42	5.10%	9.1%
10	IDACORP Inc.	$28.19	$1.20	$1.20	$0.00	$1.20	$1.20	$1.20	$1.20	$1.26	5.10%	8.8%
11	NSTAR	$34.28	$1.63	$1.95	$0.11	$1.63	$1.74	$1.84	$1.95	$2.05	5.10%	10.0%
12	PG&E Corp.	$37.31	$1.68	$2.04	$0.12	$1.68	$1.80	$1.92	$2.04	$2.14	5.10%	9.8%
13	Portland General	$18.27	$1.01	$1.20	$0.06	$1.01	$1.07	$1.14	$1.20	$1.26	5.10%	10.7%
14	Progress Energy	$38.45	$2.50	$2.56	$0.02	$2.50	$2.52	$2.54	$2.56	$2.69	5.10%	10.9%
15	Sempra Energy	$42.95	$1.60	$2.00	$0.13	$1.60	$1.73	$1.87	$2.00	$2.10	5.10%	9.1%
16	Southern Co.	$34.43	$1.78	$2.00	$0.07	$1.78	$1.85	$1.93	$2.00	$2.10	5.10%	10.1%
17	Vectren Corp.	$24.85	$1.35	$1.47	$0.04	$1.35	$1.39	$1.43	$1.47	$1.54	5.10%	10.2%
18	Wisconsin Energy	$42.68	$1.35	$1.95	$0.20	$1.35	$1.55	$1.75	$1.95	$2.05	5.10%	9.0%
19	Xcel Energy Inc.	$18.15	$0.97	$1.06	$0.03	$0.97	$1.00	$1.03	$1.06	$1.11	5.10%	10.2%
20	**Average**	**$33.93**	**$1.65**	**$1.88**	**$0.08**	**$1.65**	**$1.72**	**$1.80**	**$1.88**	**$1.97**	**5.10%**	**10.1%**
21	**Median**											**10.2%**

Sources:
Exhibit PPL/205, Page 4 of 5.
* *Blue Chip Economic Indicators,* March 10, 2009.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
Request for a General Rate Revision.	)

ICNU-CUB/322

ACCURACY OF INTEREST RATE FORECASTS
(LONG-TERM TREASURY BOND YIELDS – PROJECTED VS. ACTUAL)

JULY 24, 2009

PacifiCorp Oregon

Accuracy of Interest Rate Forecasts

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

		Publication Data			Actual Yield	Projected Yield
Line	Date	Actual Yield (1)	Projected Yield (2)	For Quarter (3)	in Projected Quarter (4)	Higher (Lower) Than Actual Yield* (5)
1	Dec-00	5.8%	5.8%	1Q, 02	5.6%	0.2%
2	Mar-01	5.7%	5.6%	2Q, 02	5.8%	-0.2%
3	Jun-01	5.4%	5.8%	3Q, 02	5.2%	0.6%
4	Sep-01	5.7%	5.9%	4Q, 02	5.1%	0.8%
5	Dec-01	5.5%	5.7%	1Q, 03	5.0%	0.7%
6	Mar-02	5.3%	5.9%	2Q, 03	4.7%	1.2%
7	Jun-02	5.6%	6.2%	3Q, 03	5.2%	1.0%
8	Sep-02	5.8%	5.9%	4Q, 03	5.2%	0.7%
9	Dec-02	5.2%	5.7%	1Q, 04	4.9%	0.8%
10	Mar-03	5.1%	5.7%	2Q, 04	5.4%	0.3%
11	Jun-03	5.0%	5.4%	3Q, 04	5.1%	0.3%
12	Sep-03	4.7%	5.8%	4Q, 04	4.9%	0.9%
13	Dec-03	5.2%	5.9%	1Q, 05	4.8%	1.1%
14	Mar-04	5.2%	5.9%	2Q, 05	4.6%	1.4%
15	Jun-04	4.9%	6.2%	3Q, 05	4.5%	1.7%
16	Sep-04	5.4%	6.0%	4Q, 05	4.8%	1.2%
17	Dec-04	5.1%	5.8%	1Q, 06	4.6%	1.2%
18	Mar-05	4.9%	5.6%	2Q, 06	5.1%	0.5%
19	Jun-05	4.8%	5.5%	3Q, 06	5.0%	0.5%
20	Sep-05	4.6%	5.2%	4Q, 06	4.7%	0.5%
21	Dec-05	4.5%	5.3%	1Q, 07	4.8%	0.5%
22	Mar-06	4.8%	5.1%	2Q, 07	5.0%	0.1%
23	Jun-06	4.6%	5.3%	3Q, 07	4.9%	0.4%
24	Sep-06	5.1%	5.2%	4Q, 07	4.6%	0.6%
25	Dec-06	5.0%	5.0%	1Q, 08	4.4%	0.6%
26	Mar-07	4.7%	5.1%	2Q, 08	4.6%	0.5%
27	Jun-07	4.8%	5.1%	3Q, 08	4.5%	0.7%
28	Sep-07	5.0%	5.2%	4Q, 08	3.7%	1.5%
29	Dec-07	4.9%	4.8%	1Q, 09	3.5%	1.4%
30	Mar-08	4.6%	4.8%	2Q, 09		
31	Apr-08	4.4%	4.8%	3Q, 09		
32	May-08	4.4%	4.9%	3Q, 09		
33	Jun-08	4.4%	4.9%	3Q, 09		
34	Jul-08	4.6%	5.1%	4Q, 09		
35	Aug-08	4.6%	5.1%	4Q, 09		
36	Sep-08	4.6%	5.1%	4Q, 09		
37	Oct-08	4.6%	4.9%	1Q, 10		
38	Nov-08	4.5%	4.6%	1Q, 10		
39	Dec-08	4.5%	4.6%	1Q, 10		
40	Jan-09	3.8%	4.0%	2Q, 10		
41	Feb-09	3.7%	3.9%	2Q, 10		
42	Mar-09	3.7%	4.1%	2Q, 10		
43	Apr-09	3.5%	4.3%	3Q, 10		
44	May-09	3.5%	4.3%	3Q, 10		
45	Jun-09	3.5%	4.6%	3Q, 10		

Source:
Blue Chip Financial Forecasts , Various Dates.
* Col. 2 - Col. 4.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

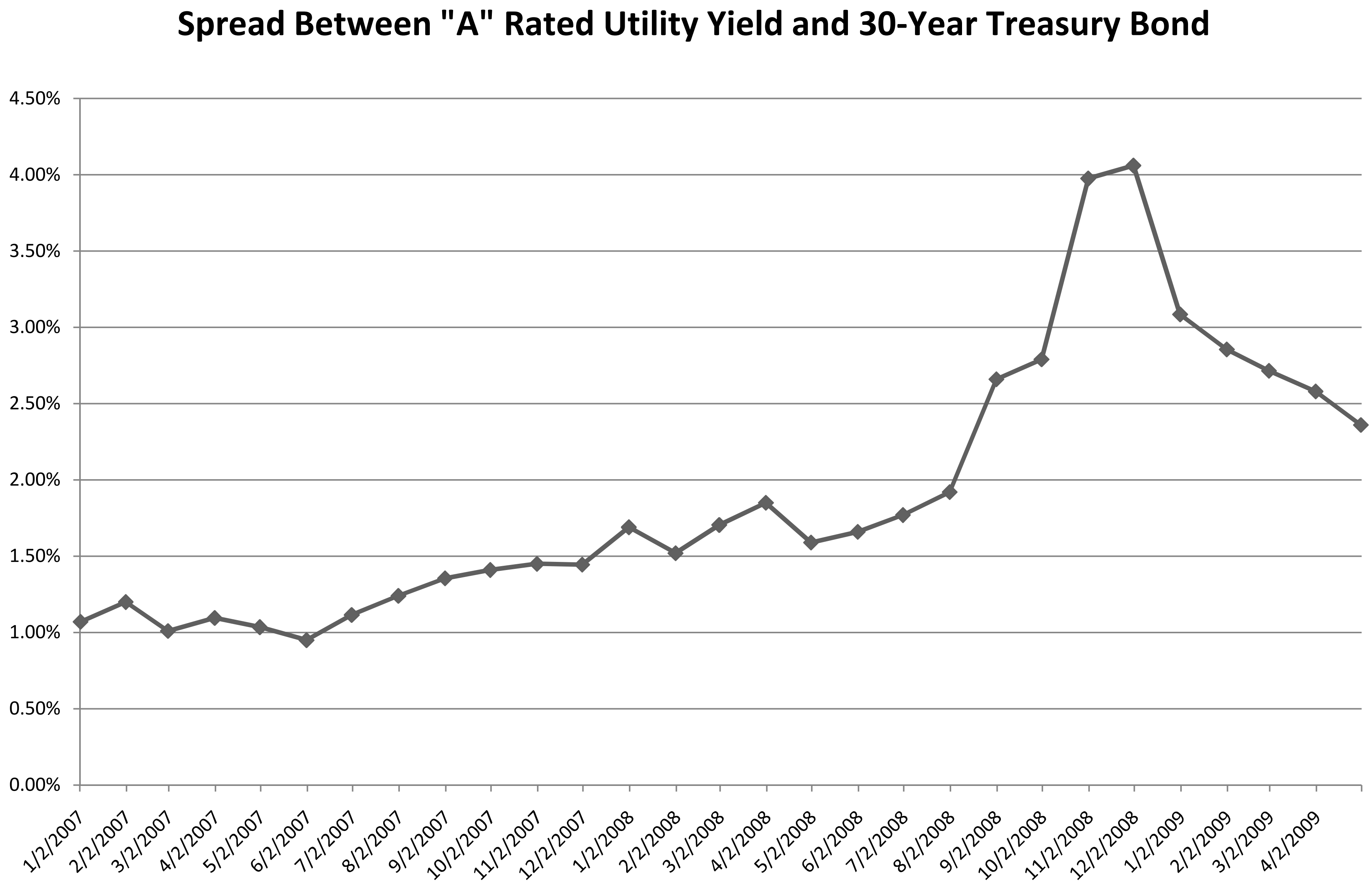
In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
Request for a General Rate Revision.	)

ICNU-CUB/323

SPREAD BETWEEN "A" RATED UTILITY YIELD AND 30-YEAR TREASURY BOND

JULY 24, 2009

PacifiCorp Oregon



BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
Request for a General Rate Revision	)
	)
____	)

REPLY TESTIMONY OF ELLEN BLUMENTHAL

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES AND

CITIZENS' UTILITY BOARD OF OREGON

July 24, 2009

I. PROFESSIONAL TRAINING AND EXPERIENCE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ellen Blumenthal. My business address is 13517 Queen Johanna Court, Corpus Christi, Texas 78418.

Q. PLEASE OUTLINE YOUR FORMAL EDUCATION.

A. I received the degree of Bachelor of Arts in Journalism from the University of Texas at Austin in 1974, but remained at the University to do additional course work in accounting and business. I became a Certified Public Accountant in Texas in 1977.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am a Principal with GDS Associates, Inc. ("GDS"). GDS is an engineering and consulting firm with offices in Marietta, Georgia; Austin, Texas; Auburn, Alabama; Manchester, New Hampshire; Madison, Wisconsin; and Avon, Indiana. GDS has over 140 employees with backgrounds in engineering, accounting, management, economics, finance, and statistics. GDS provides rate and regulatory consulting services in the electric, natural gas, water, and telephone utility industries. GDS also provides a variety of other services in the electric utility industry including power supply planning, generation support services, financial analysis, load forecasting, energy efficiency, renewable energy, and statistical services. Our clients are primarily publicly-owned utilities, municipalities, customers of privately-owned utilities, groups or associations of customers, and government agencies.

Q. PLEASE OUTLINE YOUR PROFESSIONAL EXPERIENCE.

A. From 1975 to 1977, I worked in public accounting. My public accounting experience included the preparation of financial statements, tax work, and auditing. In May 1977, I became a regulatory accountant with the Public Utility Commission of Texas.

I left the Commission in November 1980 to open an office in Austin for C.H. Guernsey & Company, Consulting Architects and Engineers. I became an independent consultant in 1982 and joined GDS in 2002. A copy of my résumé is provided as ICNU-CUB/401.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. Please see my Exhibit ICNU-CUB/401 for details of my previous appearances before this and other Commissions.

II. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The Industrial Customers of Northwest Utilities ("ICNU") and the Citizens' Utility Board of Oregon ("CUB") asked me to review PacifiCorp's ("PacifiCorp" or "Company") proposed test year 2010 employee costs. I present and explain the changes I propose to PacifiCorp's requested wages and salaries and payroll related costs such as employee benefits and incentive pay.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. Because the revenue requirement in this case is based on a projected test year, it necessarily relies on estimates of what revenues, expenses and investment will be in 2010. PacifiCorp has provided very little support for its projected wages and salaries and the related employment costs such as pensions and benefits and payroll taxes. ICNU data request ("DR") 9.15 asked PacifiCorp to provide "all workpapers, calculations, assumptions, and source documentation" for its proposed 2010 wages and salaries. PacifiCorp's response was to provide the same information contained in Section 4.2 of PPL/702 in electronic format. PacifiCorp has provided no support for the 29.5% of total company payroll it proposes to charge to Oregon in 2010, which is substantially greater than was actually charged to Oregon operations for calendar years 2007, 2008, and the first five months of 2009. The Company's 2010 projected payroll also includes approximately 311 additional employees. No mention of these additional employees is made in PacifiCorp's testimony or schedules.

I have recalculated PacifiCorp's proposed wages and salaries, excluding the additional 311 employees and excluding one-half of the bonus and incentive compensation. These expenditures benefit both customers and shareholders and should be shared equally by these stakeholders. I also recommend that the payroll allocation to Oregon be 19.7%, the actual portion allocated to Oregon for the first five months of 2009. Oregon's share of total payroll in 2007 was 19.9% and in 2008 was 18.9%.

I recalculated pensions and benefits and payroll taxes consistent with the level of payroll I recommend be included in PacifiCorp's rates for the test year ended December 31, 2010. ICNU-CUB/402 summarizes my recommendations which reduce Oregon's total wages and salaries by $60.1 million, Oregon's total pensions and benefits by $20.7 million, and Oregon's total payroll taxes by $4.4 million.

III. WAGES AND SALARIES

Q. PLEASE SUMMARIZE PACIFICORP'S REQUESTED 2010 WAGE AND SALARY LEVELS.

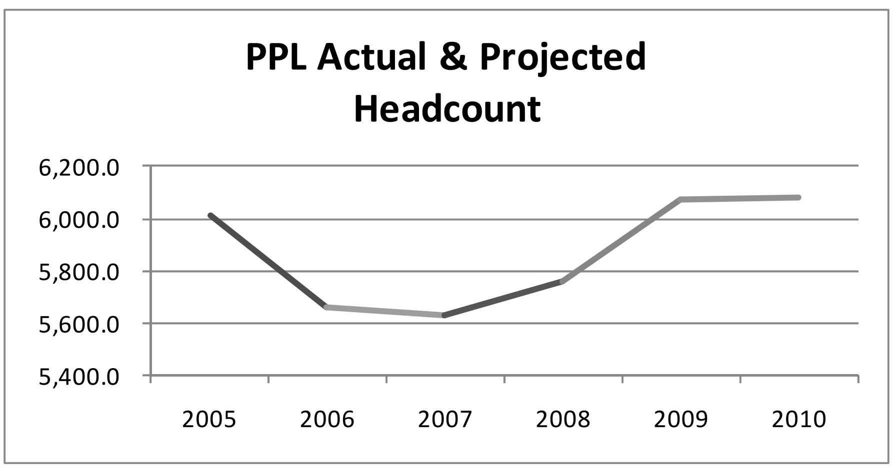
A. The test year in this case is calendar year 2010. PacifiCorp's forecasted 2010 total wages and salaries are $528,780,909, an increase of 6.3% over the actual amount for the base year ended June 30, 2008 amount. PPL/702, page 4.2.2. Approximately $34.4 million of this amount is projected incentive compensation.

Q. HOW DID PACIFICORP DEVELOP THESE FORECASTED WAGES AND SALARIES?

A. PacifiCorp "annualized" the actual payroll for the year ended June 30, 2008 to reflect pay increases for both union and non-union employees. Escalation rates were applied to these "annualized" amounts. According to PPL/702 page 4.2.2, the annualization adjustment is $6.8 million and the future test year adjustment is $24.4 million.

Q. DO THE 2010 FORECASTED WAGES INCLUDE GROWTH IN HEAD COUNT?

A. Yes. The 2010 forecasted wages include 6,113 employees, 311 more employees than the actual employee count at December 31, 2008. ICNU/403, Blumenthal/1. The graph below compares the historical headcount with the 6,113 headcount built into PacifiCorp's 2009 and 2010 forecasts.



PacifiCorp's pro forma wages and salaries also include 265 vacant positions for both 2009 and 2010. Historical vacant positions are shown for the years 2005 through 2008 in the table below. The vacant positions for 2009 and 2010 are budgeted. These values are full-time equivalents ("FTE"), but there is very little difference between headcount and FTE in this case. ICNU/403, Blumenthal/1.

Vacant Positions	
2005	111
2006	640
2007	388
2008	263
2009	265
2010	265

The wages and salaries for these vacant positions are included in the rates charged to customers. The 2010 vacant positions represent approximately $32 million of wages, benefits and payroll taxes.[1/]

Q. DID THE COMPANY ADDRESS CHANGES IN WORKFORCE LEVELS IN ITS TESTIMONY?

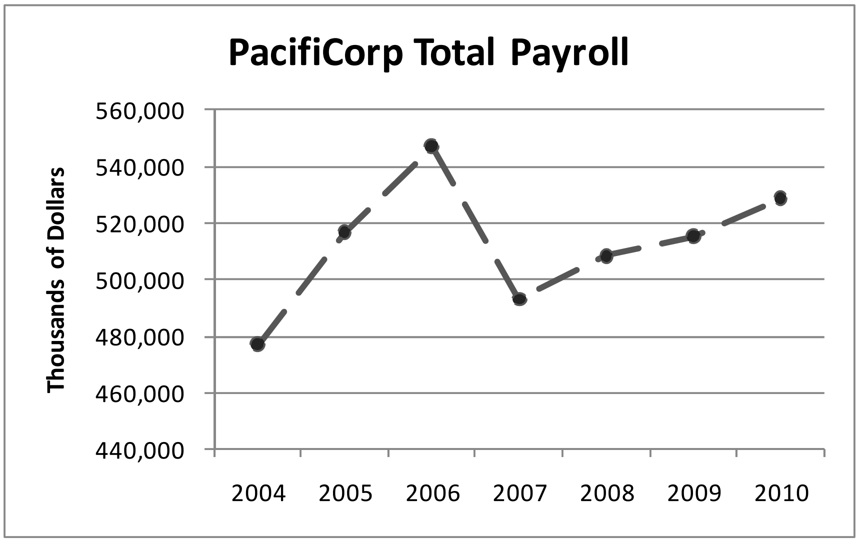
A. Yes. Mr. Dalley states at page 14 of his testimony: "The wage and employee benefit adjustment assumes a constant level of workforce based on the historical period." He goes on to say that "minor changes in workforce" are included in other adjustments, such as the costs of additional compliance staffing that is reflected in adjustment 4.17. In response to OPUC DR 165, the Company provided the headcount as of the end of each of the years 2005 through 2010. ICNU/403, Blumenthal/2. At December 31, 2008, PacifiCorp had 5,802 employees. PacifiCorp's budget for 2010 includes 6,113 employees, an increase of 311.

PacifiCorp has provided no support for the increased workforce. The costs related to the additional 311 employees should be excluded.

1/ $737.6 million divided by 6,113 employees times 265 vacant positions.

Q. HOW DO PACIFICORP'S FORECASTED WAGES AND SALARIES COMPARE WITH HISTORICAL AMOUNTS?

A. As the graph below demonstrates, PacifiCorp's wages and salaries decreased in 2007 and then began to increase again in 2008. The rates of increase projected for 2009 and 2010 are greater than the rate of increase experienced for 2008.



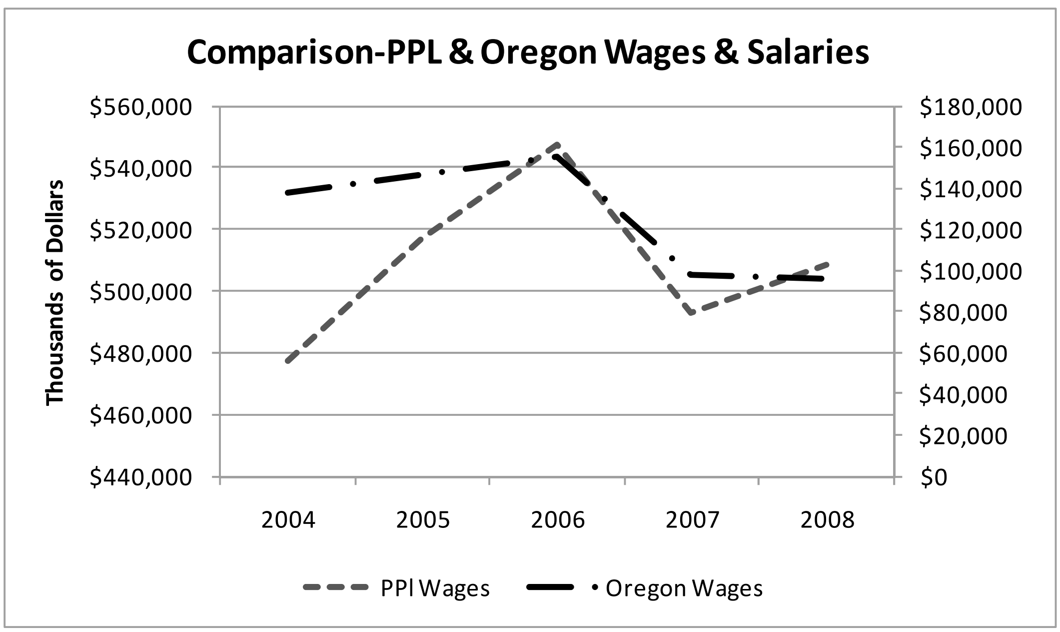
Q. WHAT WAS PACIFICORP'S FORECAST FOR WAGES AND SALARIES IN ITS LAST GENERAL RATE CASE, UE 179?

A. The test year in UE 179 was the twelve months ended December 2007. PacifiCorp projected total wages and salaries of $512,779,116 for this period. <u>Re PacifiCorp</u>, OPUC Docket No. UE 179, PPL/901, Wrigley/Table 4.3.1. Actual wages for calendar year 2007 were $493,221,406, some $20 million less than PacifiCorp projected they would be, or an overstatement of approximately 4%.

PacifiCorp's projected wages and salaries are based on internal budgets that are "prepared by each business unit at a low level that builds up to the total budget." ICNU/403, Blumenthal/3. Given that the goals for earning incentive compensation include meeting budget targets, one could expect the budgets to be generous.

Q. HOW DO PACIFICORP'S FORECASTED 2010 WAGES AND SALARIES IMPACT THE REVENUE REQUIREMENT FOR THE OREGON OPERATIONS?

A. PacifiCorp developed the 2010 rate year on a total company basis and then allocated costs to Oregon. While "[w]ages and [s]alaries and [b]enefits are allocated together" in the rate case, PacifiCorp provided the historic actual wages and salaries charged to Oregon operations for the years 2004 through 2008 in response to ICNU DR 9.8. ICNU/403, Blumenthal/4-5. The portion of total PacifiCorp wages and salaries charged to Oregon operations has been declining over the past five years, from 28.96% in 2004 to 18.86% in 2008. The graph below shows that while PacifiCorp wages and salaries have been increasing in the last few years, Oregon's wages and salaries have been decreasing.



Q. DOES PACIFICORP CARRY THIS DECLINING TREND INTO THE PROJECTED TEST YEAR 2010 FOR OREGON'S WAGES AND SALARIES?

A. No. As I mentioned earlier, PacifiCorp allocated its projected wages and salaries and benefits as a single amount. According to the Company's response to ICNU DR

9.19, Oregon operations have been allocated $155,472,689 of the 2010 pro forma labor and labor-related costs charged to expense of $527,018,069, or 29.5%. ICNU/403, Blumenthal/6-9. As the table below demonstrates, the actual labor costs charged to Oregon operations have never been as high as 29.5% during the last five calendar years:

Oregon's % of Total Labor	
2004	28.96%
2005	28.41%
2006	28.42%
2007	19.90%
2008	18.86%

For the first five months of 2009, total Oregon payroll was 19.68% of total PacifiCorp wages and salaries. ICNU/403, Blumenthal/10-21. The future test year 2010 allocation of 29.5% is unreasonable and should be replaced with the actual allocation for 2009 of 19.7%.

Q. DO PACIFICORP'S PROPOSED WAGES AND SALARIES INCLUDE BONUSES AND INCENTIVE COMPENSATION?

A. Yes. The total bonus and incentive compensation included in the Company's proposed wages and salaries is approximately $34.4 million. Mr. Wilson explains that "the objective of the Annual Incentive Plan is to provide our employees with incentive to perform at an above average level." PPL/800, Wilson/4. Mr. Wilson discusses the myriad of possible goals for employees which include Company goals as well as individual goals. Company-wide goals include controlling costs, achieving financial targets, excellent customer service, etc. An employee's personal goals are set "by reference to how that employee's position can advance the overall goals of the Company." PPL/800, Wilson/7.

The Company provided no data that demonstrates that employees who do not perform at an above average level receive no incentive compensation. While Mr. Wilson makes the global general statement "In the Company's experience, a higher level of overall employee performance is achieved when a portion of pay is 'at risk,'" he provides no qualitative data or studies as support. PPL/800, Wilson/5. Psychological studies show that many employees actually perform worse when there is a promise of a large bonus if certain goals are reached because the employee is so focused on achieving the bonus, he fails to do his job.

Q. DO THE GOALS FOR THE INCENTIVE COMPENSATION ONLY BENEFIT CUSTOMERS?

A. No. Employees work for the Company and the Company has two main constituents or stakeholders: its customers and its shareholders. Some of the goals focus on customer satisfaction while others focus on achieving targeted rates of return. When the Company operates efficiently, both of these groups benefit. Both of these groups, therefore, should share the costs incurred to incent the Company's employees to strive to achieve the Company's goals.

Q. ARE YOU RECOMMENDING THAT BONUS AND INCENTIVE COMPENSATION BE SHARED EQUALLY BETWEEN CUSTOMERS AND SHAREHOLDERS?

A. Yes. This sharing is reflected on ICNU-CUB/402.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO PACIFICORP'S REQUESTED INCREASE FOR WAGES AND SALARIES?

A. I propose three adjustments to PacifiCorp's proposed wages and salaries. My recommended adjustments are shown in Exhibit ICNU-CUB/402. The first adjustment reflects the equal sharing of bonuses and incentive compensation and is shown on line 6 of ICNU-CUB/402. The second adjustment removes the regular, overtime, and other compensation for the 311 additional employees that PacifiCorp factored into its projected 2010 amounts. The $24.9 million adjustment shown on line 5 of ICNU-CUB/402 is calculated by applying the average regular, overtime and other compensation cost per employee to the 311 additional employees. PacifiCorp provided no cost information for these positions. Therefore, this adjustment was necessarily calculated using available information.

The third adjustment reduces Oregon's share of the total Company payroll from 29.5% to 19.7%.

Based on my analyses and calculations, Oregon's total payroll amount should be approximately $96 million and the expense portion should be approximately $68.5 million.

Q. WHAT WAS OREGON'S ACTUAL PAYROLL EXPENSE FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2008?

A. According to the Company's response to ICNU data request 9.8, the actual calendar year 2008 Oregon payroll expense was $40.6 million.

IV. PENSIONS & BENEFITS, PAYROLL TAXES

Q. WHAT ADJUSTMENTS DO YOU PROPOSE FOR PENSIONS & BENEFITS AND PAYROLL TAXES?

A. In its response to OPUC DR 206, PacifiCorp corrected its projected Enhanced 401K costs. ICNU/403, Blumenthal/22. The correction reduces the total Company amount by $6.9 million. I have reflected this correction on line 11 of ICNU-CUB/402.

Pensions and benefits and payroll taxes are generally based on total wages and salaries. For example, PacifiCorp's projected 2010 pensions and benefits costs are approximately 32% of PacifiCorp's projected total wages and salaries. Payroll taxes are approximately 7.3% of PacifiCorp's projected total wages and salaries. I have maintained these relationships in PacifiCorp's projected 2010 costs for both pensions and benefits and payroll taxes in my computation of the appropriate costs based on my recommended total wages and salaries. My recommended pensions and benefits costs are approximately 32% of my recommended total wages of $486.7 million. Likewise, my recommended payroll tax costs are approximately 7.3% of my recommended total wages.

Q. IS YOUR ADJUSTMENT TO PENSIONS AND OTHER EMPLOYEE BENEFIT COSTS BASED ON YOUR ADJUSTMENT TO WAGES AND SALARIES?

A. Yes. My adjustment to pensions and other employee benefit costs is related to my wages and salaries adjustment. My testimony should not be construed as support for specific PacifiCorp pension costs.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU-CUB/401

QUALIFICATIONS OF ELLEN BLUMENTHAL

July 24, 2009

EDUCATION: University of Texas at Austin
Bachelor of Arts in Journalism, 1975
Certified Public Accountant in Texas, February 1977

PROFESSIONAL MEMBERSHIPS:
American Institute of Certified Public Accountants
Texas Society of Certified Public Accountants

EXPERIENCE:

GDS Associates, Inc., March 2002 to present

Principal of GDS Associates, Inc., Engineers and Consultants, Corpus Christi, Texas. Provides financial analysis for natural gas and electric markets; assists consumers in acquiring power needs in the competitive markets; provides analysis in gas, electric, telephone and water utility rate increase filings and presents expert testimony in regulatory proceedings on behalf of interveners. Issues addressed in testimony include all aspects of revenue requirement determination.

Independent Consultant, June 1982 to February 2002

Financial analysis for natural gas and electric markets; Provided analysis and expert witness revenue requirements testimony in gas, electric, telephone and water utility rate increase applications on behalf of intervenors.

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C. H. Guernsey & Co., Consulting Engineers & Architects, November 1980 - June 1982

Title: Regulatory Accountant and Financial Analyst

Duties included preparation of financial and accounting aspects of rate filings for electric cooperatives for presentation before the Public Utility Commission of Texas. Testified as an expert witness on accounting matters before the Public Utility Commission of Texas. Advised electric cooperatives on accounting and regulatory matters. Participated in review of rate increase applications of investor-owned utilities and prepared and presented expert witness testimony based on such review. Participated in special projects such as cost-benefit analyses related to owner participation in power plants and alternative regulatory treatments for nuclear generating stations.

Public Utility Commission of Texas, May 1977 - November 1980

Title: Chief Accountant III

Duties included providing expert witness testimony in investor-owned and cooperative telephone, electric and water utility rate cases filed with the Commission in the following areas: Fuel and purchased power, Operation and maintenance expenses, Federal income taxes, Taxes other than federal income taxes, Affiliate transactions, Oil and gas exploration and development. Reviewed the books and business records of public utilities to determine the reasonableness of rate requests. Reviewed public utilities' implementation of fuel adjustment clause and other rate schedules to determine compliance with tariffs approved by Commission.

Sample List of Testimony Filed and Other Utility Projects:

Application of Oncor Electric Delivery Company LLC for Authority to Change Rates, Texas Public Utility Commission Docket No. 35717, November 2008.

Advisor to Nebraska Public Service Commission on gas utility regulatory matters. 2003 to present.

Portland General Electric Company General Rate Case, Oregon Public Utility Commission Docket UE 197, July 2008.

Petition of PNM Resources, Inc. and Cap Rock Energy Corporation Regarding Merger and Acquisition of Stock, Texas Public Utility Commission Docket No. 35640, June 2008.

Application of Entergy Gulf States for Authority to Change Rates, Texas Public Utility Commission Docket No. 34800, April 2008.

Pacific Power & Light (dba PacifiCorp) to File Tariffs Establishing Automatic Adjustment Clause under the Terms of SB 408 on behalf of the Industrial Customers of Northwest Utilities, Public Utility Commission of Oregon Docket No. UE 177, January 22, 2008.

Petition by New Mexico Utilities, Inc. for Authority to Amend Its Wastewater Rates, New Mexico Public Regulation Commission Case No. 07-00435-UT, November 2007.

United Water Connecticut, Inc. Application to Change Rates, Prepare rate filing and testimony. Connecticut Department of Public Utilities Docket No. 07-05-44, June 2007.

Application of AEP Texas Central Company for Authority to Change Rates, Texas Public Utility Commission Docket No. 33309, March 2007.

Application of AEP Texas North Company for Authority to Change Rates, Texas Public Utility Commission Docket No. 33310, March 2007.

Staff's Petition for a Reallocation of Stranded Costs Pursuant to PURA Sec. 139.253(f), Texas PUC Docket No. 32795, August 2006.

Application of Bryan Texas Utilities for Interim Update of Wholesale Transmission Rates Pursuant to Substantive Rule 25.192(g)(1), Texas Public Utility Commission Docket No. 30925, March 2005; Docket No. 32958, June 2006.

Application of AEP Texas Central Company for a Financing Order, Texas Public Utility Commission Docket No. 32475, April 2006.

Application of Texas-New Mexico Power Company to Establish a Competition Transition Charge Pursuant to P.U.C. SUBST. R. 25.263(n), Texas Public Utility Commission Docket No. 31994, March 2006.

Application of the Electric Reliability Council of Texas for Approval of the ERCOT System Administration Fee, Texas Public Utility Commission Docket No. 31824, January 2006.

Application of Entergy Gulf States, Inc. for Recovery of Transition to Competition Costs, Texas Public Utility Commission Docket No. 31544, January 2006.

Application of Sharyland Utilities, L.P. for Interim Update of Wholesale Transmission Rates Pursuant to Substantive Rule 25.192(g)(1), Texas Public Utility Commission Docket No. 31826, October 2005.

Two management audits of the Sempra Energy utilities' compliance with federal and state affiliate rules. October 2005

Petition to Inquire into the Reasonableness of the Rates and Services of Cap Rock Energy Corporation, Texas Public Utility Commission Docket No. 28813 on behalf of Pioneer Energy, August 2004.

Application of CenterPoint Energy Houston Electric, LLC, Texas Genco, LP, and Reliant Energy Retail Services, LLC to Determine Stranded Costs and Other Balances, Texas PUC Docket No. 29526, on behalf of the City of Houston and the Coalition of Cities, June 2004.

Application of AEP Texas Central Company for Authority to Change Rates, Texas PUC Docket No. 28840, on behalf of the Coalition of Commercial Ratepayers, February 2004.

Application of the Electric Reliability Council of Texas to Change the ERCOT System Administrative Fee, Texas PUC Docket No. 28832, on behalf of the Office of Public Utility Counsel, January 2004.

TXU Gas Company Statement of Intent to Change Rates in the Company' s Statewide Gas Utility System, Texas Railroad Commission Docket No. 9400, on behalf of Allied Coalition of Cities, December 2003.

Application of Southwestern Electric Power Company for Authority to Reconcile Fuel Costs, Texas PUC Docket No. 28045, on behalf of the Cities Served, November 2003.

Kansas Gas Service, a Division of Oneok, Inc. Application to Change Natural Gas Rates, Kansas Corporation Commission Docket 03-KGSG-602-RTS, on behalf of Unified School District No. 259, July 2003

Application of AEP Texas Central Company for Authority to Reconcile Fuel Costs, Texas PUC Docket No. 27035 on behalf of Affected Cities, April 2003.

Application of West Texas Utilities Company for Authority to Reconcile Fuel Costs, Texas PUC Docket No. 26000 on behalf of the Office of Public Utility Counsel, October 2002.

TXU Gas Distribution Application to Change Distribution Rates in its South Region on behalf of affected Texas municipalities, Fall 2002.

Application of Ernest G. Johnson, Director of the Public Utility Division, Oklahoma Corporation Commission to Review the Rates, Charges, Services and Service Terms of Oklahoma Gas & Electric Company and all Affiliated Companies and any Affiliate or Non-Affiliate Transaction Relevant to Such Inquiry, Oklahoma Corporation Commission Cause No. PUD 200100455 on behalf of the Oklahoma Attorney General, June 2002.

Petition of the Electric Reliability Council of Texas for Approval of the ERCOT Administrative Fee, Texas PUC Docket No. 23320 on behalf of Austin Energy, May 2002.

Texas-New Mexico Power Company Application for Approval of Unbundled Cost of Service Rates, Texas PUC Docket No. 22349 on behalf of the Office of Public Utility Counsel, January 2001.

TXU Lone Star Pipeline Application to Change the City Gate Rate, Texas Railroad Commission Docket No. 8976 on behalf of the Aligned Cities, January 2000.

Reliant Energy HL&P Application for Approval of Unbundled Cost of Service Rates, Texas PUC Docket No. 22355 on behalf of the City of Houston and the Coalition of Cities, December 2000.

TXU Electric Company Application for Approval of Unbundled Cost of Service Rates, Texas PUC Docket No. 22350 on behalf of the Office of Public Utility Counsel, October 2000.

Santa Fe Pipeline Partnership, L.P., FERC Docket No. OR92-8-000, *et al* on behalf of Refinery Holding Company, L.P., January 1996.

Peoples Natural Gas Company, Rate Area Three on behalf of the Nebraska Municipalities Served, December 1995.

Compliance review of Southern Union Gas Company's fuel cost recovery in the City of El Paso on behalf of the City of El Paso, Texas, Spring 1995.

Houston Lighting and Power Company, Texas PUC Docket No. 12065 on behalf of Office of Public Utility Counsel, November 1994.

El Paso Electric Company, Texas PUC Docket No. 12700 on behalf of Office of Public Utility Counsel and The City of El Paso, Texas, June 1994.

Application of Central and South West Corporation and El Paso Electric Company For Approval of Acquisition, PUC Docket No. 12700 on behalf of Office of Public Utility Counsel, June 1994.

El Paso Electric Company, Public Utility Regulation Board of The City of El Paso, Texas on behalf of the City of El Paso, Texas, May 1994.

Kansas Pipeline Partnership and Kansas Natural Partnership, Kansas Docket No. 190,362-U on behalf of Citizens' Utility Ratepayer Board, September 1994.

KN Energy, Inc., Kansas Corporation Commission Docket No. 186,363-U on behalf of Citizens' Utility Ratepayer Board, September 1993.

City of Austin Water and Wastewater Utility before City Counsel on behalf of residential and small commercial ratepayers, October 1993.

Texas Utilities Electric Company, Texas PUC Docket No. 11735 on behalf of Certain Cities Served by Texas Utilities Electric Company, September 1993.

Complaint of General Counsel against Cherokee County Electric Cooperative, Inc. regarding application of Cherokee's switchover tariff, Texas PUC Docket No. 11351, on behalf of the Cooperative, June 1993.

Texas Utilities Electric Company, Texas PUC Docket No.11735 on behalf of the Office of Public Utility Counsel, April 1993.

Application of Entergy Corporation and GSU for Sale, Transfer or Merger, Texas PUC Docket No. 11292, on behalf of Office of Public Utility Counsel, January 1993.

Peoples Natural Gas Company, Kansas Corporation Commission Docket No. 180,416-U, on behalf of the Citizens' Utility Ratepayer Board, August 1992.

Kansas Public Service Company, Kansas Corporation Commission Docket No. 179,484-U, on behalf of the Citizens' Utility Ratepayer Board, April 1992.

Complaint of NBC Telecommunications, Inc. against Southwestern Bell Telephone Company, Texas PUC Docket No. 10762, on behalf of complainant, September 1992.

Central Texas Telephone Company, Texas PUC Docket No. 9981, on behalf of the Office of Public Utility Counsel, December 1991.

Texas-New Mexico Power Company, Texas PUC Docket No. 10200, on behalf of the Office of Public Utility Counsel, December 1991.

Greeley Gas Company, Kansas Corporation Commission Docket No. 177,142-U, on behalf of the Citizens' Utility Ratepayers Board, November 1991.

Peoples Natural Gas Company, Rate Areas Two and Three on behalf of the Nebraska Municipalities Served, November 1991.

Southern Union Gas Company El Paso Service Area, Public Utility Regulatory Board of El Paso on behalf of the City of El Paso, November 1991.

City of Round Rock, Texas Water Commission Docket No. 8600-M, on behalf of Brushy Creek Municipal Utility District, October 1991.

El Paso Electric Company, Texas PUC Docket No. 9945, on behalf of the Office of Public Utility Counsel, April 1991.

Houston Lighting & Power Company, Texas PUC Docket No. 9850, on behalf of the Office of Public Utility Counsel, February 1991.

Greeley Gas Company, Kansas Corporation Commission Docket No. 170,588-U, on behalf of the Citizens' Utility Ratepayers Board, August 1990.

Rio Grande Valley Gas Company, Texas Railroad Commission Docket No. 7604, Consolidated, on behalf of the Intervener Cities, May 1990.

Southern Union Gas Company El Paso Service Area, Public Utility Regulatory Board of El Paso on behalf of the City of El Paso, October 1990.

Texas Utilities Electric Company, Texas PUC Docket No. 9300, on behalf of the Intervener Cities, April 1990.

Gulf States Utilities Company, Texas PUC Docket No. 8702, on behalf of the Intervener Cities, July 1989.

Central Power & Light Company, Texas PUC Docket No. 8646, on behalf of the Intervener Cities, June 1989.

Lower Colorado River Authority, Texas PUC Docket No. 8400, on behalf of several wholesale customers, February 1989.

Lower Colorado River Authority, Texas PUC Docket No. 8032, on behalf of several wholesale customers, June 1988.

Tawakoni Water Utility Corporation, Texas Water Commission Docket No. 7368-R, on behalf of Tawakoni Water Consumers Association, January 1988.

Hill Country Waterworks Company, Texas Water Commission Docket No. 172-W, on behalf of the City of Hill Country Village and the City of Hollywood Park, July 1987.

Detroit Edison Company, Michigan PSC, Case No. U-8683, on behalf of North Star Steel Michigan, May 1987.

Gulf States Utilities Company, Texas PUC Docket No. 7195, on behalf of North Star Steel Texas, January 1987.

Rio Grande Valley Gas Company, Texas Railroad Commission Docket No. 4717, 1984 and Docket No. 3858, on behalf of the Rio Grande Valley Cities, March 1982.

Lower Colorado River Authority, Texas PUC Docket No. 6027, on behalf of several wholesale customers, March 1985.

Houston Lighting and Power Company, Texas PUC Docket No. 4540, August 1982, on behalf of the City of Houston.

Houston Lighting & Power Company, Texas PUC Docket No. 3320, September 1980, on behalf of the Texas Public Utility Commission.

Inquiry by Public Utility Commission of Texas into Certain Affiliate transactions of Texas Electric Service Company, Texas Power and Light Company and Dallas Power and light Company, Texas PUC Docket Nos. 1517, 1813 and 1903, February 1979, on behalf of the Texas Public Utility Commission.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU-CUB/402

TOTAL WAGES AND SALARIES

July 24, 2009

PacifiCorp
Total Wages and Salaries
Test Year Ended December 31, 2010

		PPL Proposal			ICNU Adjustments		
Wages & Salaries		Total Co		Oregon	Total Co		Oregon
1	Regular, overtime & other compensation	$ 494,351,756	29.50%	$ 145,833,768	$ 494,351,756	19.70%	$ 97,387,296
2	Bonuses & incentive compensation	34,429,153	29.50%	10,156,600	34,429,153	19.70%	6,782,543
3	Total wages & salaries	$ 528,780,909		$ 155,990,368	$ 528,780,909		$ 104,169,839
4	ICNU recommended adjustments:						
5	Regular, overtime & other compensation				(24,871,674)	19.70%	(4,899,720)
6	ICNU bonue & incentive compensation adjustment				(17,214,577)	19.70%	(3,391,272)
7	ICNU recommended wages & salaries				$ 486,694,659		$ 95,878,848
8	Non-utility & capital	(150,965,900)		(44,534,940)	(138,950,359)	19.70%	(27,373,221)
9	Wages & Salaries Expense	$ 377,815,010		$ 111,455,428	$ 347,744,300		$ 68,505,627
Pensions & Benefits							
10	Total Pensions & Benefits	$ 170,119,604	29.50%	$ 50,185,283	$ 156,579,599	19.70%	$ 30,846,181
11	Correct Enhanced 401K amount per OPUC 206	(6,919,258)	29.50%	(2,041,181)	(6,919,258)	19.70%	(1,363,094)
12	Corrected total pensions & benefits	$ 163,200,346		$ 48,144,102	$ 149,660,341		$ 29,483,087
13	Non-utility & capital	(48,568,809)		(14,327,799)	(44,703,165)	19.70%	(8,806,523)
14	Pensions & Benefits Expense	$ 114,631,537		$ 33,816,303	$ 104,957,176		$ 20,676,564
Payroll Taxes							
13	Total payroll taxes	$ 38,701,452	29.50%	$ 11,416,928	$ 35,621,161	19.70%	$ 7,017,369
14	Non-utility & capital	(11,049,188)	29.50%	(3,259,510)	(10,169,771)	19.70%	(2,003,445)
15	Payroll tax expense	$ 27,652,264		$ 8,157,418	$ 25,451,391		$ 5,013,924

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 210

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Request for a General Rate Revision	)

ICNU-CUB/403

PACIFICORP RESPONSES TO
ASSORTED DATA REQUESTS

July 24, 2009

UE-210/PacifiCorp
June 5, 2009
OPUC Data Request 279

OPUC Data Request 279

As a follow up to PPL's response to Data Request no. 167 a-f, please provide the same information provided for 2005 through 2008 in the same categories (union, non-exempt, exempt and officer; excluding over-time) for the 2009 and 2010 budgeted forecast.

Response to OPUC Data Request 279

a. Wages and salaries, annualized as of end-of-period, for each PP&L employee category (union, nonexempt, exempt and officer). Exclude overtime, bonuses and incentive pay. Please see Attachment 279a.

b. Average and end-of-period numbers of employees by employee category. Include part-time and temporary employees as full-time equivalents. Please see Attachment 279b.

c. For each employee category for each period, O & M expense as a percentage of payroll expense and capitalized labor as a percentage of payroll expense. Please see Attachment 279c.

d. Overtime costs by employee category including the select set of exempt first line supervisor positions PP&L indicated were eligible for straight time overtime inquired about in Data Request No. 171 below. Please see Attachment 279d.

e. Bonuses and incentive pay for each employee category. The original Attachment OPUC 167e was not consistent with the definition of Bonuses and incentive pay in the filing. This has been restated in Attachment 279e, along with the totals included in the future periods in the filing.

f. Annual turnover ratios. These are not estimated for future years.

Please refer to non-confidential Attachments OPUC 279 –(a-e) on the enclosed CD.

UE-210/PacifiCorp
May 7, 2009
OPUC Data Request 165

OPUC Data Request 165

Please provide (a) the actual number of full-time equivalent positions for the years 2005 through 2008 and (b) the number budgeted for 2009 and 2010 for each of the following categories: Administrative & General, Transmission & Distribution, and Company Total.

Response to OPUC Data Request 165

Administrative and General is not a category of employees, but is a function that employees in any area of the Company can charge time to. Therefore, the Company cannot provide a count of Administrative and General employees. The Company relies on full-time and part-time headcount, rather than full-time equivalent positions ("FTEs"), for budgeting and planning purposes. As a result, the Company has provided the information requested by Staff using headcount, as this is the information that is currently available and is most useful to Staff in analyzing the Company's employment data. Nevertheless, the Company will provide the information requested by Staff on an FTE-basis by May 12, 2009.

Transmission and Distribution full-time and part-time headcount at the end of each year is as follows:

December 31, 2005	2,196
December 31, 2006	2,046
December 31, 2007	2,055
December 31, 2008	2,138
December 31, 2009	2,238
December 31, 2010	2,238

Total Company full-time and part-time headcount at the end of each year is as follows:

December 31, 2005	6,060
December 31, 2006	5,697
December 31, 2007	5,669
December 31, 2008	5,802
December 31, 2009	6,110
December 31, 2010	6,113

UE-210/PacifiCorp
July 15, 2009
OPUC Data Request 340

OPUC Data Request 340

Regarding the adjustment made on page 4.20 of PPL exhibit 702, please provide the following:

a. Of the $11,338,058 Oregon allocated adjustment, what portion of this adjustment is related to labor and what portion is related to non-labor? How is this determination made?
b. Please provide an explanation on whether PacifiCorp able to identify specific expense items and or SAP accounts which have adjusted? If so, please provide a detailed listing of the specific items which have been adjusted.

Response to OPUC Data Request 340

a. The adjustment on page 4.20 of PPL Exhibit/702 adjusts non-power cost O&M in the case to the total CY 2010 non-power cost O&M in the budget. The adjustment is prepared on a total basis and is not split between labor and non-labor components.
b. The budget is not prepared on a FERC account basis. It is prepared by each business unit at a low level that builds up to the total budget. FERC-based non-power O&M in the case cannot be compared to the budget on a detailed basis.

UE-210/PacifiCorp
July 2, 2009
ICNU 9th Set Data Request 9.20

ICNU Data Request 9.20

Provide the amount of employee benefits included in each line item for each of the four columns presented on page 2.2 of the company's application (Results of Operations Summary).

Response to ICNU Data Request 9.20

Wages and Salaries and Benefits are allocated together. Please refer to the Company's response to ICNU Data Request 9.19; specifically Attachment ICNU 9.19.

UE-210/PacifiCorp
July 2, 2009
ICNU 9th Set Data Request 9.8

ICNU Data Request 9.8

Provide the following information for Pacific Power Oregon for each of the calendar years 2008, 2007, 2006, 2005, and 2004:

a. Total wages and salaries
b. Total wages and salaries charged to accounts 500 through 932
c. Total wages and salaries charged to capital or other balance sheet accounts
d. Total regular wages and salaries
e. Total overtime wages and salaries.

Response to ICNU Data Request 9.8

Please refer to Attachment ICNU 9.8 for the total-Company and Oregon-allocated share of the requested wage and salary information. For 2007 and 2008, PacifiCorp began using FERC 707 for a labor clearing account. The total salary and wages are booked to FERC 707 and allocated out to the various other FERC accounts using labor allocations from time entry. The response provided shows only the total wages and salaries booked and excludes all labor allocation activity since this is considered secondary labor. FERC 707 has a zero balance on a consolidated basis.

Please refer to non-confidential Attachment ICNU 9.8 on the enclosed CD.

UE-210/PacifiCorp
July 2, 2009
ICNU 9th Set Data Request 9.19

ICNU Data Request 9.19

Provide the amount of wages and salaries included in each line item for each of the four columns presented on page 2.2 of the company's application (Results of Operations Summary).

Response to ICNU Data Request 9.19

Wages and Salaries, and Benefits are allocated together. Please refer to Attachment ICNU 9.19.

Please refer to non-confidential Attachment ICNU 9.19 on the enclosed CD.

ALLOCATION OF LABOR

		JUNE 2008 UNADJUSTED RESULTS		DECEMBER 2010 PRO FORMA RESULTS		
Account	Allocation Factor	TOTAL	OREGON	TOTAL	OTHER	OREGON
500	SG	15,647,397	4,205,533	16,728,937	12,232,720	4,496,217
501	SE	1,090,932	272,754	1,166,336	874,730	291,606
502	SG	18,556,510	4,987,412	19,839,126	14,506,987	5,332,139
503	SE	38,037	9,510	40,666	30,499	10,167
505	SG	1,570,655	422,143	1,679,217	1,227,896	451,321
506	SG	36,762,559	9,880,631	39,303,569	28,739,994	10,563,575
506	SSGCH	(15,249)	(4,196)	(16,303)	(11,817)	(4,487)
510	SG	2,510,626	674,778	2,684,159	1,962,741	721,418
511	SG	7,034,046	1,890,532	7,520,235	5,499,030	2,021,205
511	SSGCH	(8,637)	(2,377)	(9,234)	(6,693)	(2,541)
512	SG	25,867,642	6,952,416	27,655,601	20,222,637	7,432,964
512	SSGCH	(385,817)	(106,174)	(412,484)	(298,971)	(113,513)
513	SG	9,846,530	2,646,440	10,527,117	7,697,756	2,829,361
513	SSGCH	(103)	(28)	(110)	(80)	(30)
514	SG	2,329,844	626,189	2,490,882	1,821,410	669,471
514	SSGCH	(130,797)	(35,994)	(139,837)	(101,355)	(38,482)
535	SG-P	4,082,398	1,097,221	4,364,571	3,191,511	1,173,061
535	SG-U	3,740,331	1,005,284	3,998,860	2,924,091	1,074,769
536	SG-P	68,674	18,457	73,421	53,687	19,733
537	SG-P	442,576	118,951	473,167	345,994	127,172
537	SG-U	100,128	26,911	107,049	78,277	28,771
539	SG-P	3,832,182	1,029,971	4,097,061	2,995,898	1,101,162
539	SG-U	3,339,478	897,548	3,570,301	2,610,716	959,586
540	SG-P	(185)	(50)	(197)	(144)	(53)
542	SG-P	257,236	69,137	275,016	201,100	73,916
542	SG-U	28,729	7,721	30,714	22,459	8,255
543	SG-P	382,152	102,711	408,566	298,756	109,810
543	SG-U	215,848	58,013	230,768	168,745	62,023
544	SG-P	816,901	219,557	873,364	638,631	234,733
544	SG-U	323,156	86,854	345,493	252,635	92,858
545	SG-P	420,319	112,969	449,371	328,594	120,777
545	SG-U	204,481	54,958	218,614	159,858	58,757
546	SG	116,449	31,298	124,498	91,037	33,461
548	SG	3,261,951	876,711	3,487,415	2,550,107	937,309
548	SSGCT	2,066,041	519,966	2,208,844	1,652,938	555,906
549	SG	789,652	212,234	844,232	617,329	226,903
552	SG	43,718	11,750	46,740	34,178	12,562
552	SSGCT	167,000	42,029	178,543	133,609	44,934
553	SG	1,706,077	458,540	1,824,000	1,333,766	490,234
553	SSGCT	323,417	81,395	345,772	258,751	87,021
554	SG	9,342	2,511	9,987	7,303	2,684
554	SSGCT	138,084	34,752	147,628	110,474	37,154
556	SG	791,621	212,763	846,338	618,869	227,469
557	SG	34,728,033	9,333,813	37,128,418	27,149,456	9,978,962
557	SSGCT	70,076	17,636	74,920	56,065	18,855
560	SG	5,950,426	1,599,289	6,361,717	4,651,886	1,709,831
561	SG	6,662,456	1,790,661	7,122,962	5,208,532	1,914,430
562	SG	953,031	256,145	1,018,904	745,054	273,850
563	SG	(493,518)	(132,642)	(527,629)	(385,819)	(141,810)
566	SG	113,952	30,627	121,828	89,085	32,744
567	SG	200,038	53,764	213,865	156,384	57,480
568	SG	17,121	4,602	18,305	13,385	4,920
569	SG	2,339,781	628,860	2,501,506	1,829,179	672,327
570	SG	5,615,302	1,509,218	6,003,429	4,389,894	1,613,535
571	SG	921,166	247,581	984,836	720,143	264,693
572	SG	-	-	-	-	-
573	SG	30,202	8,117	32,289	23,611	8,678
580	SNPD	20,078,572	5,702,046	21,466,393	15,370,224	6,096,168
580	UT	660	-	705	705	-
580	WYP	205	-	219	219	-
581	SNPD	12,203,508	3,465,633	13,047,008	9,341,832	3,705,176
582	CA	61,335	-	65,574	65,574	-
582	IDU	115,196	-	123,158	123,158	-
582	OR	732,652	732,652	783,293	-	783,293
582	SNPD	(9,601)	(2,727)	(10,265)	(7,350)	(2,915)
582	UT	896,110	-	958,048	958,048	-
582	WA	157,508	-	168,395	168,395	-
582	WYP	412,005	-	440,483	440,483	-
583	CA	10,161	-	10,863	10,863	-
583	IDU	(127,770)	-	(136,601)	(136,601)	-
583	OR	362,368	362,368	387,415	-	387,415
583	SNPD	138,024	39,197	147,565	105,658	41,906
583	UT	344,075	-	367,857	367,857	-
583	WA	(87,033)	-	(93,049)	(93,049)	-
583	WYP	93,931	-	100,424	100,424	-

Account	Allocation Factor	JUNE 2008 UNADJUSTED RESULTS TOTAL	JUNE 2008 UNADJUSTED RESULTS OREGON	DECEMBER 2010 PRO FORMA RESULTS TOTAL	DECEMBER 2010 PRO FORMA RESULTS OTHER	DECEMBER 2010 PRO FORMA RESULTS OREGON
583	WYU	127,975	-	136,820	136,820	-
584	CA	(25,312)	-	(27,062)	(27,062)	-
584	OR	(169,156)	(169,156)	(180,848)	-	(180,848)
584	UT	(3,321)	-	(3,551)	(3,551)	-
584	WA	(18,810)	-	(20,110)	(20,110)	-
584	WYP	(3,216)	-	(3,438)	(3,438)	-
585	SNPD	293,833	83,445	314,143	224,931	89,212
586	CA	164,375	-	175,737	175,737	-
586	IDU	228,839	-	244,657	244,657	-
586	OR	1,812,238	1,812,238	1,937,499	-	1,937,499
586	SNPD	961,666	273,100	1,028,136	736,159	291,977
586	UT	1,128,919	-	1,206,949	1,206,949	-
586	WA	602,271	-	643,899	643,899	-
586	WYP	399,333	-	426,934	426,934	-
586	WYU	33,936	-	36,282	36,282	-
587	CA	724,859	-	774,961	774,961	-
587	IDU	807,052	-	862,835	862,835	-
587	OR	4,538,353	4,538,353	4,852,042	-	4,852,042
587	UT	4,321,721	-	4,620,436	4,620,436	-
587	WA	935,685	-	1,000,359	1,000,359	-
587	WYP	728,569	-	778,927	778,927	-
587	WYU	95,567	-	102,172	102,172	-
588	CA	37,676	-	40,280	40,280	-
588	IDU	114,484	-	122,397	122,397	-
588	OR	1,196,085	1,196,085	1,278,757	-	1,278,757
588	SNPD	17,398,472	4,940,933	18,601,046	13,318,598	5,282,448
588	UT	1,340,124	-	1,432,753	1,432,753	-
588	WA	130,862	-	139,907	139,907	-
588	WYP	183,417	-	196,094	196,094	-
588	WYU	20,202	-	21,599	21,599	-
589	CA	21,006	-	22,458	22,458	-
589	IDU	3,903	-	4,173	4,173	-
589	OR	83,744	83,744	89,533	-	89,533
589	SNPD	-	-	-	-	-
589	UT	40,357	-	43,146	43,146	-
589	WA	8,653	-	9,251	9,251	-
589	WYP	37,016	-	39,575	39,575	-
589	WYU	4,696	-	5,020	5,020	-
590	CA	27,017	-	28,884	28,884	-
590	IDU	(31,675)	-	(33,864)	(33,864)	-
590	OR	176,946	176,946	189,176	-	189,176
590	SNPD	7,556,145	2,145,844	8,078,422	5,784,259	2,294,164
590	UT	(164,534)	-	(175,907)	(175,907)	-
590	WA	13,036	-	13,937	13,937	-
590	WYP	1,506	-	1,610	1,610	-
592	CA	460,625	-	492,464	492,464	-
592	IDU	390,655	-	417,657	417,657	-
592	OR	1,858,102	1,858,102	1,986,533	-	1,986,533
592	SNPD	2,330,407	661,805	2,491,484	1,783,936	707,548
592	UT	2,337,915	-	2,499,511	2,499,511	-
592	WA	255,956	-	273,648	273,648	-
592	WYP	678,672	-	725,582	725,582	-
592	WYU	-	-	-	-	-
593	CA	2,448,577	-	2,617,821	2,617,821	-
593	IDU	1,893,780	-	2,024,678	2,024,678	-
593	OR	10,904,929	10,904,929	11,658,672	-	11,658,672
593	SNPD	255,621	72,593	273,289	195,679	77,610
593	UT	5,241,393	-	5,603,675	5,603,675	-
593	WA	1,880,614	-	2,010,601	2,010,601	-
593	WYP	1,576,210	-	1,685,157	1,685,157	-
593	WYU	288,986	-	308,960	308,960	-
594	CA	660,760	-	706,431	706,431	-
594	IDU	419,282	-	448,263	448,263	-
594	OR	3,704,164	3,704,164	3,960,194	-	3,960,194
594	SNPD	5,303	1,506	5,669	4,059	1,610
594	UT	7,267,885	-	7,770,238	7,770,238	-
594	WA	669,186	-	715,440	715,440	-
594	WYP	798,431	-	853,618	853,618	-
594	WYU	189,300	-	202,385	202,385	-
595	OR	38,476	38,476	41,135	-	41,135
595	SNPD	734,591	208,614	785,366	562,332	223,033
595	UT	4,934	-	5,275	5,275	-
595	WYP	(11,100)	-	(11,868)	(11,868)	-
596	CA	87,717	-	93,780	93,780	-
596	IDU	129,737	-	138,704	138,704	-
596	OR	615,771	615,771	658,332	-	658,332
596	UT	346,190	-	370,119	370,119	-

		JUNE 2008 UNADJUSTED RESULTS		DECEMBER 2010 PRO FORMA RESULTS		
Account	Allocation Factor	TOTAL	OREGON	TOTAL	OTHER	OREGON
596	WA	149,795	-	160,148	160,148	-
596	WYP	192,529	-	205,837	205,837	-
596	WYU	41,842	-	44,734	44,734	-
597	CA	43,727	-	46,750	46,750	-
597	IDU	227,961	-	243,717	243,717	-
597	OR	956,725	956,725	1,022,854	-	1,022,854
597	SNPD	1,380,374	392,008	1,475,785	1,056,682	419,103
597	UT	1,208,468	-	1,291,997	1,291,997	-
597	WA	325,367	-	347,856	347,856	-
597	WYP	453,204	-	484,529	484,529	-
597	WYU	79,500	-	84,995	84,995	-
598	CA	25,088	-	26,822	26,822	-
598	IDU	14,245	-	15,230	15,230	-
598	OR	125,086	125,086	133,732	-	133,732
598	SNPD	1,001,025	284,278	1,070,215	766,288	303,927
598	UT	108,083	-	115,554	115,554	-
598	WA	60,282	-	64,448	64,448	-
598	WYP	8,349	-	8,927	8,927	-
598	WYU	8,029	-	8,584	8,584	-
901	CA	(990)	-	(1,059)	(1,059)	-
901	CN	1,571,191	486,567	1,679,791	1,159,593	520,199
901	IDU	11,955	-	12,781	12,781	-
901	OR	(822,692)	(822,692)	(879,556)	-	(879,556)
901	UT	(5,071)	-	(5,422)	(5,422)	-
901	WA	(177,262)	-	(189,515)	(189,515)	-
901	WYP	(79,191)	-	(84,664)	(84,664)	-
901	WYU	(16,550)	-	(17,694)	(17,694)	-
902	CA	692,132	-	739,972	739,972	-
902	CN	579,080	179,330	619,106	427,381	191,725
902	IDU	1,306,878	-	1,397,209	1,397,209	-
902	OR	7,981,889	7,981,889	8,533,594	-	8,533,594
902	UT	7,663,377	-	8,193,066	8,193,066	-
902	WA	1,873,616	-	2,003,119	2,003,119	-
902	WYP	1,880,288	-	2,010,252	2,010,252	-
902	WYU	266,573	-	284,999	284,999	-
903	CA	169,894	-	181,637	181,637	-
903	CN	31,869,512	9,869,368	34,072,316	23,520,783	10,551,534
903	IDU	180,534	-	193,012	193,012	-
903	OR	1,610,254	1,610,254	1,721,554	-	1,721,554
903	UT	1,975,282	-	2,111,812	2,111,812	-
903	WA	359,711	-	384,575	384,575	-
903	WYP	204,749	-	218,901	218,901	-
903	WYU	44,509	-	47,585	47,585	-
905	CN	164,647	50,988	176,027	121,515	54,512
907	CN	249,833	77,368	267,101	184,385	82,716
908	CA	3,232	-	3,456	3,456	-
908	CN	3,061,051	947,948	3,272,629	2,259,159	1,013,469
908	IDU	357,705	-	382,429	382,429	-
908	OR	1,054,533	1,054,533	1,127,422	-	1,127,422
908	OTHER	25,327	-	27,078	27,078	-
908	UT	836,681	-	894,512	894,512	-
908	WA	-	-	-	-	-
908	WYP	660,775	-	706,447	706,447	-
909	CN	425,558	131,787	454,972	314,076	140,896
910	CN	-	-	-	-	-
920	IDU	305,097	-	326,185	326,185	-
920	SO	80,258,254	22,678,220	85,805,664	61,559,937	24,245,727
920	WA	637,047	-	681,080	681,080	-
920	WYP	1,325,743	-	1,417,377	1,417,377	-
921	SO	5,867	1,658	6,273	4,500	1,772
922	SO	(774,721)	(218,910)	(828,269)	(594,229)	(234,040)
923	SO	-	-	-	-	-
929	SO	(564,995)	(159,648)	(604,047)	(433,364)	(170,683)
935	OR	26,578	26,578	28,415	-	28,415
935	SO	4,118,853	1,163,846	4,403,546	3,159,256	1,244,291
Capitalized and Nonutility		196,969,466		210,583,898		
Total		689,915,360		737,601,966		

UE-210/PacifiCorp
July 2, 2009
ICNU 9th Set Data Request 9.33

ICNU Data Request 9.33

Provide the following information for Pacific Power Oregon by month for January through May 2009:

a. Total wages and salaries
b. Total wages and salaries charged to accounts 500 through 932
c. Total wages and salaries charged to capital or other balance sheet accounts
d. Total regular wages and salaries
e. Total overtime wages and salaries.

Response to ICNU Data Request 9.33

Please refer to Attachment ICNU 9.33. PacifiCorp uses FERC 707 as a labor clearing account. The total salary and wages are booked to FERC 707 and allocated out to the various other FERC accounts using labor allocations from time entry. The response provided shows only the total wages and salaries booked and excludes all labor allocation activity since this is considered secondary labor. FERC 707 has a zero balance on a consolidated basis.

Please refer to non-confidential Attachment ICNU 9.33 on the enclosed CD.

Total Wages and Salaries
January through May 2009

			TOTAL PACIFICORP						OREGON ALLOCATED				
			(d)	(e)			(a)		(d)	(e)			(a)
FERC Acct	FERC Acct Description	Locatn	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries	Factor	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries
4160000	COSTS & EXP OF MERCH, JOBBING, CONTRACT	110		409.02			409.02	NUTIL	-	-	-	-	-
4160000	COSTS & EXP OF MERCH, JOBBING, CONTRACT	5003	(524.40)	-			(524.40)	NUTIL	-	-	-	-	-
4160000	COSTS & EXP OF MERCH, JOBBING, CONTRACT	5402		219.00			219.00	NUTIL	-	-	-	-	-
4160000	COSTS & EXP OF MERCH, JOBBING, CONTRACT	5501		17.00			17.00	NUTIL	-	-	-	-	-
4160000	COSTS & EXP OF MERCH, JOBBING, CONTRACT	5503		323.01			323.01	NUTIL	-	-	-	-	-
4160000	COSTS & EXP OF MERCH, JOBBING, CONTRACT	122000		332.93			332.93	NUTIL	-	-	-	-	-
4160000	COSTS & EXP OF MERCH, JOBBING, CONTRACT	240000		195.64			195.64	NUTIL	-	-	-	-	-
4160000	COSTS & EXP OF MERCH, JOBBING, CONTRACT	246000		23.13			23.13	NUTIL	-	-	-	-	-
4160000	COSTS & EXP OF MERCH, JOBBING, CONTRACT	656100		188.95			188.95	NUTIL	-	-	-	-	-
4264000	EXPEN CERT CIVIC POLIT & RELTD ACTIV	106		-		264.71	264.71	NUTIL	-	-	-	-	-
4264000	EXPEN CERT CIVIC POLIT & RELTD ACTIV	107		-		264.71	264.71	NUTIL	-	-	-	-	-
4264000	EXPEN CERT CIVIC POLIT & RELTD ACTIV	108		-		1,831.46	1,831.46	NUTIL	-	-	-	-	-
4264000	EXPEN CERT CIVIC POLIT & RELTD ACTIV	109		-		2,117.68	2,117.68	NUTIL	-	-	-	-	-
4265000	OTHER DEDUCTIONS	1	24,249.77	-			24,249.77	NUTIL	-	-	-	-	-
4265000	OTHER DEDUCTIONS	517000		-		727.20	727.20	NUTIL	-	-	-	-	-
5000000	OPERATION SUPERVISION AND ENGINEERING	517000		4,572.76	33,800.00	1,560.00	39,932.76	SG	-	1,229.02	9,084.39	419.28	10,732.68
5012000	FUEL HANDLING COSTS - COAL	1	165,893.62	-		28,090.00	193,983.62	SE	41,476.55	-	-	7,023.03	48,499.59
5012000	FUEL HANDLING COSTS - COAL	514000	(303.17)	-			(303.17)	SE	(75.80)	-	-	-	(75.80)
5012000	FUEL HANDLING COSTS - COAL	517000		(19.29)	(62.22)		(81.51)	SE	-	(4.82)	(15.56)	-	(20.38)
5020000	STEAM EXPENSES	382		3,324.12			3,324.12	SG	-	893.42	-	-	893.42
5020000	STEAM EXPENSES	385	104,719.75	17,064.88		4,154.15	125,938.78	SG	28,145.41	4,586.51	-	1,116.51	33,848.42
5020000	STEAM EXPENSES	514004	(1,554.03)	-			(1,554.03)	SG	(417.67)	-	-	-	(417.67)
5020000	STEAM EXPENSES	517000		2,163.87			2,163.87	SG	-	581.58	-	-	581.58
5030000	STEAM FROM OTHER SOURCES	381		261.53			261.53	SE	-	65.39	-	-	65.39
5030000	STEAM FROM OTHER SOURCES	385		269.94			269.94	SE	-	67.49	-	-	67.49
5060000	MISCELLANEOUS STEAM POWER EXPENSES	250	2,136,154.98	389,425.83	121,521.63	105,930.31	2,753,032.75	SG	574,131.90	104,665.53	32,661.23	28,470.77	739,929.42
5060000	MISCELLANEOUS STEAM POWER EXPENSES	260	1,284,737.93	276,724.21	3,100.00	32,645.43	1,597,207.57	SG	345,297.52	74,374.85	833.18	8,774.07	429,279.63
5060000	MISCELLANEOUS STEAM POWER EXPENSES	270	4,377,580.54	1,224,171.64	13,478.02	226,865.78	5,842,095.98	SG	1,176,557.25	329,019.19	3,622.47	60,974.45	1,570,173.37
5060000	MISCELLANEOUS STEAM POWER EXPENSES	280	4,845,009.58	985,423.77	22,267.32	203,666.18	6,056,366.85	SG	1,302,187.61	264,851.20	5,984.76	54,739.12	1,627,762.70
5060000	MISCELLANEOUS STEAM POWER EXPENSES	300	6,292,801.61	911,568.75	9,110.84	258,127.25	7,471,608.45	SG	1,691,309.00	245,001.28	2,448.71	69,376.56	2,008,135.54
5060000	MISCELLANEOUS STEAM POWER EXPENSES	380	548,521.95	106,065.22	2,200.00	17,916.65	674,703.82	SG	147,425.61	28,507.03	591.29	4,815.44	181,339.36
5060000	MISCELLANEOUS STEAM POWER EXPENSES	381		1,250.41			1,250.41	SG	-	336.07	-	-	336.07
5060000	MISCELLANEOUS STEAM POWER EXPENSES	382		0.97			0.97	SG	-	0.26	-	-	0.26
5060000	MISCELLANEOUS STEAM POWER EXPENSES	514000	5,576,022.03	2,527,644.62	93,711.95	211,533.55	8,408,912.15	SG	1,498,660.98	679,352.12	25,186.85	56,853.63	2,260,053.57
5060000	MISCELLANEOUS STEAM POWER EXPENSES	514004	(28,067.45)	-			(28,067.45)	SG	(7,543.66)	-	-	-	(7,543.66)
5060000	MISCELLANEOUS STEAM POWER EXPENSES	517000	9,767,292.57	3,085,652.13	30,714.47	399,627.23	13,283,286.40	SG	2,625,143.91	829,327.15	8,255.09	107,407.35	3,570,133.49
5060000	MISCELLANEOUS STEAM POWER EXPENSES	519000	2,081,609.66	431,302.19	25,139.70	80,721.34	2,618,772.89	SG	559,471.82	115,920.59	6,756.77	21,695.38	703,844.55
5061100	MISC STEAM EXP - PLANT CLEANUP	517000		34.22	428.35		462.57	SG	-	9.20	115.13	-	124.32
5061300	MISC STEAM EXP - COMPUTER EXP	517003		36.00			36.00	SG	-	9.68	-	-	9.68
5061300	MISC STEAM EXP - COMPUTER EXP	517004		9.00			9.00	SG	-	2.42	-	-	2.42
5063000	MISC STEAM POWER EXPENSES - JVA CUTBACK CREDIT	300	(1,044,151.20)	(187,622.21)	(11,768.27)	(49,547.59)	(1,293,089.27)	SG	(280,635.31)	(50,427.00)	(3,162.94)	(13,316.85)	(347,542.10)
5063000	MISC STEAM POWER EXPENSES - JVA CUTBACK CREDIT	301		(4.38)			(4.38)	SG	-	(1.18)	-	-	(1.18)
5063000	MISC STEAM POWER EXPENSES - JVA CUTBACK CREDIT	302		(20.24)			(20.24)	SG	-	(5.44)	-	-	(5.44)
5063000	MISC STEAM POWER EXPENSES - JVA CUTBACK CREDIT	517000	(3,255,764.16)	(1,032,020.06)	(22,017.08)	(171,474.66)	(4,481,275.96)	SG	(875,047.96)	(277,374.84)	(5,917.51)	(46,087.05)	(1,204,427.35)
5063000	MISC STEAM POWER EXPENSES - JVA CUTBACK CREDIT	517001		(957.39)	(540.22)		(1,497.61)	SG	-	(257.32)	(145.19)	-	(402.51)
5063000	MISC STEAM POWER EXPENSES - JVA CUTBACK CREDIT	517002		(391.02)	(870.86)		(1,261.88)	SG	-	(105.09)	(234.06)	-	(339.15)
5063000	MISC STEAM POWER EXPENSES - JVA CUTBACK CREDIT	517003		(407.89)	(524.25)		(932.14)	SG	-	(109.63)	(140.90)	-	(250.53)
5063000	MISC STEAM POWER EXPENSES - JVA CUTBACK CREDIT	517004		(506.76)	(517.12)		(1,023.88)	SG	-	(136.20)	(138.99)	-	(275.19)
5063000	MISC STEAM POWER EXPENSES - JVA CUTBACK CREDIT	519000	(416,321.93)	(86,273.85)	(5,027.93)	(20,192.26)	(527,815.97)	SG	(111,894.36)	(23,187.72)	(1,351.35)	(5,427.05)	(141,860.49)
5064000	MISC STEAM EXP - RECRUIT / STAFF	381		199.78			199.78	SG	-	53.69	-	-	53.69
5066000	MISC STEAM EXP - SAFETY	270		-	17,750.00		17,750.00	SG	-	-	4,770.65	-	4,770.65
5066000	MISC STEAM EXP - SAFETY	300		-	49,800.00		49,800.00	SG	-	-	13,384.69	-	13,384.69
5067000	MISC STEAM EXP - TRAINING	270		102.44			102.44	SG	-	27.53	-	-	27.53
5067000	MISC STEAM EXP - TRAINING	517000		2,385.82	321.62		2,707.44	SG	-	641.23	86.44	-	727.68
5069000	MISC STEAM EXP - WATER SUPPLY	280		65.87			65.87	SG	-	17.70	-	-	17.70
5069900	MISC STEAM EXP - MISCELLANEOUS	382		886.79			886.79	SG	-	238.34	-	-	238.34
5069900	MISC STEAM EXP - MISCELLANEOUS	514000	(68.57)	-			(68.57)	SG	(18.43)	-	-	-	(18.43)
5111000	MAINT OF STRUCTURES BOILER & STRUCTURES	260		1.50			1.50	SG	-	0.40	-	-	0.40
5111000	MAINT OF STRUCTURES BOILER & STRUCTURES	261		112.47			112.47	SG	-	30.23	-	-	30.23
5111000	MAINT OF STRUCTURES BOILER & STRUCTURES	262		31.00			31.00	SG	-	8.33	-	-	8.33
5111000	MAINT OF STRUCTURES BOILER & STRUCTURES	517001		-	35.70		35.70	SG	-	-	9.60	-	9.60
5111100	MAINT OF STRUCT-WATER SUPPLY-PUMP PLANT	517000		491.94			491.94	SG	-	132.22	-	-	132.22
5111200	MAINT OF STRUCTURES - WASTE WATER	260		23.00			23.00	SG	-	6.18	-	-	6.18
5111200	MAINT OF STRUCTURES - WASTE WATER	517000		40.00			40.00	SG	-	10.75	-	-	10.75
5112000	MAINT OF STRUCTURES - BUILDINGS	517000		56.13	97.46		153.59	SG	-	15.09	26.19	-	41.28
5118000	MAINT OF STRUCTURES - GROUNDS	517000		1,229.37			1,229.37	SG	-	330.42	-	-	330.42
5119000	MAINT OF STRUCTURES - HVAC	281		31.23			31.23	SG	-	8.39	-	-	8.39

FERC Acct	FERC Acct Description	Locatn	TOTAL PACIFICORP (d) Regular Wages & Salaries	(e) Total Overtime	Other Salary Expense	Bonus/Incentive	(a) Total Wages & Salaries	Factor	OREGON ALLOCATED (d) Regular Wages & Salaries	(e) Total Overtime	Other Salary Expense	Bonus/Incentive	(a) Total Wages & Salaries
5119000	MAINT OF STRUCTURES - HVAC	517000		80.37			80.37	SG	-	21.60	-	-	21.60
5119000	MAINT OF STRUCTURES - HVAC	517001		-	57.12		57.12	SG	-	-	15.35	-	15.35
5119000	MAINT OF STRUCTURES - HVAC	517002		-	110.68		110.68	SG	-	-	29.75	-	29.75
5119000	MAINT OF STRUCTURES - HVAC	517004		-	83.07		83.07	SG	-	-	22.33	-	22.33
5121000	MAINT OF BOILER - AIR HEATER	251		11.48			11.48	SG	-	3.09	-	-	3.09
5121000	MAINT OF BOILER - AIR HEATER	270		20.96			20.96	SG	-	5.63	-	-	5.63
5121000	MAINT OF BOILER - AIR HEATER	271		166.00			166.00	SG	-	44.62	-	-	44.62
5121000	MAINT OF BOILER - AIR HEATER	517001		883.79	78.54		962.33	SG	-	237.54	21.11	-	258.64
5121000	MAINT OF BOILER - AIR HEATER	517002		42.50	380.66		423.16	SG	-	11.42	102.31	-	113.73
5121000	MAINT OF BOILER - AIR HEATER	517003		9.00	10.72		19.72	SG	-	2.42	2.88	-	5.30
5121000	MAINT OF BOILER - AIR HEATER	517004		130.16	124.96		255.12	SG	-	34.98	33.59	-	68.57
5121200	MAINT OF BOILER - COAL HANDLING	280		61.53			61.53	SG	-	16.54	-	-	16.54
5121200	MAINT OF BOILER - COAL HANDLING	517000		268.50	93.87		362.37	SG	-	72.16	25.23	-	97.39
5121200	MAINT OF BOILER - COAL HANDLING	517003		-	133.02		133.02	SG	-	-	35.75	-	35.75
5121400	MAINT OF BOILER - DEMINERALIZER	517000		-	78.56		78.56	SG	-	-	21.11	-	21.11
5121700	MAINT OF BOILER - FUEL OIL SYSTEM	517000		55.46	212.12		267.58	SG	-	14.91	57.01	-	71.92
5121700	MAINT OF BOILER - FUEL OIL SYSTEM	517001		-	57.12		57.12	SG	-	-	15.35	-	15.35
5121700	MAINT OF BOILER - FUEL OIL SYSTEM	517002		-	28.56		28.56	SG	-	-	7.68	-	7.68
5121700	MAINT OF BOILER - FUEL OIL SYSTEM	517004		-	28.56		28.56	SG	-	-	7.68	-	7.68
5121800	MAINT OF BOILER - FEEDWATER SYSTEM	251		48.60			48.60	SG	-	13.06	-	-	13.06
5121800	MAINT OF BOILER - FEEDWATER SYSTEM	261		(9.25)			(9.25)	SG	-	(2.49)	-	-	(2.49)
5121800	MAINT OF BOILER - FEEDWATER SYSTEM	262		39.20			39.20	SG	-	10.54	-	-	10.54
5121800	MAINT OF BOILER - FEEDWATER SYSTEM	263		42.50			42.50	SG	-	11.42	-	-	11.42
5121800	MAINT OF BOILER - FEEDWATER SYSTEM	273		589.26			589.26	SG	-	158.37	-	-	158.37
5121800	MAINT OF BOILER - FEEDWATER SYSTEM	517001		62.00	134.84		196.84	SG	-	16.66	36.24	-	52.90
5121800	MAINT OF BOILER - FEEDWATER SYSTEM	517002		17.00	314.24		331.24	SG	-	4.57	84.46	-	89.03
5121800	MAINT OF BOILER - FEEDWATER SYSTEM	517003		49.00	264.23		313.23	SG	-	13.17	71.02	-	84.19
5121800	MAINT OF BOILER - FEEDWATER SYSTEM	517004		31.00	67.84		98.84	SG	-	8.33	18.23	-	26.57
5121900	MAINT OF BOILER - FREEZE PROTECTION	260		(0.52)			(0.52)	SG	-	(0.14)	-	-	(0.14)
5122000	MAINT OF BOILER - AUXILIARY SYSTEM	251		79.52			79.52	SG	-	21.37	-	-	21.37
5122000	MAINT OF BOILER - AUXILIARY SYSTEM	263		114.40			114.40	SG	-	30.75	-	-	30.75
5122100	MAINT OF BOILER - MAIN STEAM	251		113.98			113.98	SG	-	30.63	-	-	30.63
5122100	MAINT OF BOILER - MAIN STEAM	263		2.63			2.63	SG	-	0.71	-	-	0.71
5122100	MAINT OF BOILER - MAIN STEAM	272		44.36			44.36	SG	-	11.92	-	-	11.92
5122100	MAINT OF BOILER - MAIN STEAM	273		513.75			513.75	SG	-	138.08	-	-	138.08
5122100	MAINT OF BOILER - MAIN STEAM	282		20.98			20.98	SG	-	5.64	-	-	5.64
5122100	MAINT OF BOILER - MAIN STEAM	381		170.92			170.92	SG	-	45.94	-	-	45.94
5122100	MAINT OF BOILER - MAIN STEAM	517001		-	22.92		22.92	SG	-	-	6.16	-	6.16
5122100	MAINT OF BOILER - MAIN STEAM	517003		-	39.16		39.16	SG	-	-	10.52	-	10.52
5122100	MAINT OF BOILER - MAIN STEAM	517004		-	145.16		145.16	SG	-	-	39.01	-	39.01
5122100	MAINT OF BOILER - MAIN STEAM	519000		31.00			31.00	SG	-	8.33	-	-	8.33
5122200	MAINT OF BOILER - PULVERIZED COAL	281		(14.68)			(14.68)	SG	-	(3.95)	-	-	(3.95)
5122200	MAINT OF BOILER - PULVERIZED COAL	514001	(4,345.37)	-			(4,345.37)	SG	(1,167.90)	-	-	-	(1,167.90)
5122200	MAINT OF BOILER - PULVERIZED COAL	514002	(27,600.65)	-			(27,600.65)	SG	(7,418.19)	-	-	-	(7,418.19)
5122200	MAINT OF BOILER - PULVERIZED COAL	514004		15.50			15.50	SG	-	4.17	-	-	4.17
5122200	MAINT OF BOILER - PULVERIZED COAL	517001		-	121.01		121.01	SG	-	-	32.52	-	32.52
5122200	MAINT OF BOILER - PULVERIZED COAL	517002		107.12	100.58		207.70	SG	-	28.79	27.03	-	55.82
5122200	MAINT OF BOILER - PULVERIZED COAL	517003		77.50	30.56		108.06	SG	-	20.83	8.21	-	29.04
5122200	MAINT OF BOILER - PULVERIZED COAL	517004		9.00	152.13		161.13	SG	-	2.42	40.89	-	43.31
5122300	MAINT OF BOILER - PRECIPITATOR	517003		18.00			18.00	SG	-	4.84	-	-	4.84
5122400	MAINT OF BOILER - PRETREATMENT WATER	260		174.50			174.50	SG	-	46.90	-	-	46.90
5122400	MAINT OF BOILER - PRETREATMENT WATER	517000		-	85.68		85.68	SG	-	-	23.03	-	23.03
5122500	MAINT OF BOILER - REVERSE OSMOSIS	517000		-	159.10		159.10	SG	-	-	42.76	-	42.76
5122600	MAINT OF BOILER - REHEAT STEAM	263		3.71			3.71	SG	-	1.00	-	-	1.00
5122600	MAINT OF BOILER - REHEAT STEAM	273		59.64			59.64	SG	-	16.03	-	-	16.03
5122600	MAINT OF BOILER - REHEAT STEAM	281		(4.03)			(4.03)	SG	-	(1.08)	-	-	(1.08)
5122800	MAINT OF BOILER - SOOTBLOWING	251		71.42			71.42	SG	-	19.20	-	-	19.20
5122800	MAINT OF BOILER - SOOTBLOWING	272		4.00			4.00	SG	-	1.08	-	-	1.08
5122800	MAINT OF BOILER - SOOTBLOWING	517001		155.71	162.65		318.36	SG	-	41.85	43.72	-	85.57
5122800	MAINT OF BOILER - SOOTBLOWING	517003		64.50	214.06		278.56	SG	-	17.34	57.53	-	74.87
5122800	MAINT OF BOILER - SOOTBLOWING	517004		421.05	376.31		797.36	SG	-	113.17	101.14	-	214.31
5122900	MAINT OF BOILER - SCRUBBER	273		9.00			9.00	SG	-	2.42	-	-	2.42
5122900	MAINT OF BOILER - SCRUBBER	302		-			-	SG	-	-	-	-	-
5122900	MAINT OF BOILER - SCRUBBER	517001		24.50	28.56		53.06	SG	-	6.58	7.68	-	14.26
5122900	MAINT OF BOILER - SCRUBBER	517004		24.50			24.50	SG	-	6.58	-	-	6.58
5123000	MAINT OF BOILER - BOTTOM ASH	281		19.13			19.13	SG	-	5.14	-	-	5.14
5123000	MAINT OF BOILER - BOTTOM ASH	282		21.25			21.25	SG	-	5.71	-	-	5.71
5123000	MAINT OF BOILER - BOTTOM ASH	517000		9.00	92.82		101.82	SG	-	2.42	24.95	-	27.37
5123000	MAINT OF BOILER - BOTTOM ASH	517001		328.88	150.00		478.88	SG	-	88.39	40.32	-	128.71
5123000	MAINT OF BOILER - BOTTOM ASH	517002		-	10.72		10.72	SG	-	-	2.88	-	2.88
5123000	MAINT OF BOILER - BOTTOM ASH	517003		82.06	402.25		484.31	SG	-	22.06	108.11	-	130.17
5123000	MAINT OF BOILER - BOTTOM ASH	517004		-	167.80		167.80	SG	-	-	45.10	-	45.10

FERC Acct	FERC Acct Description	Locatn	TOTAL PACIFICORP (d) Regular Wages & Salaries	(e) Total Overtime	Other Salary Expense	Bonus/Incentive	(a) Total Wages & Salaries	Factor	OREGON ALLOCATED (d) Regular Wages & Salaries	(e) Total Overtime	Other Salary Expense	Bonus/Incentive	(a) Total Wages & Salaries
5123100	MAINT OF BOILER - WATER TREATMENT	262		19.75			19.75	SG	-	5.31	-	-	5.31
5123200	MAINT OF BOILER - CENTRAL SUPPORT	260		114.71			114.71	SG	-	30.83	-	-	30.83
5123200	MAINT OF BOILER - CENTRAL SUPPORT	517000		69.50	78.54		148.04	SG	-	18.68	21.11	-	39.79
5123300	MAINTENANCE OF GEOTHERMAL GATHERING SYS	381		1,910.35			1,910.35	SG	-	513.44	-	-	513.44
5123300	MAINTENANCE OF GEOTHERMAL GATHERING SYS	385		42.22			42.22	SG	-	11.35	-	-	11.35
5123400	MAINT OF BOILERS-CONTINUOUS EMISS MONITR	260		97.24			97.24	SG	-	26.14	-	-	26.14
5123400	MAINT OF BOILERS-CONTINUOUS EMISS MONITR	261		20.40			20.40	SG	-	5.48	-	-	5.48
5123400	MAINT OF BOILERS-CONTINUOUS EMISS MONITR	262		22.84			22.84	SG	-	6.14	-	-	6.14
5123400	MAINT OF BOILERS-CONTINUOUS EMISS MONITR	263		14.99			14.99	SG	-	4.03	-	-	4.03
5123400	MAINT OF BOILERS-CONTINUOUS EMISS MONITR	517000		49.00			49.00	SG	-	13.17	-	-	13.17
5123400	MAINT OF BOILERS-CONTINUOUS EMISS MONITR	517002		15.50			15.50	SG	-	4.17	-	-	4.17
5123400	MAINT OF BOILERS-CONTINUOUS EMISS MONITR	517003		128.42			128.42	SG	-	34.52	-	-	34.52
5123400	MAINT OF BOILERS-CONTINUOUS EMISS MONITR	517004		(5.64)			(5.64)	SG	-	(1.52)	-	-	(1.52)
5124000	MAINT OF BOILER - BOILER CONTROLS	517001		40.00	112.46		152.46	SG	-	10.75	30.23	-	40.98
5124000	MAINT OF BOILER - BOILER CONTROLS	517004		24.50	49.98		74.48	SG	-	6.58	13.43	-	20.02
5125000	MAINT OF BOILER - BOILER DRAFT	262		123.92			123.92	SG	-	33.31	-	-	33.31
5125000	MAINT OF BOILER - BOILER DRAFT	263		3.00			3.00	SG	-	0.81	-	-	0.81
5125000	MAINT OF BOILER - BOILER DRAFT	517001		84.78	192.79		277.57	SG	-	22.79	51.82	-	74.60
5125000	MAINT OF BOILER - BOILER DRAFT	517002		-	157.11		157.11	SG	-	-	42.23	-	42.23
5125000	MAINT OF BOILER - BOILER DRAFT	517003		-	114.24		114.24	SG	-	-	30.70	-	30.70
5125000	MAINT OF BOILER - BOILER DRAFT	517004		-	28.56		28.56	SG	-	-	7.68	-	7.68
5126000	MAINT OF BOILER - BOILER FIRESIDE	263		84.31			84.31	SG	-	22.66	-	-	22.66
5126000	MAINT OF BOILER - BOILER FIRESIDE	517003		-	57.12		57.12	SG	-	-	15.35	-	15.35
5128000	MAINT OF BOILER - BOILER WATER/STEAMSIDE	251		96.22			96.22	SG	-	25.86	-	-	25.86
5128000	MAINT OF BOILER - BOILER WATER/STEAMSIDE	262		46.00			46.00	SG	-	12.36	-	-	12.36
5128000	MAINT OF BOILER - BOILER WATER/STEAMSIDE	263		26.00			26.00	SG	-	6.99	-	-	6.99
5128000	MAINT OF BOILER - BOILER WATER/STEAMSIDE	281		(5.92)			(5.92)	SG	-	(1.59)	-	-	(1.59)
5128000	MAINT OF BOILER - BOILER WATER/STEAMSIDE	282		105.07			105.07	SG	-	28.24	-	-	28.24
5128000	MAINT OF BOILER - BOILER WATER/STEAMSIDE	517001		286.50	198.84		485.34	SG	-	77.00	53.44	-	130.44
5128000	MAINT OF BOILER - BOILER WATER/STEAMSIDE	517002		141.23	578.09		719.32	SG	-	37.96	155.37	-	193.33
5128000	MAINT OF BOILER - BOILER WATER/STEAMSIDE	517004		124.00	71.40		195.40	SG	-	33.33	19.19	-	52.52
5129900	MAINTENANCE OF BOILER - MISCELLANEOUS	281		21.25			21.25	SG	-	5.71	-	-	5.71
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	250		21.00			21.00	SG	-	5.64	-	-	5.64
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	251		230.96			230.96	SG	-	62.07	-	-	62.07
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	252		24.00			24.00	SG	-	6.45	-	-	6.45
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	261		46.96			46.96	SG	-	12.62	-	-	12.62
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	262		(45.30)			(45.30)	SG	-	(12.18)	-	-	(12.18)
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	263		55.07			55.07	SG	-	14.80	-	-	14.80
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	280		229.00			229.00	SG	-	61.55	-	-	61.55
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	281		115.00			115.00	SG	-	30.91	-	-	30.91
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	282		172.05			172.05	SG	-	46.24	-	-	46.24
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	301		53.23			53.23	SG	-	14.31	-	-	14.31
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	302		51.00			51.00	SG	-	13.71	-	-	13.71
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	303		52.64			52.64	SG	-	14.15	-	-	14.15
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	381		434.24			434.24	SG	-	116.71	-	-	116.71
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	382		150.86			150.86	SG	-	40.55	-	-	40.55
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	514004		930.03			930.03	SG	-	249.96	-	-	249.96
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	517000		3,483.68			3,483.68	SG	-	936.30	-	-	936.30
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	517001		497.42	96.39		593.81	SG	-	133.69	25.91	-	159.60
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	517002		7.95	143.12		151.07	SG	-	2.14	38.47	-	40.60
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	517004		126.50	28.56		155.06	SG	-	34.00	7.68	-	41.68
5131000	MAINT OF ELECT PLANT - ELECTRICAL - AC	519000		36.17			36.17	SG	-	9.72	-	-	9.72
5131100	MAINT OF ELEC PLANT - LUBE OIL SYSTEM	263		228.99			228.99	SG	-	61.55	-	-	61.55
5131100	MAINT OF ELEC PLANT - LUBE OIL SYSTEM	381		187.47			187.47	SG	-	50.39	-	-	50.39
5131100	MAINT OF ELEC PLANT - LUBE OIL SYSTEM	517001		-	57.12		57.12	SG	-	-	15.35	-	15.35
5131100	MAINT OF ELEC PLANT - LUBE OIL SYSTEM	517002		-	(31.17)		(31.17)	SG	-	-	(8.38)	-	(8.38)
5131100	MAINT OF ELEC PLANT - LUBE OIL SYSTEM	517003		-	(10.39)		(10.39)	SG	-	-	(2.79)	-	(2.79)
5131100	MAINT OF ELEC PLANT - LUBE OIL SYSTEM	517004		-	(10.39)		(10.39)	SG	-	-	(2.79)	-	(2.79)
5131400	MAINT OF ELEC PLANT - MAIN TURBINE	261		119.12			119.12	SG	-	32.02	-	-	32.02
5131400	MAINT OF ELEC PLANT - MAIN TURBINE	262		75.42			75.42	SG	-	20.27	-	-	20.27
5131400	MAINT OF ELEC PLANT - MAIN TURBINE	263		56.84			56.84	SG	-	15.28	-	-	15.28
5131400	MAINT OF ELEC PLANT - MAIN TURBINE	281	(1,300.00)	(1,300.00)			(2,600.00)	SG	(349.40)	(349.40)	-	-	(698.80)
5131400	MAINT OF ELEC PLANT - MAIN TURBINE	301		17.00			17.00	SG	-	4.57	-	-	4.57
5131400	MAINT OF ELEC PLANT - MAIN TURBINE	381		292.90			292.90	SG	-	78.72	-	-	78.72
5131400	MAINT OF ELEC PLANT - MAIN TURBINE	514003	(17,415.27)	-			(17,415.27)	SG	(4,680.68)	-	-	-	(4,680.68)
5131400	MAINT OF ELEC PLANT - MAIN TURBINE	517001		124.00			124.00	SG	-	33.33	-	-	33.33
5131400	MAINT OF ELEC PLANT - MAIN TURBINE	517002		-	133.30		133.30	SG	-	-	35.83	-	35.83
5131400	MAINT OF ELEC PLANT - MAIN TURBINE	517003		40.00	146.42		186.42	SG	-	10.75	39.35	-	50.10
5131400	MAINT OF ELEC PLANT - MAIN TURBINE	517004		-	94.61		94.61	SG	-	-	25.43	-	25.43
5132000	MAINT OF ELEC PLNT-ALARMS/INFO HANDLING	251		51.00			51.00	SG	-	13.71	-	-	13.71
5132000	MAINT OF ELEC PLNT-ALARMS/INFO HANDLING	260		108.05			108.05	SG	-	29.04	-	-	29.04
5135000	MAINT OF ELEC PLANT - COMPONENT/AUXIL	263		6.00			6.00	SG	-	1.61	-	-	1.61

			TOTAL PACIFICORP						OREGON ALLOCATED				
			(d)	(e)			(a)		(d)	(e)			(a)
FERC Acct	FERC Acct Description	Locatn	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries	Factor	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries
5135000	MAINT OF ELEC PLANT - COMPONENT/AUXIL	381		27.60			27.60	SG	-	7.42	-	-	7.42
5135000	MAINT OF ELEC PLANT - COMPONENT/AUXIL	517001		-	28.89		28.89	SG	-	-	7.76	-	7.76
5135000	MAINT OF ELEC PLANT - COMPONENT/AUXIL	517003		-	28.56		28.56	SG	-	-	7.68	-	7.68
5137000	MAINT OF ELEC PLANT - COOLING TOWER	263		102.91			102.91	SG	-	27.66	-	-	27.66
5137000	MAINT OF ELEC PLANT - COOLING TOWER	514000	(1,671.26)	-			(1,671.26)	SG	(449.18)	-	-	-	(449.18)
5137000	MAINT OF ELEC PLANT - COOLING TOWER	517001		-	85.68		85.68	SG	-	-	23.03	-	23.03
5137000	MAINT OF ELEC PLANT - COOLING TOWER	517002		-	615.29		615.29	SG	-	-	165.37	-	165.37
5137000	MAINT OF ELEC PLANT - COOLING TOWER	517003		-	85.68		85.68	SG	-	-	23.03	-	23.03
5137000	MAINT OF ELEC PLANT - COOLING TOWER	517004		-	28.56		28.56	SG	-	-	7.68	-	7.68
5138000	MAINT OF ELEC PLANT - CIRCULATING WATER	262		120.34			120.34	SG	-	32.34	-	-	32.34
5138000	MAINT OF ELEC PLANT - CIRCULATING WATER	263		41.67			41.67	SG	-	11.20	-	-	11.20
5138000	MAINT OF ELEC PLANT - CIRCULATING WATER	517000		65.14	18.17		83.31	SG	-	17.51	4.88	-	22.39
5138000	MAINT OF ELEC PLANT - CIRCULATING WATER	517002		-	71.47		71.47	SG	-	-	19.21	-	19.21
5138000	MAINT OF ELEC PLANT - CIRCULATING WATER	517003		108.50	57.12		165.62	SG	-	29.16	15.35	-	44.51
5138000	MAINT OF ELEC PLANT - CIRCULATING WATER	517004		15.50	114.24		129.74	SG	-	4.17	30.70	-	34.87
5139000	MAINT OF ELEC PLANT - ELECTRICAL - DC	260		5.96			5.96	SG	-	1.60	-	-	1.60
5139000	MAINT OF ELEC PLANT - ELECTRICAL - DC	262		28.88			28.88	SG	-	7.76	-	-	7.76
5139000	MAINT OF ELEC PLANT - ELECTRICAL - DC	517002		24.50			24.50	SG	-	6.58	-	-	6.58
5139900	MAINTENANCE OF ELECTRIC PLANT - MISC	381		89.92			89.92	SG	-	24.17	-	-	24.17
5140000	MAINTENANCE OF MISC STEAM PLANT	300	525,922.46	313,679.04	17,940.72		857,542.22	SG	141,351.57	84,307.15	4,821.91	-	230,480.63
5140000	MAINTENANCE OF MISC STEAM PLANT	514004	29,924.65	-			29,924.65	SG	8,042.81	-	-	-	8,042.81
5141000	MAINT OF MISC STM PLANT-COMPRESS AIR	517000		142.40	57.12		199.52	SG	-	38.27	15.35	-	53.62
5144000	MAINT OF MISC STEAM PLANT - LABORATORY	262		(3.18)			(3.18)	SG	-	(0.85)	-	-	(0.85)
5146000	MAINT OF MISC STM PLNT-PAGING SYSTEM	270		17.00			17.00	SG	-	4.57	-	-	4.57
5147000	MAINT OF MISC STM PLNT - PLANT EQUIPMENT	517000		9.86			9.86	SG	-	2.65	-	-	2.65
5148000	MAINT OF MISC STEAM PLANT - VEHICLES	517000		65.80			65.80	SG	-	17.68	-	-	17.68
5350000	OPERATION SUPERVISION AND ENGINEERING	1	1,815,901.65	7,241.34	3,364.77	405,986.39	2,232,494.15	SG-U	488,057.78	1,946.25	904.35	109,116.49	600,024.87
5350000	OPERATION SUPERVISION AND ENGINEERING	103	305,182.23	44,795.52	2,689.27		352,667.02	SG-P	82,023.47	12,039.64	722.79	-	94,785.91
5350000	OPERATION SUPERVISION AND ENGINEERING	557	577,906.21	178,891.58	2,121.28	120.47	759,039.54	SG-U	155,323.18	48,080.48	570.13	32.38	204,006.18
5350000	OPERATION SUPERVISION AND ENGINEERING	1034	785,933.00	84,452.13		29.97	870,415.10	SG-U	211,234.30	22,698.10	-	8.06	233,940.46
5350000	OPERATION SUPERVISION AND ENGINEERING	48000	691,810.57	280,863.99	14,950.29	53.55	987,678.40	SG-P	185,937.13	75,487.49	4,018.17	14.39	265,457.18
5350000	OPERATION SUPERVISION AND ENGINEERING	133070	642,402.21	101,809.43	4,366.48	35.70	748,613.82	SG-P	172,657.70	27,363.20	1,173.57	9.60	201,204.07
5350000	OPERATION SUPERVISION AND ENGINEERING	215300	1,495,368.87	222,919.26	13,870.21	7,541.97	1,739,700.31	SG-P	401,908.56	59,913.75	3,727.88	2,027.05	467,577.24
5350000	OPERATION SUPERVISION AND ENGINEERING	262000	(129,044.80)	(30,503.11)	(1,872.49)	(8.19)	(161,428.59)	SG-P	(34,683.22)	(8,198.29)	(503.27)	(2.20)	(43,386.98)
5379000	HYDRAULIC EXPENSES - OTHER	1		-	6,700.00		6,700.00	SG-U	-	-	1,800.75	-	1,800.75
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	1		83.39			83.39	SG-U	-	22.41	-	-	22.41
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	103		-	14,218.01	2,900.00	17,118.01	SG-P	-	-	3,821.36	779.43	4,600.79
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	108		-	15,688.94		15,688.94	SG-P	-	-	4,216.70	-	4,216.70
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	444		118.63			118.63	SG-U	-	31.88	-	-	31.88
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	445		159.00			159.00	SG-U	-	42.73	-	-	42.73
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	446		22.36			22.36	SG-U	-	6.01	-	-	6.01
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	448		63.97			63.97	SG-U	-	17.19	-	-	17.19
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	449		320.32			320.32	SG-U	-	86.09	-	-	86.09
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	451		67.87			67.87	SG-U	-	18.24	-	-	18.24
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	452		73.28			73.28	SG-U	-	19.70	-	-	19.70
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	454		155.46			155.46	SG-U	-	41.78	-	-	41.78
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	455		53.33			53.33	SG-U	-	14.33	-	-	14.33
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	457		382.21			382.21	SG-U	-	102.73	-	-	102.73
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	458		9.04			9.04	SG-U	-	2.43	-	-	2.43
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	459		42.32			42.32	SG-U	-	11.37	-	-	11.37
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	460		58.20			58.20	SG-U	-	15.64	-	-	15.64
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	461		17.45			17.45	SG-U	-	4.69	-	-	4.69
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	463		47.72			47.72	SG-U	-	12.83	-	-	12.83
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	464		83.92			83.92	SG-U	-	22.56	-	-	22.56
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	465		23.35			23.35	SG-U	-	6.28	-	-	6.28
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	468		36.23			36.23	SG-U	-	9.74	-	-	9.74
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	557		282.95			282.95	SG-U	-	76.05	-	-	76.05
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	1034		923.72	100.00		1,023.72	SG-U	-	248.27	26.88	-	275.14
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	18000		127.10			127.10	SG-P	-	34.16	-	-	34.16
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	29000		153.09			153.09	SG-P	-	41.15	-	-	41.15
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	31000		118.62			118.62	SG-P	-	31.88	-	-	31.88
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	32000		666.43			666.43	SG-P	-	179.12	-	-	179.12
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	33000		275.61			275.61	SG-P	-	74.08	-	-	74.08
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	36000		35.55			35.55	SG-P	-	9.55	-	-	9.55
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	40000		309.12			309.12	SG-P	-	83.08	-	-	83.08
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	41000		(26.45)			(26.45)	SG-P	-	(7.11)	-	-	(7.11)
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	42000		152.51			152.51	SG-P	-	40.99	-	-	40.99
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	44000		59.94			59.94	SG-P	-	16.11	-	-	16.11
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	46000		169.45			169.45	SG-P	-	45.54	-	-	45.54
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	48000		165.02	14,448.33	6,800.00	21,413.35	SG-P	-	44.35	3,883.26	1,827.63	5,755.24
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	133070		-	15,107.54	5,500.00	20,607.54	SG-P	-	-	4,060.44	1,478.23	5,538.66
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	610000		231.59			231.59	SG-P	-	62.24	-	-	62.24

			TOTAL PACIFICORP						OREGON ALLOCATED				
			(d)	(e)			(a)		(d)	(e)			(a)
FERC Acct	FERC Acct Description	Locatn	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries	Factor	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	611000		164.23			164.23	SG-P	-	44.14	-	-	44.14
5390000	MISC HYDRAULIC POWER GENERATION EXPENSES	612000		251.81			251.81	SG-P	-	67.68	-	-	67.68
5420000	MAINTENANCE OF STRUCTURES	41000		277.91			277.91	SG-P	-	74.69	-	-	74.69
5430000	MAINT OF RESERVOIRS, DAMS AND WATERWAYS	444		31.50			31.50	SG-U	-	8.47	-	-	8.47
5430000	MAINT OF RESERVOIRS, DAMS AND WATERWAYS	448		85.40			85.40	SG-U	-	22.95	-	-	22.95
5430000	MAINT OF RESERVOIRS, DAMS AND WATERWAYS	452		3.92			3.92	SG-U	-	1.05	-	-	1.05
5430000	MAINT OF RESERVOIRS, DAMS AND WATERWAYS	457		234.75			234.75	SG-U	-	63.09	-	-	63.09
5430000	MAINT OF RESERVOIRS, DAMS AND WATERWAYS	464		926.25			926.25	SG-U	-	248.95	-	-	248.95
5430000	MAINT OF RESERVOIRS, DAMS AND WATERWAYS	465		(54.19)			(54.19)	SG-U	-	(14.56)	-	-	(14.56)
5430000	MAINT OF RESERVOIRS, DAMS AND WATERWAYS	36000		(57.85)			(57.85)	SG-P	-	(15.55)	-	-	(15.55)
5430000	MAINT OF RESERVOIRS, DAMS AND WATERWAYS	41000		934.28			934.28	SG-P	-	251.11	-	-	251.11
5430000	MAINT OF RESERVOIRS, DAMS AND WATERWAYS	42000		64.05			64.05	SG-P	-	17.21	-	-	17.21
5430000	MAINT OF RESERVOIRS, DAMS AND WATERWAYS	45000		67.78			67.78	SG-P	-	18.22	-	-	18.22
5430000	MAINT OF RESERVOIRS, DAMS AND WATERWAYS	133070		593.41			593.41	SG-P	-	159.49	-	-	159.49
5430000	MAINT OF RESERVOIRS, DAMS AND WATERWAYS	611000		117.36			117.36	SG-P	-	31.54	-	-	31.54
5440000	MAINTENANCE OF ELECTRIC PLANT	557		81.07			81.07	SG-U	-	21.79	-	-	21.79
5441000	PRIME MOVERS & GENERATORS	444		71.53			71.53	SG-U	-	19.23	-	-	19.23
5441000	PRIME MOVERS & GENERATORS	448		22.94			22.94	SG-U	-	6.17	-	-	6.17
5441000	PRIME MOVERS & GENERATORS	449		312.38			312.38	SG-U	-	83.96	-	-	83.96
5441000	PRIME MOVERS & GENERATORS	451		85.85			85.85	SG-U	-	23.07	-	-	23.07
5441000	PRIME MOVERS & GENERATORS	454		164.29			164.29	SG-U	-	44.16	-	-	44.16
5441000	PRIME MOVERS & GENERATORS	455		477.30			477.30	SG-U	-	128.28	-	-	128.28
5441000	PRIME MOVERS & GENERATORS	459		708.47			708.47	SG-U	-	190.41	-	-	190.41
5441000	PRIME MOVERS & GENERATORS	468		-			-	SG-U	-	-	-	-	-
5441000	PRIME MOVERS & GENERATORS	18000		225.12			225.12	SG-P	-	60.51	-	-	60.51
5441000	PRIME MOVERS & GENERATORS	32000		188.95			188.95	SG-P	-	50.78	-	-	50.78
5441000	PRIME MOVERS & GENERATORS	40000		66.12			66.12	SG-P	-	17.77	-	-	17.77
5441000	PRIME MOVERS & GENERATORS	42000		132.27			132.27	SG-P	-	35.55	-	-	35.55
5441000	PRIME MOVERS & GENERATORS	44000		62.68			62.68	SG-P	-	16.85	-	-	16.85
5442000	ACCESSORY ELECTRIC EQUIPMENT	445		23.64			23.64	SG-U	-	6.35	-	-	6.35
5442000	ACCESSORY ELECTRIC EQUIPMENT	448		22.13			22.13	SG-U	-	5.95	-	-	5.95
5442000	ACCESSORY ELECTRIC EQUIPMENT	449		78.25			78.25	SG-U	-	21.03	-	-	21.03
5442000	ACCESSORY ELECTRIC EQUIPMENT	452		22.12			22.12	SG-U	-	5.95	-	-	5.95
5442000	ACCESSORY ELECTRIC EQUIPMENT	454		(7.69)			(7.69)	SG-U	-	(2.07)	-	-	(2.07)
5442000	ACCESSORY ELECTRIC EQUIPMENT	455		9.22			9.22	SG-U	-	2.48	-	-	2.48
5442000	ACCESSORY ELECTRIC EQUIPMENT	463		78.12			78.12	SG-U	-	21.00	-	-	21.00
5442000	ACCESSORY ELECTRIC EQUIPMENT	18000		(45.75)			(45.75)	SG-P	-	(12.30)	-	-	(12.30)
5442000	ACCESSORY ELECTRIC EQUIPMENT	40000		567.15			567.15	SG-P	-	152.43	-	-	152.43
5442000	ACCESSORY ELECTRIC EQUIPMENT	41000		(28.10)			(28.10)	SG-P	-	(7.55)	-	-	(7.55)
5442000	ACCESSORY ELECTRIC EQUIPMENT	42000		146.74			146.74	SG-P	-	39.44	-	-	39.44
5442000	ACCESSORY ELECTRIC EQUIPMENT	44000		160.13			160.13	SG-P	-	43.04	-	-	43.04
5442000	ACCESSORY ELECTRIC EQUIPMENT	48000		(26.44)			(26.44)	SG-P	-	(7.11)	-	-	(7.11)
5442000	ACCESSORY ELECTRIC EQUIPMENT	611000		8.27			8.27	SG-P	-	2.22	-	-	2.22
5442000	ACCESSORY ELECTRIC EQUIPMENT	612000		107.45			107.45	SG-P	-	28.88	-	-	28.88
5442000	ACCESSORY ELECTRIC EQUIPMENT	613000		36.07			36.07	SG-P	-	9.69	-	-	9.69
5455000	MAINT MISC HYDRO PLNT-ROADS/TRAILS/BRIDG	457		19.02			19.02	SG-U	-	5.11	-	-	5.11
5455000	MAINT MISC HYDRO PLNT-ROADS/TRAILS/BRIDG	48000		122.98			122.98	SG-P	-	33.05	-	-	33.05
5459000	MAINT MISC HYDRO PLANT - OTHER	455		40.84			40.84	SG-U	-	10.98	-	-	10.98
5459000	MAINT MISC HYDRO PLANT - OTHER	457		25.55			25.55	SG-U	-	6.87	-	-	6.87
5459000	MAINT MISC HYDRO PLANT - OTHER	461		(1.21)			(1.21)	SG-U	-	(0.33)	-	-	(0.33)
5459000	MAINT MISC HYDRO PLANT - OTHER	557		44.81			44.81	SG-U	-	12.04	-	-	12.04
5459000	MAINT MISC HYDRO PLANT - OTHER	1034		212.63			212.63	SG-U	-	57.15	-	-	57.15
5459000	MAINT MISC HYDRO PLANT - OTHER	48000		17.10			17.10	SG-P	-	4.60	-	-	4.60
5459000	MAINT MISC HYDRO PLANT - OTHER	133070		113.87			113.87	SG-P	-	30.60	-	-	30.60
5480000	GENERATION EXPENSES	210		-	(1.82)		(1.82)	SSGCT	-	-	(0.46)	-	(0.46)
5480000	GENERATION EXPENSES	225	313,723.36	87,200.90			400,924.26	SG	84,319.06	23,436.88	-	-	107,755.95
5480000	GENERATION EXPENSES	264		6.50	3,100.00	32,500.00	35,606.50	SSGCT	-	1.64	780.19	8,179.37	8,961.19
5480000	GENERATION EXPENSES	310	336,161.97	79,185.14			415,347.11	SG	90,349.86	21,282.50	-	-	111,632.36
5480000	GENERATION EXPENSES	475	182,590.38	23,263.52			205,853.90	SG	49,074.60	6,252.51	-	-	55,327.11
5480000	GENERATION EXPENSES	203300	276,174.51	89,979.38		53,750.00	419,903.89	SG	74,227.10	24,183.65	-	14,446.33	112,857.08
5490000	MISC OTHER POWER GENERATION EXPENSES	1	254,711.51	-		38,328.40	293,039.91	SG	68,458.52	-	-	10,301.48	78,760.00
5490000	MISC OTHER POWER GENERATION EXPENSES	225	128,176.02	70.13		30,490.85	158,737.00	SG	34,449.72	18.85	-	8,194.99	42,663.56
5490000	MISC OTHER POWER GENERATION EXPENSES	310	84,810.28	410.21	3,364.77	31,833.30	120,418.56	SG	22,794.36	110.25	904.35	8,555.80	32,364.76
5490000	MISC OTHER POWER GENERATION EXPENSES	129600		41.43			41.43	SG	-	11.14	-	-	11.14
5490000	MISC OTHER POWER GENERATION EXPENSES	203300	116,868.04	-	6,000.00	25,000.00	147,868.04	SG	31,410.49	-	1,612.61	6,719.22	39,742.32
5490000	MISC OTHER POWER GENERATION EXPENSES	205300		155.90			155.90	SG	-	41.90	-	-	41.90
5490000	MISC OTHER POWER GENERATION EXPENSES	206100		1,163.81			1,163.81	SG	-	312.80	-	-	312.80
5490000	MISC OTHER POWER GENERATION EXPENSES	506110		15.50			15.50	SG	-	4.17	-	-	4.17
5490000	MISC OTHER POWER GENERATION EXPENSES	576500		63.08			63.08	SG	-	16.95	-	-	16.95
5520000	MAINTENANCE OF STRUCTURES	227		95.34			95.34	SG	-	25.62	-	-	25.62
5520000	MAINTENANCE OF STRUCTURES	264		236.23			236.23	SSGCT	-	59.45	-	-	59.45
5530000	MAINT OF GENERATING AND ELECTRIC PLANT	225	215,888.05	35,408.79			251,296.84	SG	58,023.98	9,516.78	-	-	67,540.76

			TOTAL PACIFICORP						OREGON ALLOCATED				
			(d)	(e)			(a)		(d)	(e)			(a)
FERC Acct	FERC Acct Description	Locatn	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries	Factor	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries
5530000	MAINT OF GENERATING AND ELECTRIC PLANT	264		62.00			62.00	SSGCT	-	15.60	-	-	15.60
5530000	MAINT OF GENERATING AND ELECTRIC PLANT	265		3,236.23			3,236.23	SSGCT	-	814.47	-	-	814.47
5530000	MAINT OF GENERATING AND ELECTRIC PLANT	266		443.50			443.50	SSGCT	-	111.62	-	-	111.62
5530000	MAINT OF GENERATING AND ELECTRIC PLANT	267		384.19			384.19	SSGCT	-	96.69	-	-	96.69
5530000	MAINT OF GENERATING AND ELECTRIC PLANT	310	165,618.67	33,901.59			199,520.26	SG	44,513.14	9,111.69	-	-	53,624.83
5530000	MAINT OF GENERATING AND ELECTRIC PLANT	129600		415.27			415.27	SG	-	111.61	-	-	111.61
5530000	MAINT OF GENERATING AND ELECTRIC PLANT	203300	129,755.32	9,878.10	106.74		139,740.16	SG	34,874.19	2,654.93	28.69	-	37,557.80
5540000	MAINT OF MISC OTHER POWER GEN PLANT	265		16.28			16.28	SSGCT	-	4.10	-	-	4.10
5540000	MAINT OF MISC OTHER POWER GEN PLANT	266		66.92			66.92	SSGCT	-	16.84	-	-	16.84
5540000	MAINT OF MISC OTHER POWER GEN PLANT	267		23.40			23.40	SSGCT	-	5.89	-	-	5.89
5540000	MAINT OF MISC OTHER POWER GEN PLANT	475		49.32			49.32	SG	-	13.26	-	-	13.26
5560000	SYSTEM CONTROL AND LOAD DISPATCHING	1	361,563.06	-			361,563.06	SG	97,176.88	-	-	-	97,176.88
5570000	OTHER EXPENSES	1	9,874,932.45	59,821.34	139,440.79	2,290,583.47	12,364,778.05	SG	2,654,074.15	16,078.11	37,477.34	615,637.46	3,323,267.07
5570000	OTHER EXPENSES	906	898,088.93	6,372.41	25,026.48	165,204.24	1,094,692.06	SG	241,378.32	1,712.71	6,726.34	44,401.75	294,219.12
5600000	OPERATION SUPERVISION AND ENGINEERING	1	5,070,170.86	12,236.07	50,428.44	315,780.43	5,448,615.80	SG	1,362,703.95	3,288.67	13,553.59	84,871.94	1,464,418.15
5612000	LOAD DISPATCH - MONITOR & OPERATE TRANSMISSION SYS	1	2,146,766.13	131,167.17	52,509.76	310.57	2,330,753.63	SG	576,983.85	35,253.65	14,112.99	83.47	626,433.95
5620000	STATION EXPENSES (TRANSMISSION)	106		154.51			154.51	SG	-	41.53	-	-	41.53
5620000	STATION EXPENSES (TRANSMISSION)	109		1,505.57			1,505.57	SG	-	404.65	-	-	404.65
5620000	STATION EXPENSES (TRANSMISSION)	111		188.86	36.05		224.91	SG	-	50.76	9.69	-	60.45
5620000	STATION EXPENSES (TRANSMISSION)	5501		68.00			68.00	SG	-	18.28	-	-	18.28
5620000	STATION EXPENSES (TRANSMISSION)	5701		604.81			604.81	SG	-	162.55	-	-	162.55
5630000	OVERHEAD LINE EXPENSES	5802		(72.72)			(72.72)	SG	-	(19.54)	-	-	(19.54)
5660000	MISC TRANSMISSION EXPENSES	5503		17.00			17.00	SG	-	4.57	-	-	4.57
5680000	MAINTENANCE SUPERVISION AND ENGINEERING	1	32,715.98	-			32,715.98	SG	8,793.04	-	-	-	8,793.04
5693000	MAINTENANCE OF COMMUNICATION EQUIP (TRANSMISSION)	1		2,415.22			2,415.22	SG	-	649.14	-	-	649.14
5700000	MAINTENANCE OF STATION EQUIPMENT	106		1,627.37			1,627.37	SG	-	437.39	-	-	437.39
5700000	MAINTENANCE OF STATION EQUIPMENT	107		356.26			356.26	SG	-	95.75	-	-	95.75
5700000	MAINTENANCE OF STATION EQUIPMENT	108		3,036.60			3,036.60	SG	-	816.14	-	-	816.14
5700000	MAINTENANCE OF STATION EQUIPMENT	109		6,999.81			6,999.81	SG	-	1,881.33	-	-	1,881.33
5700000	MAINTENANCE OF STATION EQUIPMENT	111		629.45	123.62		753.07	SG	-	169.18	33.23	-	202.40
5700000	MAINTENANCE OF STATION EQUIPMENT	5003		32.09			32.09	SG	-	8.62	-	-	8.62
5700000	MAINTENANCE OF STATION EQUIPMENT	5402		8.00			8.00	SG	-	2.15	-	-	2.15
5700000	MAINTENANCE OF STATION EQUIPMENT	5503		129.64			129.64	SG	-	34.84	-	-	34.84
5700000	MAINTENANCE OF STATION EQUIPMENT	540060		26.67			26.67	SG	-	7.17	-	-	7.17
5710000	MAINTENANCE OF OVERHEAD LINES	106		96.01			96.01	SG	-	25.80	-	-	25.80
5710000	MAINTENANCE OF OVERHEAD LINES	107		18.00			18.00	SG	-	4.84	-	-	4.84
5710000	MAINTENANCE OF OVERHEAD LINES	108		1,677.37			1,677.37	SG	-	450.82	-	-	450.82
5710000	MAINTENANCE OF OVERHEAD LINES	109		699.46			699.46	SG	-	187.99	-	-	187.99
5710000	MAINTENANCE OF OVERHEAD LINES	110		819.91			819.91	SG	-	220.37	-	-	220.37
5710000	MAINTENANCE OF OVERHEAD LINES	111		701.09			701.09	SG	-	188.43	-	-	188.43
5710000	MAINTENANCE OF OVERHEAD LINES	5003		31.00			31.00	SG	-	8.33	-	-	8.33
5710000	MAINTENANCE OF OVERHEAD LINES	5303		85.00			85.00	SG	-	22.85	-	-	22.85
5710000	MAINTENANCE OF OVERHEAD LINES	5501		204.00			204.00	SG	-	54.83	-	-	54.83
5710000	MAINTENANCE OF OVERHEAD LINES	5702		100.00			100.00	SG	-	26.88	-	-	26.88
5710000	MAINTENANCE OF OVERHEAD LINES	5802		448.40			448.40	SG	-	120.52	-	-	120.52
5710000	MAINTENANCE OF OVERHEAD LINES	103000		(6.71)			(6.71)	SG	-	(1.80)	-	-	(1.80)
5710000	MAINTENANCE OF OVERHEAD LINES	108000		496.87			496.87	SG	-	133.54	-	-	133.54
5710000	MAINTENANCE OF OVERHEAD LINES	113000		112.17			112.17	SG	-	30.15	-	-	30.15
5710000	MAINTENANCE OF OVERHEAD LINES	119150		77.86			77.86	SG	-	20.93	-	-	20.93
5710000	MAINTENANCE OF OVERHEAD LINES	122000		154.84			154.84	SG	-	41.62	-	-	41.62
5710000	MAINTENANCE OF OVERHEAD LINES	126000		1,721.42			1,721.42	SG	-	462.66	-	-	462.66
5710000	MAINTENANCE OF OVERHEAD LINES	132000		302.32			302.32	SG	-	81.25	-	-	81.25
5710000	MAINTENANCE OF OVERHEAD LINES	134000		1,387.58			1,387.58	SG	-	372.94	-	-	372.94
5710000	MAINTENANCE OF OVERHEAD LINES	136000		(5.92)			(5.92)	SG	-	(1.59)	-	-	(1.59)
5710000	MAINTENANCE OF OVERHEAD LINES	137000		1,099.85			1,099.85	SG	-	295.61	-	-	295.61
5710000	MAINTENANCE OF OVERHEAD LINES	246000		514.83			514.83	SG	-	138.37	-	-	138.37
5710000	MAINTENANCE OF OVERHEAD LINES	576000		57.18			57.18	SG	-	15.37	-	-	15.37
5710000	MAINTENANCE OF OVERHEAD LINES	654000		2,821.11			2,821.11	SG	-	758.23	-	-	758.23
5710000	MAINTENANCE OF OVERHEAD LINES	656100		815.57			815.57	SG	-	219.20	-	-	219.20
5800000	OPERATION SUPERVISION AND ENGINEERING	1	4,061,351.39	1,562.26	39,103.40	9,705.11	4,111,722.16	SNPD	1,153,369.45	443.66	11,104.84	2,756.12	1,167,674.07
5800000	OPERATION SUPERVISION AND ENGINEERING	90	1,152,929.55	939.18	1,419.29	2,199,032.80	3,354,320.82	SNPD	327,416.56	266.71	403.06	624,495.89	952,582.23
5800000	OPERATION SUPERVISION AND ENGINEERING	95	3,140,276.83	74,767.41	54,302.01	79,920.68	3,349,266.93	SNPD	891,796.60	21,232.94	15,421.04	22,696.40	951,146.99
5810000	LOAD DISPATCHING	1	3,098,066.27	770,188.22	6,185.78	249.82	3,874,690.09	SNPD	879,809.37	218,723.15	1,756.68	70.95	1,100,360.14
5820000	STATION EXPENSES (DISTRIBUTION)	2220		270.73			270.73	UT	-	-	-	-	-
5820000	STATION EXPENSES (DISTRIBUTION)	5003		731.78			731.78	UT	-	-	-	-	-
5820000	STATION EXPENSES (DISTRIBUTION)	5004		17.00			17.00	UT	-	-	-	-	-
5820000	STATION EXPENSES (DISTRIBUTION)	5302		56.67			56.67	IDU	-	-	-	-	-
5820000	STATION EXPENSES (DISTRIBUTION)	5402		84.15			84.15	UT	-	-	-	-	-
5820000	STATION EXPENSES (DISTRIBUTION)	5501		68.00			68.00	UT	-	-	-	-	-
5820000	STATION EXPENSES (DISTRIBUTION)	5503		73.98			73.98	UT	-	-	-	-	-
5820000	STATION EXPENSES (DISTRIBUTION)	5701		79.34			79.34	UT	-	-	-	-	-
5820000	STATION EXPENSES (DISTRIBUTION)	133000		171.41			171.41	OR	-	171.41	-	-	171.41

			TOTAL PACIFICORP						OREGON ALLOCATED				
			(d)	(e)			(a)		(d)	(e)			(a)
FERC Acct	FERC Acct Description	Locatn	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries	Factor	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries
5820000	STATION EXPENSES (DISTRIBUTION)	134000		94.73			94.73	OR	-	94.73	-	-	94.73
5820000	STATION EXPENSES (DISTRIBUTION)	240000		-		161.22	161.22	WA	-	-	-	-	-
5820000	STATION EXPENSES (DISTRIBUTION)	563000		131.63			131.63	WYP	-	-	-	-	-
5820000	STATION EXPENSES (DISTRIBUTION)	578000		197.40	4,946.00		5,143.40	WYP	-	-	-	-	-
5820000	STATION EXPENSES (DISTRIBUTION)	655000		194.67			194.67	CA	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	108		168.23	29,833.87		30,002.10	OR	-	168.23	29,833.87	-	30,002.10
5830000	OVERHEAD LINE EXPENSES	5002		-	162.56		162.56	UT	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	5003		(46.91)			(46.91)	UT	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	5004		34.00			34.00	UT	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	5301		34.00	1,191.60		1,225.60	IDU	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	5302		56.67	3,068.46		3,125.13	IDU	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	5303		17.00			17.00	IDU	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	5402		314.93			314.93	UT	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	5404		623.60			623.60	UT	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	5405		(4.50)			(4.50)	UT	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	5501		17.00			17.00	UT	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	5502		27.82			27.82	UT	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	5503		34.00			34.00	UT	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	5801		25.00			25.00	WYU	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	5802		85.00			85.00	WYU	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	14025		116.26			116.26	UT	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	101000		122.58	17,783.02		17,905.60	OR	-	122.58	17,783.02	-	17,905.60
5830000	OVERHEAD LINE EXPENSES	103000		638.99	7,086.55		7,725.54	OR	-	638.99	7,086.55	-	7,725.54
5830000	OVERHEAD LINE EXPENSES	105000		731.19	5,731.88		6,463.07	OR	-	731.19	5,731.88	-	6,463.07
5830000	OVERHEAD LINE EXPENSES	108000		343.18	7,565.44		7,908.62	OR	-	343.18	7,565.44	-	7,908.62
5830000	OVERHEAD LINE EXPENSES	111000		156.56			156.56	OR	-	156.56	-	-	156.56
5830000	OVERHEAD LINE EXPENSES	118000		135.57			135.57	OR	-	135.57	-	-	135.57
5830000	OVERHEAD LINE EXPENSES	119150		217.82	14,483.92		14,701.74	OR	-	217.82	14,483.92	-	14,701.74
5830000	OVERHEAD LINE EXPENSES	120000		137.13	1,893.56		2,030.69	OR	-	137.13	1,893.56	-	2,030.69
5830000	OVERHEAD LINE EXPENSES	122000		374.79			374.79	OR	-	374.79	-	-	374.79
5830000	OVERHEAD LINE EXPENSES	124000		1,446.29	10,343.70		11,789.99	OR	-	1,446.29	10,343.70	-	11,789.99
5830000	OVERHEAD LINE EXPENSES	126000		115.67	6,826.22		6,941.89	OR	-	115.67	6,826.22	-	6,941.89
5830000	OVERHEAD LINE EXPENSES	128000		312.57	13,390.70		13,703.27	OR	-	312.57	13,390.70	-	13,703.27
5830000	OVERHEAD LINE EXPENSES	129000		76.74			76.74	OR	-	76.74	-	-	76.74
5830000	OVERHEAD LINE EXPENSES	131000		84.10	12,561.91		12,646.01	OR	-	84.10	12,561.91	-	12,646.01
5830000	OVERHEAD LINE EXPENSES	132000		75.58			75.58	OR	-	75.58	-	-	75.58
5830000	OVERHEAD LINE EXPENSES	133000		1,006.07	7,147.92		8,153.99	OR	-	1,006.07	7,147.92	-	8,153.99
5830000	OVERHEAD LINE EXPENSES	134000		359.63	7,405.63		7,765.26	OR	-	359.63	7,405.63	-	7,765.26
5830000	OVERHEAD LINE EXPENSES	136000		429.65	13,605.69		14,035.34	OR	-	429.65	13,605.69	-	14,035.34
5830000	OVERHEAD LINE EXPENSES	137000		-	4,329.19		4,329.19	OR	-	-	4,329.19	-	4,329.19
5830000	OVERHEAD LINE EXPENSES	240000		482.61	12,706.34		13,188.95	WA	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	244000		406.11	1,704.16		2,110.27	WA	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	246000		1,093.00	12,474.47		13,567.47	WA	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	578000		15.50			15.50	WYP	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	651000		-	3,049.84		3,049.84	CA	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	651070		215.40			215.40	CA	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	654000		-	7,010.97		7,010.97	CA	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	655000		281.59	10,774.20		11,055.79	CA	-	-	-	-	-
5830000	OVERHEAD LINE EXPENSES	656100		202.79	8,749.73		8,952.52	CA	-	-	-	-	-
5850000	STREET LIGHTING & SIGNAL SYSTEM EXPENSES	1	92,651.46	-			92,651.46	SNPD	26,311.77	-	-	-	26,311.77
5860000	METER EXPENSES	5302		17.00			17.00	IDU	-	-	-	-	-
5860000	METER EXPENSES	5303		17.00			17.00	IDU	-	-	-	-	-
5860000	METER EXPENSES	5502		164.57			164.57	UT	-	-	-	-	-
5860000	METER EXPENSES	5503		119.00			119.00	UT	-	-	-	-	-
5860000	METER EXPENSES	5701		51.00			51.00	UT	-	-	-	-	-
5860000	METER EXPENSES	5802		102.00			102.00	WYU	-	-	-	-	-
5860000	METER EXPENSES	101000		315.65			315.65	OR	-	315.65	-	-	315.65
5860000	METER EXPENSES	103000		18.90	25.00		43.90	OR	-	18.90	25.00	-	43.90
5860000	METER EXPENSES	105000		543.19			543.19	OR	-	543.19	-	-	543.19
5860000	METER EXPENSES	108000		(23.46)			(23.46)	OR	-	(23.46)	-	-	(23.46)
5860000	METER EXPENSES	119150		418.73			418.73	OR	-	418.73	-	-	418.73
5860000	METER EXPENSES	122000		189.05			189.05	OR	-	189.05	-	-	189.05
5860000	METER EXPENSES	124000		465.17			465.17	OR	-	465.17	-	-	465.17
5860000	METER EXPENSES	126000		62.57			62.57	OR	-	62.57	-	-	62.57
5860000	METER EXPENSES	128000		385.79			385.79	OR	-	385.79	-	-	385.79
5860000	METER EXPENSES	129000		64.64			64.64	OR	-	64.64	-	-	64.64
5860000	METER EXPENSES	131000		43.74			43.74	OR	-	43.74	-	-	43.74
5860000	METER EXPENSES	133000		(13.41)			(13.41)	OR	-	(13.41)	-	-	(13.41)
5860000	METER EXPENSES	134000		56.69			56.69	OR	-	56.69	-	-	56.69
5860000	METER EXPENSES	240000		480.41			480.41	WA	-	-	-	-	-
5860000	METER EXPENSES	244000		296.63			296.63	WA	-	-	-	-	-
5860000	METER EXPENSES	246000		587.33	127.86		715.19	WA	-	-	-	-	-

			TOTAL PACIFICORP						OREGON ALLOCATED				
			(d)	(e)			(a)		(d)	(e)			(a)
FERC Acct	FERC Acct Description	Locatn	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries	Factor	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries
5860000	METER EXPENSES	576000		15.50			15.50	WYP	-	-	-	-	-
5860000	METER EXPENSES	578000		51.67			51.67	WYP	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	5003		38.93			38.93	UT	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	5004		102.00			102.00	UT	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	5302		(12.36)			(12.36)	IDU	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	5303		409.17			409.17	IDU	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	5304		17.00			17.00	IDU	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	5404		73.78			73.78	UT	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	5501		1,372.13			1,372.13	UT	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	5502		133.09			133.09	UT	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	5503		144.31			144.31	UT	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	5802		45.34			45.34	WYU	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	101000		572.96			572.96	OR	-	572.96	-	-	572.96
5870000	CUSTOMER INSTALLATIONS EXPENSES	103000		215.46			215.46	OR	-	215.46	-	-	215.46
5870000	CUSTOMER INSTALLATIONS EXPENSES	105000		793.50	112.22		905.72	OR	-	793.50	112.22	-	905.72
5870000	CUSTOMER INSTALLATIONS EXPENSES	108000		37.10			37.10	OR	-	37.10	-	-	37.10
5870000	CUSTOMER INSTALLATIONS EXPENSES	113000		(20.83)			(20.83)	OR	-	(20.83)	-	-	(20.83)
5870000	CUSTOMER INSTALLATIONS EXPENSES	118000		(35.83)	25.00		(10.83)	OR	-	(35.83)	25.00	-	(10.83)
5870000	CUSTOMER INSTALLATIONS EXPENSES	119150		1,844.72	84.94		1,929.66	OR	-	1,844.72	84.94	-	1,929.66
5870000	CUSTOMER INSTALLATIONS EXPENSES	120000		153.32			153.32	OR	-	153.32	-	-	153.32
5870000	CUSTOMER INSTALLATIONS EXPENSES	122000		663.63			663.63	OR	-	663.63	-	-	663.63
5870000	CUSTOMER INSTALLATIONS EXPENSES	124000		180.30			180.30	OR	-	180.30	-	-	180.30
5870000	CUSTOMER INSTALLATIONS EXPENSES	126000		196.05			196.05	OR	-	196.05	-	-	196.05
5870000	CUSTOMER INSTALLATIONS EXPENSES	128000		255.92			255.92	OR	-	255.92	-	-	255.92
5870000	CUSTOMER INSTALLATIONS EXPENSES	129000		150.99			150.99	OR	-	150.99	-	-	150.99
5870000	CUSTOMER INSTALLATIONS EXPENSES	131000		170.81			170.81	OR	-	170.81	-	-	170.81
5870000	CUSTOMER INSTALLATIONS EXPENSES	132000		83.32			83.32	OR	-	83.32	-	-	83.32
5870000	CUSTOMER INSTALLATIONS EXPENSES	133000		502.31			502.31	OR	-	502.31	-	-	502.31
5870000	CUSTOMER INSTALLATIONS EXPENSES	134000		687.40	125.00		812.40	OR	-	687.40	125.00	-	812.40
5870000	CUSTOMER INSTALLATIONS EXPENSES	136000		151.16			151.16	OR	-	151.16	-	-	151.16
5870000	CUSTOMER INSTALLATIONS EXPENSES	137000		(20.11)			(20.11)	OR	-	(20.11)	-	-	(20.11)
5870000	CUSTOMER INSTALLATIONS EXPENSES	240000		532.64			532.64	WA	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	244000		627.66			627.66	WA	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	246000		2,986.89	25.00		3,011.89	WA	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	563000		9.33			9.33	WYP	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	570100		(5.64)			(5.64)	WYP	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	575000		439.54			439.54	WYP	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	576000		371.66			371.66	WYP	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	578000		576.98			576.98	WYP	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	651000		(26.81)			(26.81)	CA	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	654000		192.73			192.73	CA	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	655000		565.61			565.61	CA	-	-	-	-	-
5870000	CUSTOMER INSTALLATIONS EXPENSES	656100		724.33			724.33	CA	-	-	-	-	-
5880000	MISC DISTRIBUTION EXPENSES	1	1,033,466.77	588.84	7,108.74	53,501.05	1,094,665.40	SNPD	293,490.73	167.22	2,018.79	15,193.58	310,870.33
5880000	MISC DISTRIBUTION EXPENSES	90	296,612.77	-		35.70	296,648.47	SNPD	84,234.06	-	-	10.14	84,244.20
5880000	MISC DISTRIBUTION EXPENSES	95	777,252.75	-		2,348.06	779,600.81	SNPD	220,729.38	-	-	666.82	221,396.20
5880000	MISC DISTRIBUTION EXPENSES	5003		34.00			34.00	UT	-	-	-	-	-
5880000	MISC DISTRIBUTION EXPENSES	5501		(12.36)			(12.36)	UT	-	-	-	-	-
5880000	MISC DISTRIBUTION EXPENSES	5802		8.00			8.00	WYU	-	-	-	-	-
5880000	MISC DISTRIBUTION EXPENSES	122000		-			-	OR	-	-	-	-	-
5880000	MISC DISTRIBUTION EXPENSES	122092	135,116.00	-			135,116.00	SNPD	38,371.14	-	-	-	38,371.14
5880000	MISC DISTRIBUTION EXPENSES	246000		85.00			85.00	WA	-	-	-	-	-
5900000	MAINTENANCE SUPERVISION AND ENGINEERING	1	1,131,534.20	2,270.67		1,503.55	1,135,308.42	SNPD	321,340.57	644.84	-	426.99	322,412.40
5900000	MAINTENANCE SUPERVISION AND ENGINEERING	90	302,800.13	(1,173.12)	1,692.30		303,319.31	SNPD	85,991.19	(333.15)	480.59	-	86,138.63
5900000	MAINTENANCE SUPERVISION AND ENGINEERING	95	1,579,888.61	851.64	668.36	1,467,512.62	3,048,921.23	SNPD	448,667.22	241.85	189.81	416,753.95	865,852.83
5920000	MAINTENANCE OF STATION EQUIPMENT	1	837,600.64	1,658.45	10,999.20	700.57	850,958.86	SNPD	237,867.37	470.98	3,123.63	198.95	241,660.93
5920000	MAINTENANCE OF STATION EQUIPMENT	2220		823.29			823.29	UT	-	-	-	-	-
5920000	MAINTENANCE OF STATION EQUIPMENT	5003		1,065.09			1,065.09	UT	-	-	-	-	-
5920000	MAINTENANCE OF STATION EQUIPMENT	5302		298.60			298.60	IDU	-	-	-	-	-
5920000	MAINTENANCE OF STATION EQUIPMENT	5402		264.34			264.34	UT	-	-	-	-	-
5920000	MAINTENANCE OF STATION EQUIPMENT	5501		102.00			102.00	UT	-	-	-	-	-
5920000	MAINTENANCE OF STATION EQUIPMENT	5503		476.78			476.78	UT	-	-	-	-	-
5920000	MAINTENANCE OF STATION EQUIPMENT	5701		42.00			42.00	UT	-	-	-	-	-
5920000	MAINTENANCE OF STATION EQUIPMENT	108000		1,635.58			1,635.58	OR	-	1,635.58	-	-	1,635.58
5920000	MAINTENANCE OF STATION EQUIPMENT	119150		125.90			125.90	OR	-	125.90	-	-	125.90
5920000	MAINTENANCE OF STATION EQUIPMENT	122000		77.48	12,207.86		12,285.34	OR	-	77.48	12,207.86	-	12,285.34
5920000	MAINTENANCE OF STATION EQUIPMENT	133000		291.98			291.98	OR	-	291.98	-	-	291.98
5920000	MAINTENANCE OF STATION EQUIPMENT	563000		83.29	2,523.45		2,606.74	WYP	-	-	-	-	-
5920000	MAINTENANCE OF STATION EQUIPMENT	578000		835.20			835.20	WYP	-	-	-	-	-
5920000	MAINTENANCE OF STATION EQUIPMENT	650000		512.78			512.78	CA	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	1	64,740.21	14.37	330.08		65,084.66	SNPD	18,385.35	4.08	93.74	-	18,483.17
5930000	MAINTENANCE OF OVERHEAD LINES	95	303,838.84	2,538.28	1,019.33		307,396.45	SNPD	86,286.16	720.84	289.48	-	87,296.48

FERC Acct	FERC Acct Description	Locatn	TOTAL PACIFICORP (d) Regular Wages & Salaries	(e) Total Overtime	Other Salary Expense	Bonus/Incentive	(a) Total Wages & Salaries	Factor	OREGON ALLOCATED (d) Regular Wages & Salaries	(e) Total Overtime	Other Salary Expense	Bonus/Incentive	(a) Total Wages & Salaries
5930000	MAINTENANCE OF OVERHEAD LINES	5002		15.00			15.00	UT	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5003		142.65			142.65	UT	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5004		899.31			899.31	UT	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5005		86.67			86.67	UT	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5301		151.01			151.01	IDU	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5302		728.47			728.47	IDU	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5303		4,990.56			4,990.56	IDU	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5304		227.99			227.99	IDU	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5402		183.98	72.10		256.08	UT	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5403		188.00			188.00	UT	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5404		224.93			224.93	UT	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5405		51.00			51.00	UT	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5501		5,510.29			5,510.29	UT	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5502		1,191.79	471.40		1,663.19	UT	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5503		738.56			738.56	UT	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5505		48.40			48.40	UT	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5701		(194.72)			(194.72)	UT	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5802		710.90			710.90	WYU	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	5803		55.93			55.93	WYU	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	101000		2,898.82	18.91		2,917.73	OR	-	2,898.82	18.91	-	2,917.73
5930000	MAINTENANCE OF OVERHEAD LINES	103000		10,602.63	4,523.96		15,126.59	OR	-	10,602.63	4,523.96	-	15,126.59
5930000	MAINTENANCE OF OVERHEAD LINES	105000		11,960.07	37.22		11,997.29	OR	-	11,960.07	37.22	-	11,997.29
5930000	MAINTENANCE OF OVERHEAD LINES	108000		8,623.27	36.87		8,660.14	OR	-	8,623.27	36.87	-	8,660.14
5930000	MAINTENANCE OF OVERHEAD LINES	111000		7,165.50			7,165.50	OR	-	7,165.50	-	-	7,165.50
5930000	MAINTENANCE OF OVERHEAD LINES	113000		2,100.47	114.24		2,214.71	OR	-	2,100.47	114.24	-	2,214.71
5930000	MAINTENANCE OF OVERHEAD LINES	118000		421.19			421.19	OR	-	421.19	-	-	421.19
5930000	MAINTENANCE OF OVERHEAD LINES	119150		6,151.25			6,151.25	OR	-	6,151.25	-	-	6,151.25
5930000	MAINTENANCE OF OVERHEAD LINES	120000		1,789.83			1,789.83	OR	-	1,789.83	-	-	1,789.83
5930000	MAINTENANCE OF OVERHEAD LINES	122000		3,016.69			3,016.69	OR	-	3,016.69	-	-	3,016.69
5930000	MAINTENANCE OF OVERHEAD LINES	124000		1,600.76			1,600.76	OR	-	1,600.76	-	-	1,600.76
5930000	MAINTENANCE OF OVERHEAD LINES	126000		2,447.18			2,447.18	OR	-	2,447.18	-	-	2,447.18
5930000	MAINTENANCE OF OVERHEAD LINES	128000		5,184.61	18.91		5,203.52	OR	-	5,184.61	18.91	-	5,203.52
5930000	MAINTENANCE OF OVERHEAD LINES	129000		611.79			611.79	OR	-	611.79	-	-	611.79
5930000	MAINTENANCE OF OVERHEAD LINES	131000		714.40			714.40	OR	-	714.40	-	-	714.40
5930000	MAINTENANCE OF OVERHEAD LINES	132000		8,539.23			8,539.23	OR	-	8,539.23	-	-	8,539.23
5930000	MAINTENANCE OF OVERHEAD LINES	133000		9,351.78	3,920.90		13,272.68	OR	-	9,351.78	3,920.90	-	13,272.68
5930000	MAINTENANCE OF OVERHEAD LINES	134000		11,987.33	7,272.07		19,259.40	OR	-	11,987.33	7,272.07	-	19,259.40
5930000	MAINTENANCE OF OVERHEAD LINES	136000		8,045.76			8,045.76	OR	-	8,045.76	-	-	8,045.76
5930000	MAINTENANCE OF OVERHEAD LINES	137000		14,877.81	37.79		14,915.60	OR	-	14,877.81	37.79	-	14,915.60
5930000	MAINTENANCE OF OVERHEAD LINES	141070		728.49	18.45		746.94	OR	-	728.49	18.45	-	746.94
5930000	MAINTENANCE OF OVERHEAD LINES	240000		6,477.43			6,477.43	WA	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	244000		2,467.94			2,467.94	WA	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	246000		25,864.88	263.17		26,128.05	WA	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	565100		1,506.95			1,506.95	WYP	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	567300		15.50			15.50	WYP	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	568100		571.67			571.67	WYP	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	575000		1,476.96	148.74		1,625.70	WYP	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	576000		1,585.19	396.10		1,981.29	WYP	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	578000		1,281.00			1,281.00	WYP	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	651070		2,298.49			2,298.49	CA	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	654000		3,832.99			3,832.99	CA	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	655000		5,959.14			5,959.14	CA	-	-	-	-	-
5930000	MAINTENANCE OF OVERHEAD LINES	656100		28,636.89			28,636.89	CA	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5002		39.67			39.67	UT	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5004		455.01			455.01	UT	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5005		17.00			17.00	UT	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5301		77.67			77.67	IDU	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5302		39.67			39.67	IDU	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5303		825.66			825.66	IDU	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5304		22.67			22.67	IDU	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5402		34.00			34.00	UT	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5404		65.00			65.00	UT	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5501		3,653.23			3,653.23	UT	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5502		17.00			17.00	UT	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5503		68.00			68.00	UT	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5505		27.44			27.44	UT	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	5802		424.36			424.36	WYU	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	14025		24.00			24.00	UT	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	101000		1,727.02			1,727.02	OR	-	1,727.02	-	-	1,727.02
5940000	MAINTENANCE OF UNDERGROUND LINES	103000		6,247.66			6,247.66	OR	-	6,247.66	-	-	6,247.66
5940000	MAINTENANCE OF UNDERGROUND LINES	105000		1,110.26			1,110.26	OR	-	1,110.26	-	-	1,110.26
5940000	MAINTENANCE OF UNDERGROUND LINES	108000		7,281.06			7,281.06	OR	-	7,281.06	-	-	7,281.06

			TOTAL PACIFICORP						OREGON ALLOCATED				
			(d)	(e)			(a)		(d)	(e)			(a)
FERC Acct	FERC Acct Description	Locatn	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries	Factor	Regular Wages & Salaries	Total Overtime	Other Salary Expense	Bonus/Incentive	Total Wages & Salaries
5940000	MAINTENANCE OF UNDERGROUND LINES	111000		1,242.71	73.74		1,316.45	OR	-	1,242.71	73.74	-	1,316.45
5940000	MAINTENANCE OF UNDERGROUND LINES	113000		984.29			984.29	OR	-	984.29	-	-	984.29
5940000	MAINTENANCE OF UNDERGROUND LINES	118000		29.36			29.36	OR	-	29.36	-	-	29.36
5940000	MAINTENANCE OF UNDERGROUND LINES	119150		1,708.46			1,708.46	OR	-	1,708.46	-	-	1,708.46
5940000	MAINTENANCE OF UNDERGROUND LINES	120000		475.10			475.10	OR	-	475.10	-	-	475.10
5940000	MAINTENANCE OF UNDERGROUND LINES	122000		1,648.33			1,648.33	OR	-	1,648.33	-	-	1,648.33
5940000	MAINTENANCE OF UNDERGROUND LINES	124000		(141.60)			(141.60)	OR	-	(141.60)	-	-	(141.60)
5940000	MAINTENANCE OF UNDERGROUND LINES	126000		181.89			181.89	OR	-	181.89	-	-	181.89
5940000	MAINTENANCE OF UNDERGROUND LINES	128000		812.92			812.92	OR	-	812.92	-	-	812.92
5940000	MAINTENANCE OF UNDERGROUND LINES	129000		485.79			485.79	OR	-	485.79	-	-	485.79
5940000	MAINTENANCE OF UNDERGROUND LINES	131000		194.98			194.98	OR	-	194.98	-	-	194.98
5940000	MAINTENANCE OF UNDERGROUND LINES	132000		721.98			721.98	OR	-	721.98	-	-	721.98
5940000	MAINTENANCE OF UNDERGROUND LINES	133000		7,120.72			7,120.72	OR	-	7,120.72	-	-	7,120.72
5940000	MAINTENANCE OF UNDERGROUND LINES	134000		(1.37)			(1.37)	OR	-	(1.37)	-	-	(1.37)
5940000	MAINTENANCE OF UNDERGROUND LINES	136000		698.46			698.46	OR	-	698.46	-	-	698.46
5940000	MAINTENANCE OF UNDERGROUND LINES	141070		143.38			143.38	OR	-	143.38	-	-	143.38
5940000	MAINTENANCE OF UNDERGROUND LINES	240000		1,206.71			1,206.71	WA	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	244000		853.43			853.43	WA	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	246000		2,497.21	77.86		2,575.07	WA	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	575000		2,087.28	73.26		2,160.54	WYP	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	576000		224.09			224.09	WYP	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	578000		407.32			407.32	WYP	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	654000		50.61			50.61	CA	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	655000		468.74			468.74	CA	-	-	-	-	-
5940000	MAINTENANCE OF UNDERGROUND LINES	656100		331.83	535.76		867.59	CA	-	-	-	-	-
5950000	MAINTENANCE OF LINE TRANSFORMERS	1	376,925.20	13,187.14	215.85		390,328.19	SNPD	107,041.71	3,744.97	61.30	-	110,847.98
5950000	MAINTENANCE OF LINE TRANSFORMERS	95		1,031.22			1,031.22	SNPD	-	292.85	-	-	292.85
5960000	MAINT OF STREET LIGHT & SIGNAL SYSTEMS	5004		36.87			36.87	UT	-	-	-	-	-
5960000	MAINT OF STREET LIGHT & SIGNAL SYSTEMS	118000		-	25.00		25.00	OR	-	-	25.00	-	25.00
5960000	MAINT OF STREET LIGHT & SIGNAL SYSTEMS	240000		37.81			37.81	WA	-	-	-	-	-
5960000	MAINT OF STREET LIGHT & SIGNAL SYSTEMS	576000		152.76			152.76	WYP	-	-	-	-	-
5960000	MAINT OF STREET LIGHT & SIGNAL SYSTEMS	578000		20.67			20.67	WYP	-	-	-	-	-
5960000	MAINT OF STREET LIGHT & SIGNAL SYSTEMS	656100		251.94			251.94	CA	-	-	-	-	-
5970000	MAINTENANCE OF METERS	1	507,224.77	57.00	5,144.38	72.72	512,498.87	SNPD	144,045.05	16.19	1,460.94	20.65	145,542.82
5970000	MAINTENANCE OF METERS	109	707,258.94	11,610.13	34.77		718,903.84	UT	-	-	-	-	-
5970000	MAINTENANCE OF METERS	5503		34.00			34.00	UT	-	-	-	-	-
5970000	MAINTENANCE OF METERS	105000		4.44			4.44	OR	-	4.44	-	-	4.44
5980000	MAINTENANCE OF MISC DISTRIBUTION PLANT	90	114,171.80	-			114,171.80	SNPD	32,423.26	-	-	-	32,423.26
5980000	MAINTENANCE OF MISC DISTRIBUTION PLANT	95	168,122.12	102.64			168,224.76	SNPD	47,744.43	29.15	-	-	47,773.58
5980000	MAINTENANCE OF MISC DISTRIBUTION PLANT	136000		188.95			188.95	OR	-	188.95	-	-	188.95
7071000	LABOR CLEARING - ROCKY MTN POWER	99	32,325,163.99	6,631,809.72	466,743.75	825.09	39,424,542.55	OTHER	-	-	-	-	-
7072000	LABOR CLEARING - PACIFIC POWER	98	21,237,525.31	4,631,165.26	302,061.61	6,842.26	26,177,594.44	OTHER	-	-	-	-	-
9010000	SUPERVISION (CUSTOMER ACCOUNTS)	1	229,393.71	521.14	(10.23)	1,458.85	231,363.47	CN	71,038.77	161.39	(3.17)	451.78	71,648.77
9010000	SUPERVISION (CUSTOMER ACCOUNTS)	90		-		2,281.08	2,281.08	CN	-	-	-	706.41	706.41
9010000	SUPERVISION (CUSTOMER ACCOUNTS)	1160	366,632.29	3,854.45	(9,301.88)	1,455.35	362,640.21	CN	113,538.89	1,193.65	(2,880.61)	450.69	112,302.62
9020000	METER READING EXPENSES	1	385,402.31	-		47.80	385,450.11	CN	119,351.60	-	-	14.80	119,366.40
9020000	METER READING EXPENSES	90	70,035.13	-	41.38	1,001.87	71,078.38	CN	21,688.52	-	12.81	310.26	22,011.59
9020000	METER READING EXPENSES	109	49,985.70	-			49,985.70	UT	-	-	-	-	-
9020000	METER READING EXPENSES	5003	222,694.86	9,989.53	167.66		232,852.05	UT	-	-	-	-	-
9020000	METER READING EXPENSES	5303	470,315.32	23,856.99	828.78	500.00	495,501.09	IDU	-	-	-	-	-
9020000	METER READING EXPENSES	5304		456.09			456.09	IDU	-	-	-	-	-
9020000	METER READING EXPENSES	5402	268,223.07	14,479.12	3,676.97	4,642.34	291,021.50	UT	-	-	-	-	-
9020000	METER READING EXPENSES	5404	593,562.30	27,225.42	18,050.38	(3,697.55)	635,140.55	UT	-	-	-	-	-
9020000	METER READING EXPENSES	5501	532,562.55	24,884.85	433.48		557,880.88	UT	-	-	-	-	-
9020000	METER READING EXPENSES	5502		17.00			17.00	UT	-	-	-	-	-
9020000	METER READING EXPENSES	5503		17.00			17.00	UT	-	-	-	-	-
9020000	METER READING EXPENSES	5701	398,921.13	17,570.78	923.10	692.43	418,107.44	UT	-	-	-	-	-
9020000	METER READING EXPENSES	103000		-	25.00		25.00	OR	-	-	25.00	-	25.00
9020000	METER READING EXPENSES	108000	1,118,344.43	115,697.32	8,063.78		1,242,105.53	OR	1,118,344.43	115,697.32	8,063.78	-	1,242,105.53
9020000	METER READING EXPENSES	119150	370,921.75	40,311.42	4,535.38		415,768.55	OR	370,921.75	40,311.42	4,535.38	-	415,768.55
9020000	METER READING EXPENSES	122000	570,160.87	31,141.33	1,165.53	88.49	602,556.22	OR	570,160.87	31,141.33	1,165.53	88.49	602,556.22
9020000	METER READING EXPENSES	126000		37.99			37.99	OR	-	37.99	-	-	37.99
9020000	METER READING EXPENSES	133000	452,287.03	25,207.45	5,609.39		483,103.87	OR	452,287.03	25,207.45	5,609.39	-	483,103.87
9020000	METER READING EXPENSES	136000	865,024.42	77,123.03	6,577.06		948,724.51	OR	865,024.42	77,123.03	6,577.06	-	948,724.51
9020000	METER READING EXPENSES	246000	992,356.86	68,136.37	10,397.33	270.00	1,071,160.56	WA	-	-	-	-	-
9020000	METER READING EXPENSES	563000	637,857.26	51,199.34	9,031.84	14,847.82	712,936.26	WYP	-	-	-	-	-
9020000	METER READING EXPENSES	578000	605,018.50	28,210.77	827.18		634,056.45	WYP	-	-	-	-	-
9030000	CUSTOMER RECORDS AND COLLECTION EXPENSES	1	170,261.33	-	393.58		170,654.91	CN	52,726.62	-	121.88	-	52,848.51
9031000	CUSTOMER RECORDS AND CUSTOMER SYSTEM EXPENSE	1	717,791.10	-		2,571.40	720,362.50	CN	222,285.94	-	-	796.31	223,082.25
9032000	CUSTOMER ACCOUNTING - BILLING	1	518,807.86	13,732.48	1,001.26	20,728.45	554,270.05	CN	160,664.70	4,252.68	310.07	6,419.20	171,646.65
9033000	CUSTOMER ACCOUNTING - COLLECTIONS	1160	2,484,297.29	85,217.73	6,895.78	106.68	2,576,517.48	CN	769,338.54	26,390.27	2,135.49	33.04	797,897.34
9033000	CUSTOMER ACCOUNTING - COLLECTIONS	5001	9,669.15	119.20	487.65		10,276.00	UT	-	-	-	-	-

			TOTAL PACIFICORP						OREGON ALLOCATED				
			(d)	(e)			(a)		(d)	(e)			(a)
FERC Acct	**FERC Acct Description**	**Locatn**	**Regular Wages & Salaries**	**Total Overtime**	**Other Salary Expense**	**Bonus/Incentive**	**Total Wages & Salaries**	**Factor**	**Regular Wages & Salaries**	**Total Overtime**	**Other Salary Expense**	**Bonus/Incentive**	**Total Wages & Salaries**
9033000	CUSTOMER ACCOUNTING - COLLECTIONS	5502		34.00			34.00	UT	-	-	-	-	-
9033000	CUSTOMER ACCOUNTING - COLLECTIONS	5701	64,023.86	1,721.76			65,745.62	UT	-	-	-	-	-
9033000	CUSTOMER ACCOUNTING - COLLECTIONS	101000		(8.79)			(8.79)	OR	-	(8.79)	-	-	(8.79)
9033000	CUSTOMER ACCOUNTING - COLLECTIONS	108000		25.48			25.48	OR	-	25.48	-	-	25.48
9033000	CUSTOMER ACCOUNTING - COLLECTIONS	133000		37.79			37.79	OR	-	37.79	-	-	37.79
9033000	CUSTOMER ACCOUNTING - COLLECTIONS	244000		465.09			465.09	WA	-	-	-	-	-
9033000	CUSTOMER ACCOUNTING - COLLECTIONS	563000	9,555.50	87.00	(34,986.25)	44,543.46	19,199.71	WYP	-	-	-	-	-
9033000	CUSTOMER ACCOUNTING - COLLECTIONS	575000	2,791.80	(111.04)	644.00		3,324.76	WYP	-	-	-	-	-
9033000	CUSTOMER ACCOUNTING - COLLECTIONS	576000	18,912.25	1,034.56			19,946.81	WYP	-	-	-	-	-
9036000	CUSTOMER ACCOUNTING - COMMON	1		-		1,109,470.00	1,109,470.00	CN	-	-	-	343,581.28	343,581.28
9036000	CUSTOMER ACCOUNTING - COMMON	90		-		193,522.00	193,522.00	CN	-	-	-	59,930.00	59,930.00
9036000	CUSTOMER ACCOUNTING - COMMON	112106	3,842,430.99	121,933.64	8,767.74	357.00	3,973,489.37	CN	1,189,926.13	37,760.48	2,715.20	110.56	1,230,512.36
9036000	CUSTOMER ACCOUNTING - COMMON	122106	1,033,429.55	692.55		142.78	1,034,264.88	CN	320,033.03	214.47	-	44.22	320,291.71
9050000	MISC CUSTOMER ACCOUNTS EXPENSES	1	50,348.41	-			50,348.41	CN	15,591.92	-	-	-	15,591.92
9070000	SUPERVISION (CUSTOMER SERVICE & INFO)	1	79,379.72	-	(5,125.00)		74,254.72	CN	24,582.36	-	(1,587.11)	-	22,995.24
9080000	CUSTOMER ASSISTANCE EXPENSES	1	511,850.71	1,458.17	1,869.10	649.84	515,827.82	CN	158,510.21	451.57	578.82	201.24	159,741.84
9081000	CUSTOMER ASSISTANCE EXPENSE - GENERAL	112106		-	11,809.25		11,809.25	CN	-	-	3,657.09	-	3,657.09
9084000	DSM DIRECT EXPENSES	1	415,877.15	-		61,413.85	477,291.00	CN	128,789.06	-	-	19,018.67	147,807.74
9086000	CUSTOMER SERVICE	1	85,216.96	284.85	(20,833.35)	133.31	64,801.77	CN	26,390.03	88.21	(6,451.68)	41.28	20,067.85
9086000	CUSTOMER SERVICE	106	121,202.42	-		747.06	121,949.48	IDU	-	-	-	-	-
9086000	CUSTOMER SERVICE	108	339,042.74	-			339,042.74	OR	339,042.74	-	-	-	339,042.74
9086000	CUSTOMER SERVICE	109	614,121.51	-	440.30	247.10	614,808.91	UT	-	-	-	-	-
9086000	CUSTOMER SERVICE	114	290,566.67	-			290,566.67	WYP	-	-	-	-	-
9090000	INFORMATIONAL & INSTRCT ADVERTISING EXP	1	148,103.72	(103.30)	(15,583.35)	171.40	132,588.47	CN	45,864.84	(31.99)	(4,825.86)	53.08	41,060.07
9200000	ADMINISTRATIVE AND GENERAL SALARIES	1	15,300,016.98	73,965.87	400,460.09	2,787,265.25	18,561,708.19	SO	4,323,258.18	20,900.21	113,156.24	787,585.22	5,244,899.85
9200000	ADMINISTRATIVE AND GENERAL SALARIES	90	2,083,182.55	3,365.85	1,775.39	652,845.40	2,741,169.19	SO	588,635.69	951.07	501.66	184,471.64	774,560.06
9200000	ADMINISTRATIVE AND GENERAL SALARIES	95	1,141,267.57	430.33	8,707.95	379,512.46	1,529,918.31	SO	322,482.93	121.60	2,460.57	107,237.16	432,302.26
9200000	ADMINISTRATIVE AND GENERAL SALARIES	106		-	254,247.70		254,247.70	IDU	-	-	-	-	-
9200000	ADMINISTRATIVE AND GENERAL SALARIES	110		-	265,436.40		265,436.40	WA	-	-	-	-	-
9200000	ADMINISTRATIVE AND GENERAL SALARIES	114		-	663,888.90		663,888.90	WYP	-	-	-	-	-
9200000	ADMINISTRATIVE AND GENERAL SALARIES	122092	232,099.76	-		107.08	232,206.84	SO	65,583.40	-	-	30.26	65,613.66
9290000	DUPLICATE CHARGES - CR	122092		-		3,400.00	3,400.00	SO	-	-	-	960.72	960.72
9350000	MAINTENANCE OF GENERAL PLANT	1	736,823.10	6,353.73	4,493.45	88,818.78	836,489.06	SO	208,200.85	1,795.35	1,269.69	25,097.13	236,363.02
9350000	MAINTENANCE OF GENERAL PLANT	1034		76.17	188.08		264.25	SO	-	21.52	53.14	-	74.67
	TOTAL Wages and Salaries		**173,400,817.79**	**23,826,040.85**	**3,566,444.91**	**13,940,323.27**	**214,733,626.82**		**34,155,152.34**	**3,624,268.65**	**575,669.23**	**3,894,441.38**	**42,249,531.60**

UE-210/PacifiCorp
May 20, 2009
OPUC Data Request 206

OPUC Data Request 206

As a follow up to DR No. 89, please provide work papers showing the calculations of the "659 conversions to Enhanced 401(k)" amount of $7,127,068 as well as the "Nonunion conversion to Enhanced 401(k)" amount of $12,900,000. Along with the work papers, please provide a written explanation of the calculations/assumptions and copies of any supporting documentation.

Response to OPUC Data Request 206

Upon further investigation of the Enhanced 401(k) included in the 2010 plan, it was discovered that the entire cost of the conversion to the Enhanced 401(k) is included in the $12,900,000, and the $7,127,068 should not have been included in addition. Removing the $7,127,068 will result in a reduction of the 401(k) cost included in the case by that amount. The result is a reduction to the Oregon revenue requirement by approximately $1.4 million as detailed in the table below. The Company's rebuttal position will reflect this change.

Total 401(k) cost to remove	7,127,068
Joint Owner Reduction	97.1%
Total Company Cost Reduction	6,919,258
O&M portion	71.45%
Total Company Expense Reduction	4,943,823
Approximate Oregon Portion - SO	28.26%
Oregon expense reduction	1,396,954

Please see Attachment OPUC 206 for the source of the additional $12.9 million cost due to 401(k) Enhancements. The breakdown of this amount between groups is:

Nonunion - $8.3 million
Local 659 - $3.1 million
Local 125 - $1.5 million

Please refer to non-confidential Attachment OPUC 206 on the enclosed CD.