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

A. My name is J. Ted Weston. My business address is One Utah Center, Suite 2300 at 201 South Main Salt Lake City, Utah 84111. My present position is Manager of Revenue Requirement in the Regulation Department.

Qualifications

Q. Please briefly describe your education and business experience.

A. I received a Bachelor of Science Degree in Accounting from Utah State University in 1983. I joined the Company in June of 1983 and I have held various accounting and regulatory positions prior to my current position. In addition to formal education, I have attended various educational, professional and electric industry related seminars during my career with the Company.

Q. What are your responsibilities?

A. My primary responsibilities include overseeing the calculation and reporting of the Company's regulated earnings or revenue requirement, assuring that the interjurisdictional cost allocation methodology is correctly applied and the explanation of those calculations to regulators in the jurisdictions in which PacifiCorp operates.

Purpose of Testimony

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

A. The purpose of my testimony is to present the Company's Utah Results of Operations Report, labeled as Exhibit UP&L___(JTW-1), for the twelve months ending September 30, 2007 (the "Test Period"). My testimony presents evidence that based on its results of operations for this Test Period; PacifiCorp will earn an overall return on equity ("ROE") in Utah of 3.9 percent. This return is less than the ROE currently authorized by the Utah Public Service Commission (the "Commission") and is less than the return recommended in Dr. Sam Hadaway's testimony to provide a fair and equitable return for the Company's shareholders. An overall price increase of $228.8 million is required to produce the 11.4 percent ROE requested by the Company in this proceeding.

Q. Is the Company requesting the full $228.8 million required to earn an 11.4 percent ROE?

A. No. The Company has reflected the Rate Mitigation cap as stipulated and approved by the Utah PSC approved in Docket No. 02-035-04. The stipulation states:

> "In order to mitigate potential rate impacts on Utah customers, any increase in the Utah revenue requirement as a result of the implementation of the Revised Protocol shall be capped at the Applicable Percentage of the Company's Utah Revenue Requirement calculated under the Rolled-In Allocation Method for the indicated effective periods as follows: 101.5 percent for the period from the effective date of the final PSCU order in the first general rate proceeding filed after the effective date of this Stipulation and the Revised Protocol, to March 31, 2007".

This adjustment reduces the rate request by $24.9 million to $204 million and is shown in my Exhibit UP&L___(JTW-1) on page 1.0 of Tab 1 Summary.

Q. Does this represent the costs the Company projects to experience during the rate effective period?

A. Yes. This reflects the current projections of the Company's costs. However, in anticipation of the closing of the MEHC transaction, the Company has included an additional adjustment that reduces the rate increase by $6.7 million. Supplemental testimony identifying specific impacts that MEHC Ownership will have on PacifiCorp operating costs will be filed 15 days after the transaction closing by a MEHC witness.

Development of Forecasted Test Period Results of Operations

Q. Please explain the process used to calculate the results of operations for the Test Period.

A. Pursuant to the stipulation in Docket 04-035-42, the Company has developed the Test Period in three steps; first, the Company started with the historical base of twelve-months ending September 30, 2005 ("Actual Period"). The Actual Period was normalized to remove any non-recurring items, unusual weather or hydro conditions and then annualized to reflect an annual level for any contract or price changes that occurred during that period. These normalized results of operations are summarized as the "Base Period".

The second step was to develop the "Mid Period" which is the twelve-months ending September 30, 2006. The Mid Period utilizes the load forecast developed by Mr. Mark Klein for that time frame. Retail revenues were forecasted by applying the current tariffs to the Mid Period load forecasts. Net power costs, which were developed using the Generation & Regulation Initiative

Decision ("GRID") model, utilized the same load forecast. The normalized Base Period operation, maintenance, administrative and general ("OMAG") expenses were split between labor related and non-labor costs. The non-labor costs were escalated by utilizing functional specific (i.e. production, transmission, distribution, etc.) inflation indices prepared by Global Insight's Utility Cost of Service. These results were then compared to the budget for the corresponding period. In limited areas where the budget differed significantly from the escalated amounts, the known cost drivers were identified and the differences added to the escalated amounts to better reflect the expected Mid Period operating conditions.

Labor costs were adjusted to capture wage and employee benefit increases through the end of the Mid Period. The labor and non-labor costs were then combined.

Pursuant to the stipulation in Docket 04-035-42, the Company has provided Actual, Base and Mid period summaries along with supporting functional detailed reports in the B tabs for the Actual period in Exhibit UP&L___(JTW-2).

The final step was to walk the Mid Period out to the Test Period Results of Operations. The same process used to walk the Base Period to the Mid Period was employed. The load forecast for the twelve-months ending September 30, 2007 was the basis for developing the MSP Revised Protocol allocation factors, the general business revenues and the net power costs. Non-labor OMAG was escalated to capture another year of inflation and labor related expenditures were adjusted for increases to wage and benefits. Electric plant in service was developed from the Company's capital budgets based on project spend and completion dates.

The development of the Test Period results is summarized in six tabs in Exhibit UP&L___(JTW-1), the "Report". Revenues are summarized in Tab 3 - Revenue Summary. The OMAG forecast is summarized in Tab 4 - O&M Summary. The net power cost forecast was produced using the GRID model and is summarized under Tab 5 - Net Power Cost Summary. Annual depreciation expense was developed by applying the Company's composite functional depreciation rates to the forecasted plant balances as summarized in Tab 6 - Depreciation and Amortization Summary. Tab 7 is the Tax Summary. Tab 8 contains the Rate Base Summary.

There are two additional tabs, Tab 9 - Rolled-In Methodology restates the results summarized in Tab 2 utilizing the Rolled-In allocation in compliance with the MSP Revised Protocol approval order. Tab 10 – Allocations, shows the derivation of the Revised Protocol Allocation Method ("Revised Protocol") factors.

I will discuss the calculation of each of these components in more detail later in my testimony.

Q. Please explain how inflation escalators were used in your forecast.

A. The Company's cost of goods necessary to provide customer service are impacted by inflation just like everyone else. To develop the Test Period, the Company starts with normalized historical expenses, (Base Period). Non-labor costs were isolated from labor costs, utility cost indices were used to escalate the Base Period costs to the Test Period, with the exception of insurance and net power costs. The advantage of using inflation indices to produce a forecast is that the resulting calculations are easily understood and readily verifiable.

Q. Are there additional areas where future cost increases will not track the general rate of inflation?

A. Yes. In order to rely solely on inflation indices, all the cost components that the Company will incur in the future need to be in the Base Period. For example, in order to serve growing system loads and maintain or improve system reliability and generation plant availability, the Company will be making substantial capital investment as well as increasing its distribution O&M expense over the historic levels in the Base Period. The Company will also bring Current Creek Phase II and the Lakeside project on-line in the Test Period. Because of the new plant resources and growth in specific cost categories, a forecast test year based entirely on indexed inflation changes would not capture all conditions expected in the rate-effective period.

Q. Who provides the utility indices used by the Company to forecast OMAG costs?

A. The indices are developed by Global Insight. The Company has relied on Global Insight's indices to develop load forecasts for its Integrated Resource Plan and in forecast test period rate cases in Oregon, California, Wyoming and the last Utah GRC.

Q. Why does the Company use Global Insight's inflation indices?

A. Global Insight provides a detailed assessment of the electric market and is a utility cost index with the most granular level of detail available. There are many high-level indices that are both historical and forward-looking. One of the most recognized and generally accepted indices is the Consumer Price Index ("CPI"). CPI contains a select basket of goods which include food, housing, utility costs, apparel, transportation, recreation, education, and other goods and services. In contrast, Global Insight's index is based on electric utility costs according to the Uniform System of Accounts defined by the Federal Energy Regulatory Commission ("FERC") for major electric utilities and major natural gas pipeline companies. The study used to prepare this filing was Global Insight's Utility Costs of Service, release dated November 18, 2005. A summary of these indices is in tab 4.16.

Q. At what level are Global Insight's indices prepared?

A. Global Insight's indices are prepared at the FERC functional subcategory level and are denoted with their corresponding FERC account number. The individual FERC account level indices are then combined into broader indices representing operation, maintenance, or total operation and maintenance expenses.

Q. Does the Company use Global Insight's indices to escalate labor costs?

A. No. The Company uses the Global Insight non-labor index to escalate non-labor OMAG costs only.

Q. How has the Company addressed areas where cost increases were different than inflation?

A. After OMAG was calculated, it was compared to the Company's budget. In areas where there were large discrepancies, the appropriate business unit within the

Company was asked to provide documentation to support these differences. In most cases, these differences were attributed to changes in the number, or frequency, of activities. Inflation indices capture cost increases on existing units of production; they don't capture changes in volume. Examples of these types of adjustments are the Power Delivery New Programs (Adjustment 4.10), Generation Overhaul (Adjustment 4.11), and Incremental Generation O&M for new plants (Adjustment 4.12) and Generation Operation & Maintenance Normalization (Adjustment 4.13).

Q. Please describe Exhibit UP&L___(JTW-1).

A. Exhibit UP&L___(JTW-1), which was prepared under my direction, is PacifiCorp's Utah Results of Operations Report (the "Report"). As discussed above, the Base Period for the Report are the twelve-months ending September 30, 2005, which has been normalized and is used to calculate the Test Period revenue requirement. The Report provides totals for revenues, expenses, depreciation, net power costs, taxes, rate base and loads starting with September 2005 historical amounts and walking forward to the Test Period. Electric plant in service, other working capital, accumulated depreciation and amortization reserves are thirteen month averages. The Company has used a thirteen-month average to better match new generation investment with maintenance and net power costs. All other rate base balances are beginning period end of period averages. The Report presents operating results for the period in terms of both return on rate base and ROE.

Q. Please describe how Exhibit UP&L___(JTW-1) is organized.

A. Tab 1 Summary is the Utah allocated results based on the Revised Protocol allocation methodology. Page 1.0 is the calculation of the rate mitigation cap which compares the revenue requirement from Rolled-In allocation to Revised Protocol and caps the increase at the lower of Revised Protocol or 101.5 percent of Rolled-In. Page 1.1, starting with column (1), labeled Total Adjusted Results is the Utah results of operations for the Test Period. The Total Adjusted Results column is carried forward from the results of operations summary, Page 2.2, and shows Utah's ROE at 3.9 percent. The Price Change (column 2 of Tab 1, page 1.1) shows that a price increase of $228.8 million in revenues is required to increase the return on equity from 3.9 percent to 11.4 percent in Utah. Column 3 reflects the Utah adjusted revenue requirement with the $228.8 million price increase included. Page 1.2, of Tab 1, supports the calculation of additional revenue-related uncollectible expense and franchise taxes associated with the price change requested in column 2. Page 1.3 details the calculation of the net operating income percentage.

Tab 2 details Total Company and Utah allocated results based on the Revised Protocol allocation methodology. Pages 2.3 through 2.39 contain revenues, expenses and rate base detail by FERC Account. Supporting documentation for the data in Tab 2 is provided under Tabs 3 through 8. The Adjusted Total Column of the results on Tab 2, page 2.2, reflects the costs, revenues and rate base that have been calculated as described later in my testimony. The normalizing adjustments made to Actual Period data to reflect ongoing costs of the Company are described in Tabs 3 through 8. Tab 9 is Tab 2 restated with the Utah allocation based on the Rolled-In allocation method. Tab 10 contains the calculation of the Revised Protocol allocation factors. The load forecast used for these factor calculations and to calculate the revenue and net power costs are explained further in testimony sponsored by Company witness Mr. Mark Klein.

Q. Please describe some of the key areas where the Company has experienced cost increases driving the need for the requested price increase.

A. PacifiCorp has incurred increases in six main areas to serve its Utah customers: new plant investment, net power costs, generation-related operation and maintenance costs, Power Delivery program costs, increased cost of capital, and employee labor and benefits.

- The Company continues to make significant investment to serve its customers. Utah allocated net rate base has increased by $460 million from the amount included in the Company's last Utah filing and the associated depreciation expense is up $21 million. This filing includes Phase II of the Currant Creek facility, which improves the efficiency of this resource by converting it to a combined cycle combustion turbine enabling an additional 245 MW of capacity for a total of 525 MW and the Lakeside facility with 534 MW additional production capacity. These generation resources are explained in the direct testimony of Mr. Mark Tallman. The capital costs associated with the Huntington 2 Scrubber are also included in this filing and are discussed in the direct testimony of Mr. Barry Cunningham. In addition this filing includes $145 million of new investment in transmission projects and $76 million of distribution all here in Utah which is discussed in Mr. Darrell Gerrard's testimony.

- Net power costs, as addressed by Mr. Mark Widmer, continue to increase due to a combination of increasing fuel costs, purchased power and customer load growth. In Docket No. 04-035-45, net power costs were filed at $745 million compared to $813 million requested in this application.
- Mr. Barry Cunningham's testimony explains that the Company is experiencing rising costs in three main areas associated with maintaining PacifiCorp's low-cost but aging generation fleet. They are overhaul costs, incremental operation and maintenance for Current Creek, Lakeside and the Huntington scrubber, and increased maintenance of an aging fleet.
- Mr. Darrell Gerrard's testimony describes the impacts of increased vegetation management, EMS/SCADA controls and new power delivery programs.
- Mr. Bruce Williams explains the need to increase the Company's equity ratio of the capital structure from 47.80 percent to 52.80 percent and Dr. Sam Hadaway's testimony supports 11.4 percent return on that equity ratio.
- The Company continues to experience increases in the areas of pensions and benefits. Mr. Daniel Rosborough discusses these costs and describes the efforts of the Company to control these increasing costs.

Revenues

Q. Please describe the procedures used to forecast the Company's Test Period revenues and explain the entries behind Tab 3, Revenue Adjustments.

A. The revenue forecast and adjustments are contained in Tab 3, which begins with an overview of assumptions used to forecast retail revenues and a brief explanation of each additional normalization adjustment made to other revenues. This is followed by a numerical summary (pages 3.0.2 – 3.0.10) by FERC account and allocation factor starting with actual revenue and summarizing each adjustment to get from there to the Test Period.

Tab 3.1 Rev. Normalization & Forecasts – This tab has the incremental changes to walk from historical revenues to the Test Period forecasted revenues shown on page 3.1.3. It also includes the load forecasts for those periods.

Tab 3.2 Other Electric Revenues – This tab has three adjustments to account 456.

- Bonneville Power Association ("BPA") has a contract with the Company for the use of a 500/230 Kv transformer bank at the Malin substation. BPA began using these facilities in January 1999, but no payment was made until January 2005. This resulted in a back payment in the Base Period for the use of the facilities over the five years. This adjustment removes the prior-period payments leaving only the annual ongoing level of revenues in the Test Period.
- Intermountain Power Agency and Deseret Generation and Transmission have a use of facilities contract with the Company for use of the Mona

substation. During the base period a contract dispute was resolved and back payments were received. We have normalized the revenues to the annual level for the use of these facilities.

- This adjustment removes Oregon and Washington's amortization of the Centralia gain to eliminate any tax impacts from results.

Tab 3.3 WAPA Wheeling – In compliance with the Utah Public Service Commission order in Docket No. 99-035-10, the Company has imputed revenues to adjust the WAPA wheeling contract to current FERC tariff for wheeling.

Tab 3.4 Comcast Revenues – In September 2003, Comcast paid PacifiCorp for unauthorized pole attachments; however Comcast disputed some of the claims. During the base period a settlement was reached between the parties for the amount of unauthorized pole attachments. The Company refunded $301,859 to Comcast to settle the dispute based on Commission order in Docket No. 03-035-28. This adjustment removes the effect of this non-recurring event from results.

Tab 3.5 SO2 Emission Allowances – In the Base Period, after an extended period of selling the minimum level of SO2 allowances, the Company elected to increases its sales of excess SO2 allowances. Consistent with the Commission order in Docket No. 97-035-10, the Company has amortized all sales over a four-year period. In addition, this adjustment includes forecasted sales through the end of the test period.

Q. Are there additional adjustments to revenue that are included in other portions of the Exhibit?

A. Yes.

Tab 5.1 Net Power Cost Adjustments – A portion of this adjustment aligns wholesale sales from the Base Period to the results generated in the GRID model. Mr. Widmer explains how these sales were forecasted in his testimony.

Tab 5.2 James River & Little Mountain Offset – Includes the revenue offset based on the terms of these contracts. These adjustments are explained further in the net power costs section of my testimony.

Operation, Maintenance, Administrative & General ("OMAG") Expenses

Q. How is Tab 4 organized?

A. Tab 4 includes the O&M summary followed by the adjustments themselves.

Q. What is the O&M Summary and what is its purpose?

A. The O&M Summary is an overview that provides assumptions and itemizes the adjustments made to adjust OMAG costs forward from the Base Period to the Test Period. It is the bridge between the OMAG section in the results of operations (Tab 2) and the detail supporting the Company's Test Period OMAG projections (Tab 4).

The OMAG Summary begins on page 4.0 with a brief overview of assumptions used to forecast OMAG. It is organized by FERC account and allocation factor starting with unadjusted data from the Base Period. Labor costs are adjusted separately so the second column subtracts the Actual Period labor costs, leaving non-labor OMAG. Each following column has a numerical reference to a corresponding tab in Exhibit UP&L___(JTW-1), which contains a lead sheet. This lead sheet shows the FERC account affected by the adjustment, allocation factor, dollar amount and a brief description of the adjustment.

Q. Please describe the OMAG numerical summary.

A. The numerical summary is found on page 4.0.1 through page 4.0.15. The detail in this tab supports pages 2.5 through 2.14. Each adjustment is listed in a separate column. These columns are totaled to produce the Base Period normalized OMAG shown in the column on the right-hand side of the page titled “Sep 2005 Adjusted O&M” summarized on pages 4.0.1 through 4.0.5.

To walk OMAG expenses forward from the Base Period to the Mid Period, the process is repeated as shown on pages 4.0.6 through 4.0.10. The Base Period labor costs were removed, leaving non-labor OMAG. These costs are then escalated to Mid Period levels using Global Insight’s indices for each FERC function, the result is then adjusted for items that weren’t escalated like property insurance and incremental OMAG and net power costs. The Mid Period labor costs were added back in with the other normalizing adjustments to produce the Mid Period (September 2006) OMAG expense.

Finally, the process is repeated one more time to walk forward the Mid Period OMAG to the Test Period, summarized on pages 4.0.11 through 4.0.15.

Q. Please describe the adjustments made to base year non-labor OMAG expense in Tab 4.

A. **Tab 4.1 Blue Sky Program Costs –** The Blue Sky Program is designed to encourage voluntary customer participation in the acquisition and development of renewable resources. To protect non-participants from subsidizing this program, this adjustment removes expenses (administrative costs and green tag purchase costs) associated with this program from the Test Period.

Tab 4.2 Miscellaneous General Expense – This adjustment removes from results of operations certain miscellaneous expenses that should have been charged below the line to non-regulated expenses.

Tab 4.3 International Assignees – The International Assignee adjustment removes housing and other costs associated with international assignees who have either returned to Scotland or "localized" (transferred to the U.S. compensation package). Those remaining on ScottishPower's compensation plan have been adjusted to the lower of their actual compensation or the equivalent PacifiCorp compensation. Out of period costs and outside services related to personal tax preparation services for all International Assignees have also been removed.

Tab 4.4 Customer Service Deposits – As specified in Utah Electric Service Regulation No. 9, the Company pays interest on customer service deposits. These deposits are treated as a reduction to rate base and interest is treated as an expense of electric operations. Absent this adjustment, the interest true-up would nullify any recovery of customer service deposits. This treatment was approved in Docket No. 97-035-01.

Tab 4.5 Uncollectible Accounts – During the base year, five different prior period reserves were adjusted, resulting in a $5.5 million credit allocated across all jurisdictions. This adjustment removes these non-recurring items from the Test Period.

- The first item for $1,234,871 was a reserve created December 2002 for the joint-owner's share of Trail Mountain Mine closure costs. In November 2004, the dispute was resolved and the reserve written-off. The joint-owner's share of Trail Mountain was never charged to customers, and is a prior period non-recurring event that should be removed from results.

- The second item was a reserve created in December 2001 associated with a wholesale sales agreement with Enron. When Enron filed for bankruptcy, the Company created a reserve for $1,673,908. In March 2005, a settlement was reached and the reserve reversed.
- The third item was associated with an Accounts Receivable and Doubtful Account reserve created for the California ISO back in Fiscal Year 2001. The ISO defaulted on over $7 million owed to PacifiCorp because of non payment from PG&E and SDG&E. The Company received periodic payments from the California ISO totaling $1,349,615. These payments were recorded as a reduction to the Accounts Receivable balance. In December 2004, the Company reduced the Doubtful Account liability reserve to reflect these payments and credited account 904, understating the Base Period expense.
- The fourth item removes the write-off of an Oregon weatherization reserve for $657,253 which was originally set up in January 2001.
- The final item was to remove a contingent reserve created due to a contract dispute with one of the Company's customers. This dispute was resolved and the reserve of $599,000 was written-off.

Tab 4.6 Out of Period Expense – Four accounting adjustments were made to expense accounts that are non-recurring in nature or related to prior periods. These transactions are removed from the Base Period reducing operating expense

$2.4 million.

- A prior period right-of-way payment of $1,150,923 million was made to the Yellowtail tribe during the Base period.
- A transmission feasibility study for $366,178 was written-off after the project was discontinued.
- The identity management project was cancelled and $1,341,731 was expensed.
- A prior-period legal liability was accrued in 2003 and trued-up to the billed amount during the Base Period crediting expense for $238,000.
- A prior-period property tax refund of $180,000 for the Lloyd Tower Center was recorded during the Base Period.

Tab 4.7 Property Insurance – During the Base Period the insurance reserve was adjusted resulting in an understatement of expense. This adjustment reversed that entry from the Base Period and reflected the incremental changes for premiums and uninsured losses from then to the Test Period.

Tab 4.8 Misc. Rate Base – Amortization Expense Removal – This adjustment removes the amortization of assets that will be complete by the end of the Test Period because they are not recurring expenses. The rate base associated with these assets is removed in Adjustment 8.9 – Misc. Rate Base Adjustment.

Tab 4.10 Additional Power Delivery Programs – This adjustment captures the maintenance and operating expense described in Mr. Darrell Gerrard's testimony.

Tab 4.11-13 Generation Overhaul & OMAG – These adjustments add incremental operation and maintenance expense to the Test Period. Mr. Barry

Cunningham has sponsored testimony supporting the need for these increases.

- Tab 4.11 Generation overhaul costs included in the Base Period were \$22.4 million compared to \$29.7 million in FY 2003 and \$26.4 million in FY 2004. The forecast for FY 2007 is \$38.6 million and \$42.1 million in FY 2008, and increases after that as new plants are brought on line and more extensive work on existing plants is performed.
- Tab 4.12 New Plant Incremental Costs adds O&M for major generation plants that come on-line after the Base Period.
- Tab 4.13 Generation Operation & Maintenance normalizes contracts, materials, and special maintenance from the Base Period to the level forecasted in the Test Period.

Tab 4.14 Solar Photovoltaic Program - This adjustment reflects the estimated annual program costs associated with Pilot Solar Photovoltaic Utility Buy-Down Program that will be co-sponsored by Utah Clean Energy and Utah Power. Approval for this program will be filed under a separate application. This pilot Photo Voltaic project will gather important information on the viability of a solar program funded by participating customers, tax incentives and the Company buy-down. The project will provide technical information on the integration of distributed solar resources into the Utah Power system and demonstrate the ability of solar power to meet growing peak demand. It will also gauge customers' willingness to participate in this program and provide an investment that will both benefit themselves and the utility system. This pilot program has not yet been approved in the state of Utah. PacifiCorp's participation in this program is contingent upon the Commission's approval and the associated costs being included in the Company's revenue requirement.

Tab 4.15 Global Insight's Indices – This tab contains an overview of Global Insight's utility cost indices and a summary of the November 18, 2005 release of these indices.

Q. Please describe how the Company forecasted labor costs for the Test Period.

A. **Tab 4.9 Labor –** The Company forecasts labor costs by adjusting salaries, incentives, benefits, and costs associated with FAS 87 (Pension), FAS 106 (Post Retirement Benefits), and FAS 112 (Long Term Disability). These labor-related expenses were segregated from the other non-labor-related OMAG costs so they could be escalated separately. Page 4.9.1 is a numerical summary starting with Base Period labor costs and adjusting them forward to reflect the Test Period level of expense, with the corresponding adjustment amount for each labor cost. These summaries are followed by the detailed worksheets used to adjust the labor costs forward to the Test Period.

The first step was to annualize salary increases that occurred during the base year. This was done by identifying actual wages by labor group by month and when each labor group received wage increases. Those increases were then applied to wages that were paid prior to the effective date to annualize salary expense. The next step was to repeat that process by applying the wage increases for 2006 and 2007 to the annualized Base Period salaries to forecast the Test Period wages. The Company used union contract agreements to escalate union labor group wages, while increases for non-union and exempt employees were based on budgeted increases. This calculation was performed on pages 4.9.2 through 4.9.7.

Q. Please describe the adjustments the Company made to the Base Period for severance and retirement allowances.

A. During the Base Period, the Company reviewed the corporate organization and functions in an effort to identify potential efficiencies that could be achieved. The result of this initiative was a new organizational proposal called Rebasing. In June 2005, the Company accrued $4 million for severance to be paid to employees whose positions will be eliminated as a result of Rebasing. The Company is proposing that these costs be amortized over a five-year period and has included this amortization as part of the labor costs in this filing and a regulatory asset for the unamortized balance.

Also an accrual to retirement allowance was recorded during the Base period that should have been booked below-the-line. The Company has removed these costs from the filing.

Q. Was an adjustment made to the annual incentive plan payout?

A. Yes. For Fiscal Year 2006, the Company made some modifications to its incentive plan to better align the Company's philosophy of delivering market competitive pay structured in a manner that benefits our customers with safe, adequate and reliable electric service at a reasonable cost. Company goals as structured in the incentive program are now more aligned to service and reliability. The structure of incentive pay is based on 60 percent individual performance with the individual's experience and performance directly related to benefits delivered to the customer. The business unit component, which makes up 30 percent of the incentive compensation, is measured against objectives for the individual employee and team that deliver benefits and improvements to the customer. The last component which makes up 10 percent of the incentive compensation is tied to the Company measure, and it is also directly linked to customer benefits through utility plant availability. To reflect these changes and align incentive pay to budget the Company has reduced its annual incentive plan expense by $12.5 million. The Base Period had $46 million of incentive payments paid to employees. In addition, the Company has removed all the incentive associated with Performance Unit Compensation. This further reduces incentive compensation by $2 million from the actual level in the Base Period. Mr. Erich Wilson’s testimony describes the changes to the incentive plan in further detail.

Q. Were employee pension and benefit costs adjusted in this section also?

A. Yes. Consistent with all other costs, pension and benefits were itemized starting with the Base Period and walked forward to the Test Period. Pension costs have increased $19.7 million and employee benefits have increased $8.9 million from the Base Period to the Test Period. These forecasts were provided by Mr. Rosborough and supported in his testimony.

Q. Does this Tab cover any other items?

A. Yes. Payroll taxes were updated to capture the impact of the changes to employee salaries. This was calculated by applying the FICA tax rates to the net change in salaries and also to reflect the change in the social security cap for the Test

Period.

Q. How were these changes incorporated into the O&M Summary?

A. After adjusting employee salaries and benefits to match the Test Period, these costs were spread back to FERC accounts based on the same percentage that existed in the Base Period. The labor related costs were then added with the non-labor OMAG on pages 4.0.1– 4.0.15 of the summary.

Net Power Costs

Q. How was the Net Power Cost adjustment calculated?

A. The Net Power Cost adjustment normalizes steam and hydro power generation, fuel, purchased power, wheeling expense, and sales for resale in a manner consistent with the contractual terms of the Company's sales and purchase agreements. It also normalizes hydro and weather conditions for the Test Period, as described in Mr. Mark Widmer's testimony.

Q. Please describe the contents of Tab 5 Net Power Cost Summary.

A. Page 5.0 is an overview of the power costs for the Base, Mid and Test Periods. Page 5.1 is a numerical summary for the same periods starting with unadjusted power costs. This is followed by the FERC account and allocation summary and the GRID reports for each period pursuant to the stipulation from Docket No. 04-035-42.

Tab 5.2 James River Royalty & Little Mountain Offset – On January 13, 1993, PacifiCorp executed a contract with James River Paper Company with respect to the Camas mill, later acquired by Georgia Pacific. Under the agreement, PacifiCorp built a steam turbine and is recovering the capital investment over the twenty-year operational term of the agreement as a royalty offset. Included in PacifiCorp's net power costs as purchased power expense are the contract costs of energy for the Camas unit, but GRID does not include an offsetting revenue credit for the capital cost recovery and maintenance cost recovery amounts. Adjustment 5.2 adds this royalty offset to account 456, Other Electric Revenue, for the Base Period and the incremental change to the Test Period.

This adjustment also normalizes the ongoing level of steam revenues related to Little Mountain. Contractually, the steam revenues from the Little Mountain plant are tied to natural gas prices. GRID models the cost of running the Little Mountain plant but does not include the offsetting steam revenues. This adjustment aligns the steam revenues to the gas prices modeled in GRID.

Tab 5.3 Trail Mountain Mine Removal – Regulatory assets were recorded on the Company's books in April 2001 for purposes of amortizing the costs associated with closing the mine through March 2006. The associated amortization expense was excluded from the cost of coal. This adjustment removes all balances from results because the assets will be fully amortized by March 31, 2006.

Tab 5.4 BPA Regional Exchange – This adjustment removes the BPA regional exchange credit from Account 555 because this is a pass-through from BPA to PacifiCorp's eligible residential and small farm customers in Oregon, Washington and Idaho that should not be included in determination of PacifiCorp's revenue requirement.

Depreciation and Amortization Expense

Q. How are the Company's forecasted depreciation and amortization expense for the test year developed in the Report?

A. A detailed worksheet supporting the calculation of the Test Period depreciation and amortization expense, contained in Tab 2, is provided in Tab 6. The Company's approach to forecasting depreciation and amortization expense is explained on page 6.0 of Tab 6. Annual depreciation expense was developed by applying the Company's functional composite depreciation rates, based on the Commission approved rates, to the plant balances for the Test Period, as shown on page 6.1.3. Page 6.1.1 summarizes actual depreciation expense for the actual depreciation expense, normalized Base Period, Mid Period ended September 2006 and the Test Period September 2007. The calculations of the composite rates are summarized on page 6.1.30.

Amortization expense for unadjusted actual, Base Period, Mid Period, and Test Period is summarized on page 6.1.2. Account 404, Intangible Plant Amortization, was forecasted for the Test Period by applying a composite amortization rate to the forecasted intangible plant balances. Amortization of plant acquisitions in Account 406 and unrecovered plant in Account 407 were held constant for the straight-line amortization of these assets. The annual depreciation and amortization expense was added to the accumulated depreciation and amortization reserves to project these balances forward to the Test Period. Retirements were also accounted for, with respect to both the plant additions and accumulated depreciation reserve. Retirements were estimated based on a five-year historical average of retirements which was divided by the plant balance to calculate a retirement rate. This rate was then applied to the plant balance in the Test Period to forecast the Test Period retirements; page 6.1.31 summarizes these rates.

Q. Please explain how the composite depreciation rates were calculated.

A. The composite depreciation rates used in this filing are based on the current Commission authorized rates. These rates identified depreciable electric plant in service by function. Generation facilities were detailed by plant by FERC account; transmission investment was detailed by FERC account; and distribution and general plant were grouped by state by FERC Account. Remaining plant lives were determined and used to calculate the study's depreciation rates. These rates were then applied to the depreciable plant balance to calculate the annual depreciation expense for each sub-category. The authorized composite rates were calculated by dividing the proposed depreciation expense summarized by function by the depreciable plant for that function. For this filing, the Company calculated composite rates by applying Commission authorized rates to Base Period depreciable plant balances. The resulting depreciation expense was then summarized by function and divided by the plant balances including land to calculate the functional composite rates used in this filing. This calculation is summarized on page 6.1.30.

Tab 6.2 Capital Stock Expense – Capital stock expense recorded in FERC Account 214 represents the cost of acquiring equity capital. It comprises payments to investment banks, legal fees, etc. Similar costs are incurred when bonds are issued. Unlike bonds, where these costs are included in the cost of debt, capital stock issuance expenses are not included in the cost of equity calculation. Therefore absent such an adjustment there is no recovery of these issuance costs. Whether the securities are bonds or common equity, customers are the direct beneficiaries of the capital obtained through public financing. As bonds have a finite life, the bond issuance costs are amortized over the life of the bonds. Since common equity shares do not have a specified end date, the appropriate amortization period is not as intuitive. PacifiCorp proposes to amortize the existing balance over a twenty-year period.

Taxes

Q. Please describe the process of forecasting Test Period taxes for use in the results of operations report.

A. The Company has used the same process which has previously been approved by this Commission. For purposes of this discussion, tax expense is separated into the following categories: Schedule M items, Deferred Income Tax Expense, Taxes Other Than Income, and the Renewable Energy Tax Credit. Detail supporting the forecast of the Test Period tax expense is provided in Tab 7.

Tab 7.1 Schedule M's – The Schedule M items from the Base Period were reviewed and any non-recurring items were removed, with the remaining recurring Schedule M items held constant. The Schedule M impact of normalization adjustments and the differences of book versus tax depreciation associated with the capital additions were added to the recurring base year Schedule M items. Pages 7.1 through 7.1.15 detail the Schedule M estimates for the forecasted Test Period.

Tab 7.2 D.I.T. Expense – The Deferred Income Tax Expense from the base year, relating to the Schedule M items removed from the base year, were removed. The Deferred Tax Expense impacts of normalization adjustments were added to the base year recurring deferred tax expense items. The property-related deferred income tax expense was developed from the capital additions, retirements, and depreciation expense for both book and tax, and then added to the deferred tax expense. The deferred income tax summary is shown on pages 7.2 through 7.2.15.

Tab 7.3 Taxes Other Than Income – The forecast for Taxes Other Than Income is shown on page 7.3. Property taxes were forecasted based on revenues, investment, and property valuations for the Test Period. Franchise taxes were updated to match revenues in the Test Period.

Q. How has the Company treated Utah's Gross Receipts Tax in this filing?

A. The Utah Gross Receipts Taxes have been removed from results. Senate Bill 34 proposes tax referendums of which the elimination of the Gross Receipts tax is part of this proposal. If this bill does not pass, the Utah Gross Receipts Taxes should be added back into the Company's revenue requirement.

Current State and Federal Income Tax Expenses – Both current State and Federal Income Tax Expenses were calculated by applying the applicable tax rates to the taxable income. The State Income Tax expense was calculated using the state statutory rates applied to the jurisdictional pre-tax income of the jurisdictions with state income taxes. The result of accumulating those state tax expense calculations is then allocated among the jurisdictions using the Income before Tax ("IBT") factor. The Federal Income Tax Expense ratemaking is calculated using the same methodology that the Company uses in preparing its filed income tax returns. The detail supporting this calculation is contained on pages 2.18 through 2.20.

Tab 7.4 Renewable Energy Tax Credit – The federal government offered an income tax credit for investment in renewable resources placed into service before December 31, 2001. The Company owns a 78.8 percent share of the Foote Creek wind project in Wyoming. The total Company tax credit of $1.6 million is based on PacifiCorp's share of the energy produced at that facility multiplied by the 1.9 cents per kWh tax credit.

Q. Has the Company flowed through to its customers the benefit for the Production Activity Deduction enacted by Congress?

A. Yes. The Company has calculated the Production Activity Deduction as proposed by Edison Electric Institute utilizing their method 1 proposal. Page 7.1.13 of the Schedule M tab 7.1, line 114, shows the Production Activity Deduction for the Test Period.

Q. What is Bonus Depreciation and how is the Bonus Depreciation reflected in this case?

A. Congress enacted the Jobs Creation Act in 2001 to provide incentives to companies to invest dollars in depreciable assets that would be subject to accelerated tax depreciation lives. This was referred to as Bonus Depreciation. Since the Bonus Depreciation had a sunset date of December 2005 for property that was included in Construction Work in Progress ("CWIP") as of December 2004, the majority of the actual Tax Bonus Depreciation has already been recognized in tax expense for both current and deferred expenses prior to this Test Period. However, since Bonus Depreciation is a tax method and timing that is required to be normalized, Utah customers benefit from the higher accumulated deferred tax liability balance in FERC Account 282, which includes the prior recognition of those accelerated tax depreciation benefits.

Rate Base

Q. Please describe how the Company developed the rate base projections used in the Test Period.

A. The detail for rate base for the Test Period is described in Tab 8. The key assumptions used in forecasting the Test Period rate base are summarized on page 8.0. Pages 8.0.1 through 8.0.13 summarize September 2005 unadjusted balances, by FERC account, in the left-hand column and the net rate base changes through September 2007. The column "Test Period Sep 06 – Sep 07 Projected Avg Rate Base" is summarized on pages 2.21 through 2.39 of Tab 2 - Results of Operations. Pages 8.0.14 through 8.0.52 summarize the incremental change by year for each normalization adjustment made to the base year. Detail for these adjustments is contained in Tabs 8.1 through 8.11.

Q. Please describe each of the adjustments to the Base Period rate base balances.

A. **Tab 8.1 Sale of Skookumchuck –** Washington LLC, a limited liability company formed by TransAlta USA Inc. purchased this hydroelectric facility on October 5,

2004. The costs of this facility were removed from the Base Period through this adjustment.

Tab 8.2 Customer Advances – Advances were recorded in the Base Period to a corporate cost center location rather than state-specific locations. This adjustment corrects the allocation of customer deposits by situs assignment of the balance.

Tab 8.3 Sale of East Price Assets – On March 30, 2005, the Company sold a portion of its Price City distribution system. This adjustment removes the plant sold from results. The gain from the sale was treated as a reduction to accumulated depreciation.

Tab 8.4 Glenrock Mine Removal – The closure of the Glenrock mine and the sale of assets, equipment, and supplies occurred in fall of 2005. This adjustment removes those costs from the Base Period thereby eliminating Glenrock from the Test Period.

Tab 8.5 Trapper Mine – PacifiCorp owns a portion of the Trapper Mine, which provides coal to the Craig generating plant. The normalized coal cost of Trapper mine includes all operating and maintenance costs but does not include a return on investment. This adjustment adds the Company’s portion of the Trapper Mine plant investment to rate base. This investment is accounted for on the Company's books in Account 123.1 - Investment in Subsidiary Company. However, Account 123 is not normally a rate base account. This adjustment reflects net plant rather than the actual balance in Account 123 to recognize the depreciation of the investment over time.

Tab 8.6 Jim Bridger Mine – PacifiCorp owns a two-thirds interest in the Bridger

Coal Company, which supplies coal to the Jim Bridger Generating Plant. The Company's investment in Bridger Coal Company is recorded on the books of Pacific Minerals, Inc. ("PMI"). Because of this ownership arrangement, the coal mine investment is not included in electric plant in service. The normalized coal costs for Bridger Coal Company include the operating and maintenance costs of mining, but provide no return on investment. This adjustment is therefore necessary to properly reflect the Bridger Coal Company investment in Test Period rate base.

The Company's share of rate base related to the PMI's investment in the Bridger Coal Mine is projected to increase from $44 million in the Base Period to $123 million in the Test Period. Most of the investment increase relates to Bridger Coal Company's transition to an underground mine. The underground mine provides the least cost supply alternative for the adjacent Bridger Power Plant. Production costs for the surface mine are forecasted to increase significantly due to increased overburden ratios, longer haulage distances, escalating royalties, and diminishing coal quality. The development of the underground mine assures customers a long-term least cost coal supply alternative for the adjacent Bridger Power Plant.

Tab 8.7 PERCO – In 1996, PacifiCorp received an insurance settlement of $33 million for environmental clean-up projects. These funds were transferred to a subsidiary called PacifiCorp Environmental Remediation Company ("PERCO"). This fund balance is amortized or reduced as PERCO expends dollars on clean-up costs. PERCO received an additional $5 million of insurance proceeds plus associated liabilities from PacifiCorp in 1998. This adjustment includes the insurance proceeds in Electric Operations as a reduction to rate base.

Tab 8.8 Hydro Relicensing Settlement Obligations – To comply with Generally Accepted Accounting Principles ("GAAP") accounting, the Company calculated the net present value of future hydro relicensing obligations for Bear River and North Umpqua hydro facilities and recorded the liability with an offsetting asset on Company books. The Company filed accounting applications in each state seeking commission approval for the accounting treatment. After receiving a negative response from one jurisdiction, however, PacifiCorp withdrew its application from all other jurisdictions to avoid multiple regulatory treatments of the same item. The liability was recorded in Account 254, which was not included in base results, leaving the asset and amortization in the base year. This adjustment removes the net present valuation of these obligations and amortizes the cash payments over the remaining life of the license. The net balance is included in rate base.

Tab 8.9 Miscellaneous Rate Base – This adjustment looked at each of the regulatory assets and miscellaneous deferred debits to identify all those that will be fully amortized by September 2007 and removes those investments from rate base. The adjustment also removes deferred credits and asset retirement obligations which will have zero balances by September 2007. The amortization associated with these assets is removed in Adjustment 4.8.

Tab 8.10 Major Plant Additions – To provide a better match between the system infrastructure investment requirements and the load required to serve our customers, the Company has identified capital projects that will be completed by the end of the Test Period. This was done by starting with balances at September 2005 and identifying any investment in construction work in progress. This information was provided to the business units, which were then asked to identify capital expenditures that will be used and useful during the rate effective period. Additions by functional category are summarized, indicating the in-service date and amount by project. The accumulated depreciation reserve was adjusted forward to match the depreciation expense and retirements calculated as described earlier.

Tab 8.11 Accumulated Deferred Income Tax Update – The tax balances for the Base Period were normalized to remove items collected on separate riders and non-regulated balances. The non-property Schedule M-1's for the Test Period were used to develop the forecasted deferred expense and corresponding balance. The property-related deferred income tax balance was developed from the capital additions in Adjustment 8.10 and resulting book and tax depreciation differences.

Q. Does this describe all of the adjustments to rate base for the test year?

A. Yes.

Q. Please describe the rest of the Report.

A. **Tab 9, Rolled-In**, is a re-cast of Tab 2 based on the Rolled-In allocation methodology. This information is being provided pursuant to Commission order from the application of PacifiCorp for an investigation of inter-jurisdictional issues in Docket No. 02-035-04.

Tab 10, Allocation Factors, summarizes the derivation of the jurisdictional allocation factors using the MSP Revised Protocol allocation methodology. These factors are based on the loads provided by Mr. Klein, summarized in Tab 10.2 and the plant balances contained in this Report.

Q. **Would you describe the purpose of Exhibit UP&L___(JTW-2)?**

A. Yes. Pursuant to the stipulation order from Docket No. 04-035-42 and to comply with the filing requirement of Attachment A and Data Request Attachment C the Company has provided three additional Results of Operation reports. They are the Company's Unadjusted results of operation for twelve-months ending September 30, 2005 with both total Company and Utah allocated amounts. The Base Period, which is the normalized results of operation for that same period, again with total Company and Utah allocated. Finally the Mid Period results of operation for the twelve-months ending September 30, 2006.

Q. How is this Exhibit organized?

A. Each period has six tabs, with the exception of the tab identifying the period the other five tabs are titled the same. They are; Tab 1 Summary, Tab 2 Results of Operation, Tab 9 Rolled-In Methodology, Tab 10.1 Allocation Code Factors and Tab 10.2 Demand and Energy Loads. This numbering scheme and the content are consistent with that used in Exhibit UP&L___(JTW-1). The individual tabs for the Unadjusted, Base and Mid Period data are comparisons on a Total Company and Utah allocated basis of those periods to the Test Period results of operation. Tab 1 contains the calculation of the Revised Protocol cap and the Utah allocated results for that period for Revised Protocol and Rolled-In. Tab 2 has the results of operation summary by function and FERC account detail for Total Company and

Utah allocated. Tab 9 is Tab 2 restated based on Rolled-In allocation factors. Tab 10.1 includes the Revised Protocol allocation factors and support for their calculation. Tab 10.2 summarizes the demand and energy for each period which was used for calculation of the factors.

Q. From your analysis what do you conclude about the overall reasonableness of PacifiCorp's forecasted test year in this proceeding?

A. The Test Period that the Company has presented in this case best reflects the conditions in the rate-effective period. Based on this Report, the Company will need this requested rate increase to recover its cost of serving Utah customers and provide a fair and equitable return for shareholders.

Q. Does this conclude your testimony?

A. Yes.