Q. Please state your name and business address.

A. My name is D. Douglas Larson. My business address is One Utah Center, Suite 2300, 201 South Main Street, Salt Lake City, Utah, 84140-2300.

Qualifications

Q. What is your current position at PacifiCorp (the Company) and your previous employment history with the Company?

A. I am currently employed as the Director, Regulatory Policy – Utah, Idaho and Wyoming, in the Regulation Department. I joined the Company in 1981 in the Financial Accounting Department and have held various accounting and regulatory related positions prior to assuming my current position.

Q. What are your responsibilities as Director of Regulatory Policy?

A. My responsibilities include management of regulatory proceedings in Utah, Idaho, and Wyoming. This would include revenue requirement, cost of service, rate design and all other proposed changes to the Company's tariffs. In addition, I have the responsibility for developing regulatory policy on issues that the Commissions must address and making recommendations to management on policy direction.

Q. What is your educational background?

A. I graduated from Brigham Young University in 1982 with a Bachelor of Science Degree in Accounting. In addition to formal education, I have also attended various educational, professional and electric industry related seminars during my career at the Company. I am currently a member of the board of directors of the Intermountain Electric Association, and I am a licensed CPA in the State of Utah.

Purpose of Testimony

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

A. My testimony presents evidence that, based on its normalized and adjusted 1999 results of operations, PacifiCorp is earning an overall return on equity (ROE) in Utah of 4.17 percent. This return is less than the 11 percent ROE currently authorized by the Utah Public Service Commission (the Commission) and less than the 11.5 percent ROE required to provide a fair and equitable return for the Company's shareholders. In support of this conclusion, I introduce and describe the Company's Utah normalized and adjusted Results of Operations Report for the twelve months ended December 31, 1999. The results of operations were prepared in a manner consistent with the Commission's order in Docket 99-035-10 except where noted.

Results of Operations

Q. I show you what has been marked as Exhibit UP&L ___.1 (DDL-1) and ask if you can identify it?

A. Yes. Exhibit UP&L ___.1 (DDL-1) is the Company's Utah Results of Operations Report for the twelve-month test period ended December 31, 1999. I will hereafter refer to this exhibit as the "results" or the "report".

Q. Was the report prepared under your direction?

A. Yes.

Q. Please describe the contents of this report.

A. The results of operations report details revenues, expenses and rate base assigned to the Company's Utah service territory using a rolled-in allocation method. The report provides twelve-month totals for revenues and expenses and expresses rate base as the average of beginning and end-of-year balances. Operating results for the period are presented in terms of both return on rate base and return on equity. The results begin on page 1.0 with a summary of the normalizing adjustments to actual 1999 results. The unadjusted results (Column 1) are a product of allocation factors derived from weather-normalized loads. Column 2 combines and summarizes the effect of Type 1 Adjustments (normalization for out-of-period adjustments and unusual items that occur during the test period) and Type 2 Adjustments (annualization of changes that occurred during the test period) to produce “total adjusted actual results” (Column 3). Column 4 summarizes Type 3 Adjustments (known and measurable items) that are necessary to reach the “total adjusted results” in Column 5. The Type 3 adjustments included in this filing are specifically identified later in my testimony. Column 6 shows the increase in Utah revenues that would be required for the Company to earn a 11.50 percent return on equity from its Utah operations. Column 7 reflects the total adjusted results with this revenue increase included. For comparison purposes, page 1.0 reflects returns on rate base and equity for both the unadjusted and normalized results.

The unadjusted results allocated to Utah using a rolled-in allocation method are detailed under Tab 2. Supporting documentation for the data in Tab 2 is provided under Tabs B1 through B20. The total column of the unadjusted results on page 2.2 corresponds to the actual data recorded in the Company’s accounting records. The normalizing adjustments, which are required to smooth the impact of any unusual events which may have occurred during the test period are identified on page 1.1 and further documented under Tabs 3-8. Tab 9 is blank. The calculation of the rolled-in allocation factors is described under Tab 10.

Q. What conclusions do you draw from the results of operations summary presented on page 2.2?

A. I observe that, as detailed in Column 6 of page 1.0, an overall price increase of $142.2 million (19.1 percent) would be required to increase the Company's earned ROE to 11.50 percent as recommended by Samuel C. Hadaway.

Development of Base Data (Unadjusted Results)

Q. Please explain the process for compiling the base data used in the results.

A. The revenue, expense and rate base data which comprise the unadjusted results of operations is extracted directly from the Company's accounting system and has been summarized under Tabs B1 through B20. The extraction process is largely a matter of downloading information from computer files, supplemented by manual inputs.

Q. Does the unadjusted base data fairly represent the Company's results of operations for 1999?

A. The base data reflects the operating environment and the unique set of circumstances that occurred during calendar year 1999. It is a fair depiction of 1999 actual results, but it is entirely inadequate as a predictor of on-going Company performance. To adequately reflect results on a going-forward basis, it is necessary to make certain adjustments to reflect normal conditions. These adjustments annualize specific events in the test period or normalize unusual events. The following section uses the term “normalizing adjustment” in a generic sense to refer to both annualization of in-period events and normalization of unusual events.

Normalizing Adjustments

Q. Please describe what you mean by normalizing adjustments.

A. In reporting its results of operations, it is the Company’s goal to develop a “typical” test period, free from effects of unusual events. Normalization adjusts for the impact of unusual, non-recurring events. As I indicated earlier, adjustments for unusual items that were booked during the test period are categorized as Type 1 Adjustments in the results of operations report. Normalization also requires an adjustment for the effect of changes that occur part way through the test period. For example, a wage increase that takes place in March should be adjusted to reflect a full twelve-month impact. This type of adjustment is known as annualization and is referred to as a Type 2 Adjustment in the report.

Normalizing adjustments need not be restricted to events that occurred within the test period. PacifiCorp believes that to most effectively match prices with anticipated conditions in the rate-effective period, it is necessary to reflect significant known and measurable out-of-period adjustments in the ratemaking process. Such out-of-period adjustments are referred to as Type 3 in the results of operations report. The following Type 3 adjustments are included in this filing:

- Updating test year revenues to reflect tariffs approved in Docket 99-035-10 that became effective May 25, 2000 and as subsequently modified by the Commission's Order on Reconsideration dated October 6, 2000 (Adjustment 3.2);

- Including revenues from the sale of S02 emission allowances in 2000 (Adjustment 3.4);

- Including revenues from the rental of office space in One Utah Center during 2000 (Adjustment 3.8);

- Normalizing uncollectible accounts expense based on 2000 actual experience (Adjustment 4.6);

- Updating power costs to reflect current market conditions (Adjustment 5.1);

- Reflecting the depreciation accounting adjustment approved in Docket No. 98-2035-03 (Adjustment 6.2), and normalizing depreciation expense and accumulated depreciation to reflect the new rates approved in the same docket, applied to year end depreciable plant balances (Adjustments 6.5 and 6.6); and

- Removing Centralia-related costs and including amortization of the gain from the Centralia sale (Adjustments 8.18 and 8.19).

The related calculations of interest synchronization and cash working capital associated with these adjustments have also been included.

Q. Would you explain each of the 1999 normalizing adjustments?

A. Yes. The report detail under Tabs 3 through 8 supports the summary sheets on pages 1.1 and the normalized returns on page 1.0. Considerable description for each of the adjustments is provided within the exhibit; however, I believe it will be useful to review these explanations at this point in my testimony. In order to understand why the Company believes that the normalized returns on rate base and equity that have been developed are reasonable predictors of future performance, it is necessary to understand the reasons for the underlying adjustments. I will discuss the Revenue adjustments presented in Tab 3 and certain other adjustments in Tab 4 and Tab 8 as described below. The remaining adjustments in Tabs 4-8 will be addressed by other Company witnesses. For discussion purposes the adjustments will be presented in pre-tax dollars, where applicable. The income tax effect of each adjustment is calculated and reflected on the summary page following each tab.

Q. Who are the Company witnesses that describe the other normalizing adjustments in Tabs 4-8?

A. Tab 4 (O&M expense) contains 22 individual adjustments. I address Adjustments 4.1 through 4.5, 4.7, 4.8, 4.10, 4.13, 4.14 and 4.18. Mr. Daniel Peterson presents Adjustments 4.6, 4.17 and 4.19 through 4.22. Mr. Ted Weston addresses Adjustments 4.9, 4.11, 4.12, 4.15 and 4.16.

The Net Power Cost adjustments in Tab 5 normalize revenues and expenses in a manner consistent with normalized operation of production facilities described in Mr. Widmer's testimony. The normalized net power cost developed and explained in Mr. Widmer's testimony is reflected in Adjustment 5.1. Mr. Weston explains how net power cost is reflected in results and also sponsors associated Adjustment 5.2 related to an incremental coal cost discount. Mr. Weston also sponsors Adjustment 5.4 related to wheeling revenue. Mr. Widmer sponsors Adjustments 5.3 and 5.5 related to sales for resale.

The adjustments in Tab 6 (Depreciation and Amortization) and Tab 7 (Tax Adjustments) are explained by Mr. Peterson.

Tab 8 (Rate Base) consists of 20 individual adjustments. I will address Adjustments 8.1 through 8.8, 8.12, 8.13 and 8.20. Mr. Peterson will present

Adjustments 8.9, 8.14, 8.15 and 8.16. Mr. Weston will address Adjustments 8.10, 8.11, 8.17, 8.18 and 8.19.

Q. Please explain the revenue adjustments summarized under Tab 3, page 3.0.

A. **Weather Normalization** (Adjustment 3.1) – Weather normalization reflects weather or temperature patterns that were measurably different than normal, as defined by 30-year historical studies by the National Oceanic & Atmospheric Administration. Only residential and commercial sales are considered weather sensitive. Industrial sales are more sensitive to specific economic factors. In its order in Docket No. 99-035-10, the Commission required the Company to provide a report documenting its recommendations for the maintenance of, or modifications to, the weather normalization procedure. While progress has been made on the studies necessary for this report, they are not yet complete. Therefore, this adjustment reflects the same normalization procedures used in the 99-035-10 case. Adjustment 3.1 increases 1999 Utah residential revenues by $667,000 and decreases commercial revenues by $455,000.

Effective Price Change (Adjustment 3.2) – The price change adjustment annualizes existing contract and tariff changes to reflect a full year of revenues based on the new rates. The annualization is done by comparing actual revenues in the test period to the annualized revenues calculated by applying the new rates in the contracts and tariffs to current energy usage. Adjustment 3.2 results in a net increase of $1,074,709 in Utah's allocated share of special contract revenues. This adjustment also reduces revenues to annualize the impact of the Commission-ordered price reduction in Docket No. 97-035-01 and increases revenues to reflect the recent Commission-ordered increase in Utah residential, commercial and industrial tariffs in Docket No. 99-035-10.

Revenue Normalizing (Adjustment 3.3) – This adjustment normalizes 1999 revenues by removing out of period adjustments. The adjustment increases Utah situs revenues by $1,371,491 and decreases its allocated share of revenues from system contracts by $291,401.

SO2 Emission Allowances (Adjustment 3.4) – As I indicated earlier, the Company has included all emission allowance sales made through November 2000, utilizing a four-year amortization of the gain from these sales as ordered in Docket 97-035-01. Adjustment 3.4 increases Utah allocated revenues by $3,775,048, reduces rate base by $4,083,176 and reflects deferred tax impacts.

Unbilled Revenue (Adjustment 3.5) – This adjustment corrects an error in the unbilled revenue calculation that occurred in 1998 but was not discovered until 1999. Docket 99-035-10 increased Utah's 1998 revenues $6,109,000 for the recognition of revenues in 1999 that related to 1998. Adjustment 3.5 reduces 1999 Utah revenues by $6,109,000 to remove the amount applicable to the prior period.

Pilot Revenue (Adjustment 3.6) – During 1999, the Company received revenues for sales of energy into the pilot customer choice programs of both Puget Sound Power & Light Company in Washington and Portland General Electric in Oregon. This adjustment reassigns those revenues from Washington and Oregon to a system-wide allocation that is consistent with the allocation of the associated costs, thereby increasing Utah revenues by $215,118.

USBR/UKRB Discount (Adjustment 3.7) – Under long existing contracts with PacifiCorp, the U.S. Bureau of Reclamation (USBR) and the Klamath Basin Water Users' Protective Association (UKRB) receive a reduced price compared to fully tariffed customers. The contracts preserve the Company's interests in three hydro projects on the Klamath River. The reduced irrigation revenues have been treated for accounting purposes as situs revenues of Oregon and California. However, since all customers share in the benefits of the hydro production from these plants, it is appropriate that the costs be shared in the same way. This adjustment treats the discount as a cost of PacifiCorp's entire hydro system rather than as a state specific cost, thereby increasing Utah's allocated share of hydro expense by $2,639,552.

Rental Revenues (Adjustment 3.8) – This adjustment annualizes sublease revenue for the second floor of the Oregon Square Building for 1999 and for the sixth and seventh floors of One Utah Center for 2000. Adjustment 3.8 increases Utah allocated revenues by $328,429.

Guaranteed Merger Credit (Adjustment 3.9) – In December 1999 the Company recognized for book purposes the merger credit liability. Merger Credits are not included in the revenue requirement calculation. Adjustment 3.9 removes that credit from results which increases Utah revenues by $24,000,000.

Reversal of Revenue Adjustments (Adjustment 3.10) – This adjustment reverses the effect of an accounting entry made to reflect a billing dispute that resulted in the write-off of $9 million. Adjustment 3.10 increases Utah allocated revenues by $3,278,134.

DSM Revenue Adjustment (Adjustment 3.11) – This adjustment corrects the allocation of Oregon Deferred DSM revenues that were erroneously allocated system-wide. Adjustment 3.11 reduces Utah allocated revenues by $473,508.

Customer Reclassification (Adjustment 3.12) – This adjustment reclassifies the revenues from firm sales to an Idaho firm customer that were inappropriately allocated system-wide. Adjustment 3.12 reduces Utah allocated revenues by $531,800.

Tariff 300 Revenue Normalized (Adjustment 3.13) – In an order dated September 13, 1999 in Docket No. 97-035-01 the Commission approved changes to Tariff Schedule 300 customer charges, including charges for interest, returned check charges and miscellaneous service revenues. This adjustment annualizes the effect of these changes as though they had been in effect for the entire year. Adjustment 3.13 reduces Utah revenues by $256,412.

Q. Please explain O&M adjustments 4.1 through 4.5, 4.7, 4.8, 4.10, 4.13, 4.14 and 4.18 in Tab 4.

A. **FAS 106 Deferred Charges** (Adjustment 4.1) – FAS 106 established accounting as well as disclosure standards for employers with post-retirement benefit plans. It requires that post-retirement benefit expenses be recognized while employees are actively employed and earning these benefits rather than after they have retired. Prior to this new accounting standard, PacifiCorp was accounting for these benefits on a pay-as-you-go (i.e. cash) basis. In Docket Nos. 20000-ET-92-50 and 20001-ET-92-22, the Wyoming Public Service Commission (WPSC) authorized an accrual method of accounting for FAS 106 along with deferral treatment for the difference between accrual and pay-as-you-go for no more than three years and then amortization of the balance over the next seven years. PacifiCorp deferred the difference between the two methods of accounting for these costs January 1993 through December 1995; during that time $9.8 million was deferred as Wyoming's portion of FAS 106 costs. In 1996 the Company stopped deferring this difference and began amortization of the accumulated balance. The deferred costs are now being amortized to Account 929, which is allocated system wide on a System Overhead (SO) allocation factor. Adjustment 4.1 is necessary to correct the allocation of these costs, which should be directly assigned to Wyoming. The Wyoming deferred balance will be completely amortized by the end of 2002. This adjustment was approved in Docket 97-035-10 and decreases Utah expense by $519,090.

FICA Adjustment (Adjustment 4.2) – Adjustment 4.5 annualizes general wage increases effective during 1999. This adjustment reflects the FICA tax increase associated with the annualized General Wage Increase (Adjustments 4.5). Adjustment 4.2 increases Utah tax expense by $32,555.

Early Retirement Adjustment (Adjustment 4.3) – In 1998 PacifiCorp announced an early retirement program, targeted primarily at reducing the number of corporate staff and administrative support personnel. A total of 961 qualified employees opted to take advantage of this program. Those qualified for early retirement were able to begin leaving in April 1998. Adjustment 4.3 amortizes the expense of the program over five years as authorized by the Commission's order in Docket No. 99-035-10, increasing Utah expense by $7,974,736, increasing rate base by $16,586,434 and reflecting deferred tax effects.

Remove LTIP (Adjustment 4.4) – This adjustment removes the costs of the Company's long-term executive incentive compensation plan, LTIP, from the test period in accordance with the Commission's order in Docket No. 97-035-10. Adjustment 4.4 decreases Utah's expense by $853,417.

Annualized - General Wage Increase (Adjustment 4.5) – PacifiCorp has several labor groups, each with different effective contract renewal dates. The Company negotiates wage increases with each of these groups throughout the year. Adjustment 4.5 annualizes the effective wage increases received during 1999 for labor charged to operation and maintenance accounts. This annualization was calculated by identifying actual wages for each labor group, by month and then applying the negotiated wage increase to the wages for the months prior to the effective contract date. This adjustment restates expense as though the wage increase was effective for the entire test period. No adjustment to rate base was made to reflect the increase in capitalized wages. Adjustment 4.5 increases Utah's allocated share of operating and maintenance expense by $506,122.

Pension Adjustment (Adjustment 4.7) – In 1997 PacifiCorp adopted the method of recognizing pension expense mandated by FAS 87 for financial reporting purposes, resulting in the write-off of the pension regulatory asset. This adjustment reflects the second year of a ten-year amortization of the pension regulatory asset and is consistent with the Commission's order in Docket 99-035-

10. Adjustment 4.7 increases Utah's allocated share of pension expense by $3,164,747 and reflects the appropriate deferred income tax effects.

Allocation of CSS Costs (Adjustment 4.8) – During 1999 the ongoing support and miscellaneous enhancement costs for the Company's Customer Service System (CSS) were charged to administrative and general expense accounts that are allocated on the System Overhead (SO) factor. This adjustment reverses the allocation of CSS costs on the SO factor, removes one third per Commission order in Docket 99-035-10 and properly allocates the remaining costs on the Customer Number (CN) factor. Adjustment 4.8 reduces Utah allocated expense by $198,182.

California Wind Removal (Adjustment 4.10) – During 1999 some miscellaneous charges associated with a California wind project were inadvertently charged above the line. Adjustment 4.10 removes those costs from results reducing Utah expense by $9,899.

Implement Customer Service Standards (Adjustment 4.13) – One of the Company's commitments in connection with the ScottishPower merger was to implement customer service standards in Utah at no additional cost to customers. This adjustment removes costs related to the implementation of these standards from the 1999 test year. Adjustment 4.13 reduces Utah allocated expense by $319,958 and reduces Utah allocated rate base by $106,896.

PacifiCorp Trans Adjustment (Adjustment 4.14) – This adjusts the 1999 corporate aircraft residual to reflect the percent of residual allowed in electric operations in Docket No. 99-035-10 based on nautical miles. In addition the gain on the sale of aircraft number 206PC which was captured in the previously cited case is removed. The net impact of adjustment 4.14 is to increase Utah expense by $97,603.

Costs Triggered by Merger (Adjustment 4.18) – This adjustment amortizes 1999 test period expense costs that were not merger costs, but that were triggered by the merger. These costs relate to transition planning to achieve electric operation efficiencies or the acceleration of stock plans due to the merger. The merger-triggered costs are being amortized over three years for ratemaking purposes. Adjustment 4.18 reduces Utah allocated expense by $2,550,146 and increases Utah allocated rate base by $1,275,073 to reflect the un-amortized balance of these costs.

Q. Please explain Rate Base adjustments 8.1 through 8.8, 8.12, 8.13 and 8.20 in Tab 8.

A. **Environmental Settlement** (Adjustment 8.1) – 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). In 1998 PERCO received an additional $5 million of insurance proceeds. This adjustment is necessary to reflect the insurance proceeds in the test period as a reduction to rate base. The rate base credit will be reduced or amortized over time as PERCO expends dollars on clean-up costs. Adjustment 8.1 reduces Utah allocated rate base by $11,422,410.

CSS Disallowance (Adjustment 8.2) - This adjustment removes one-third of the Company's investment in its customer service system (CSS) software from the

1999 test period, consistent with the Stipulation approved by the Commission in its order dated February 26, 1999 in Docket No. 97-035-01. Adjustment 8.2 decreases Utah allocated rate base by $8,197,430 and expense by $1,092,991.

Trapper Mine Rate Base (Adjustment 8.3) – PacifiCorp owns a 21.47 percent interest in the Trapper Mine, which provides coal to the Craig generating plant. The normalized coal cost for Trapper includes all operating and maintenance costs but does not include a return on investment. This adjustment is necessary to add the Company-owned portion of Trapper Mine plant investment to rate base, since this investment is recorded in Account 123.1 – Investment in Subsidiary Company. Account 123 is not normally a rate base account. The adjustment reflects net plant rather than the actual balance in Account 123 to recognize the depreciation of the investment over time. Adjustment 8.3 increases Utah allocated rate base by $1,985,371.

Bridger Coal Co. Rate Base (Adjustment 8.4) – 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), a wholly-owned subsidiary. 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. Therefore, this adjustment is necessary to properly reflect the Bridger Coal Company plant investment in test period rate base. Adjustment 8.4 increases Utah allocated rate base by $16,933,403.

Dave Johnston (Glenrock Coal Co.) Mine Closure (Adjustment 8.5) – PacifiCorp is aggressively pursuing ways to lower fuel costs at all of its facilities. Mine stripping ratios at the Dave Johnston mine have made it difficult to compete with coal from the Powder River Basin. In the past, rail transportation constraints have made the continued operation of the mine the most economic alternative. However, PacifiCorp was able to negotiate a new transportation contract that made purchasing market coal the least cost option. As a result the Dave Johnston mine was closed in October 1999. This closure is ten years earlier than the previously estimated mine life. Early closure means that mine reclamation cost and depreciation expense were under-accrued. Therefore, in December 1997 PacifiCorp made an accrual for reclamation, depreciation and employee severance costs to bring the accumulated balances in these accounts to the proper level by the date of mine closure. This issue was presented in Docket No. 97-035-01 and again in Docket No. 99-035-10. In Docket No. 99-035-10, the Commission deferred to the future recovery of the mine write-down but allowed a five-year amortization of the $33 million reclamation expense incurred at the time of the mine write-down to begin in 1998. This adjustment returns the mine asset to rate base, takes the first year of amortization expense on the mine assets and the second year of a five-year amortization of reclamation costs. It is important to note that the decision to close Dave Johnston mine has resulted in savings in 1999 fuel costs as a result of the use of Powder River Basin coal. A full year of the fuel savings from these Powder River Basin coal purchases is reflected in the Net Power Cost Study. The Company is requesting the Commission to allow a five-year recovery of the assets written-off, beginning in this filing. Adjustment 8.5 increases Utah allocated expense by $4,677,883, adds the remaining unamortized balance of $17,624,861 to rate base and appropriately reflects deferred tax effects.

Computer Mainframe Write-Down (Adjustment 8.6) – The Company removed one of the mainframes from service in January 1998. In Docket No. 99-035-10 the Commission ordered a five-year amortization of these costs. Adjustment 8.6 reflects the second year of amortization increasing Utah expenses by $885,061, increases rate base by $3,097,714 and reflects deferred tax effects.

SAP Rate Base (Adjustment 8.7) – This adjustment is necessary to annualize the cost of the SAP system added to rate base during 1999. Adjustment 8.7 increases expense by $1,704,275, increases rate base by $9,647,152 and reflects deferred tax effects.

Software Write-down (Adjustment 8.8) – The Company's new SAP (Systems Applications and Products) software product replaced several outdated finance, human resources, materials, work management, and project administration software systems. With the installation of new systems, the existing systems became obsolete. In order to complete the amortization of the old software costs, an adjustment was necessary. The remaining unamortized balance was written off in 1997. In Docket No. 99-035-10 the Commission ruled that "SAP was not fully implemented during the test year so expected productivity enhancements have not yet occurred", and the write-off was added back to rate base. SAP was used throughout 1999, and adjustment 8.8 reflects the first year of a three year amortization, thus increasing Utah allocated software amortization expense by $843,282, adds the unamortized balance of $2,108,205 to rate base and reflects deferred tax effects.

QF Contract Buyouts (Adjustment 8.12) – Under the 1978 Public Utilities Regulatory Policy Act (PURPA), investor-owned utilities were required to purchase power from qualifying generation facilities that could provide power at or below the utility's avoided cost. These contracts, which have been approved by state regulatory commissions, are known as Qualifying Facilities (QF) contracts. During 1999 the Company negotiated a buy-out of the Bogus Creek QF contract at less than the present value of the future required payments under the contract. This buy-out is being amortized over the remaining life of the contract. Rate base is being adjusted to reflect the buyout as if it had occurred at January 1, 1999. In 1998, PacifiCorp negotiated a buyout of the Lacomb Irrigation QF contract that is being amortized over the remaining life of that contract. This adjustment also removes prior period amortization expense related to the Lacomb contract, annualizes the amortization expense and restates the beginning balances for the contracts to reflect the appropriate amortization. Adjustment 8.12 decreases Utah allocated operating expense by $9,016 and increases rate base by $287,134.

Remove SERP Reserve (Adjustment 8.13) -- Supplemental Executive Retirement Plan (SERP) expense is accrued each year in accordance with the actuarial report. The excess of this accrual over payouts under the plan is recorded as a liability. The SERP reserve liability account was not identified as a rate base deduction in the Company's unadjusted results of operations. Adjustment 8.13 includes the SERP reserve as a rate base deduction to Utah of $5,983,799.

Amortization of Y2K Cost (Adjustment 8.20) – The Company has incurred expense for the last three years to ensure that all the Company's computer hardware and software systems were Y2K compliant. The Commission ordered a three-year amortization of those costs in Docket No. 99-035-10. Adjustment 8.20 reverses costs incurred during 1999 and replaces those with the second year amortization of 1998 and the first year of 1999. This adjustment reduces Utah allocated expense by $508,111 and increases rate base by $4,121,222.

Changes from Docket No. 99-035-10

Q. You indicated earlier that this filing was prepared in accordance with the provisions of the Commission's order in Docket No. 99-035-10 with certain exceptions. Please describe these differences.

A. This filing is consistent with the findings of the most recent Commission order with the exception of seven issues that I have identified below. For each of these issues the Company is asking the Commission to adopt a different position than it adopted in Docket No. 99-035-10. Those issues are: (1) the allocation of Account 903 expenses; (2) the development of the System Generation (SG) factor; (3) the amortization of system software write-downs; (4) the amortization of the Glenrock Mine write-off, (5) the normalization of bad debt expense; (6) the inclusion of Condit Hydro Plant removal costs in depreciation expense; and (7) the inclusion of Bridger Coal Company Accounts Receivable.

Q. Please explain how the filing in the proceeding departs from the Commission's previous order with respect to the seven issues you have identified.

A. I will address each of these issues individually.

Account 903 Expense Allocation

In the Company's last two general rate case filings before this Commission, the Division of Public Utilities (DPU) has raised concerns about the appropriate allocation factor that should be used to allocate costs in Customer Services Account 903. In Docket 99-035-10 the Commission ordered the DPU and the Company to work together to determine the appropriate allocation factor for Account 903 costs before the next rate case. Since the date of the order, Company representatives have met with the DPU, and an approach for reviewing this issue has been discussed. However, this review process has not been completed because both Division and Company staff assigned to the project have been occupied by other pressing issues. Because test period data indicates a relationship between the number of customers served and the incurrence of customer expense, the Company has used the CN factor to allocate Account 903 costs in this filing. For example, current data shows that the number of phone calls to the Business Centers that originated in Utah continues to closely track the relative number of customers in Utah, as represented by the CN factor. Use of the CN factor for Account 903 and other customer accounts provides an overall level of Utah customer service expense that is cost-causation based and consistent with prior years' amounts.

Calculation of the System Generation (SG) Factor

In its order in Docket No. 99-035-10 the Commission observed that the SG factor is the weighted average of the System Capacity (SC) factor, a measure of peak load responsibility, and the System Energy (SE) factor, a measure of annual usage. The Commission explained that the SC factor is constructed by identifying the hour when the combined firm retail loads of all jurisdictions attain a maximum for every month of the test year. Each jurisdiction's load is measured in megawatts at the identified peak hour of the month. The monthly peak loads for each jurisdiction are then added together to obtain an annual jurisdiction figure. The SC factor is the ratio of a jurisdiction's annual figure to the total for all jurisdictions.

In this same docket, the DPU argued that the SC factor is relatively sensitive to changes in the time of day used to identify the monthly peak. The Division observed that in 1998 all four monthly system winter peaks occurred during the evening, which was a departure from timing of winter peaks in previous years. The Division argued that the calculation of the SC factor in the manner described by the Commission produced an abnormal result in 1998 because of this change in the timing of these monthly peaks. On this basis the DPU proposed to set aside the Commission-approved method of calculating the SG factor and substituting a "normalized" factor based on the 4% average growth rate in the SC factor from 1992 to 1996. The Company opposed the Division's adjustment, explaining that the 1998 SC and SG factors were consistent with general load growth trends during 1992-1998. Believing that it lacked an appropriate explanation for the deviation of the 1998 SC factor from a 1993 to 1997 trend line, the Commission adopted the DPU adjustment.

PacifiCorp believes that information from the 1999 test period shows the lack of basis for the Division's "normalizing" of the SC factor. In 1999 the Company experienced two winter evening peaks, down from the four evening peaks experienced in 1998 and consistent with the two evening peaks seen in 1997. However, the SC factor calculated by the method described above by the Commission increased from 34.95 percent in 1998 to 36.30 percent in 1999. Thus, we see that the SC factor increased from 1997 to 1998 when the winter evening peaks increased from two to four and increased again from 1998 to 1999 when the winter evening peaks decreased from four to two. Contrary to the DPU's assertion in the 99-035-10 case, it is now clear that the increase in the SC factor is not due to sensitivity to changes in the time of day used to identify the monthly peak. Rather, as the Company has maintained, the growth in the SC and SG factors has been and continues to be driven by the high load growth on the Utah system, relative to the load growth in the Company's other retail jurisdictions. This explanation is entirely consistent with the construction of the SC factor as explained by the Commission. The fact is that during 1999 Utah grew by 3.8 percent, which is far more than any other jurisdiction. Indeed, since 1989 the Utah jurisdiction has outgrown all other jurisdictions by more than a two-to-one margin. Based on this continued pattern of load growth, the Company has calculated the SG factor used in this filing in accordance with this Commission's authorized method described in Docket 97-035-04. It is important to note that the Company has not updated the loads used in this filing to reflect 2000 usage levels, resulting in allocation factors that are already conservative from a Utah perspective.

Software Write-offs

In Docket No. 99-035-10 the Commission found that the Company's "legacy" software (replaced by SAP) was still used and useful during 1998 and ordered it to be added back to rate base until a better match of cost and benefits could be achieved. SAP was the Company's accounting system for all of 1999. In addition customers have benefited from lower labor costs through 1999 from the early retirement program, a part of which was enabled by SAP. Therefore, the Company began a three-year amortization of these obsolete software costs, beginning in 1999.

Glenrock Mine Cost Write-off

The Commission ruled in Docket 99-035-10 that since reclamation work at the Glenrock Mine had begun during the 1998 test period, the Company would be allowed to begin amortization of those reclamation costs over a five-year period. However, the Commission ruled that the Company could not begin amortization of the rate base in that case because the "primary savings" associated with the purchase of Powder River Basin coal did not occur in 1998. The current filing continues with the second year of reclamation amortization approved by the Commission and begins the first year of rate base amortization. The Company believes this is appropriate since the Glenrock mine was closed in October of

1999 and fuel costs have been normalized to reflect a full year of the Powder River Basin contract coal prices.

Normalization of Bad Debt Expense

In Docket No. 99-035-10 the Commission found that actual 1998 uncollectible expense was problematic and chose to normalize bad debts by using a three-year 1994 through 1996 average. However, in this proceeding the Company has included bad debt expense at a level consistent with 2000 actual experience (11 months actual, 1 month estimated). In recent years the Company has made a concerted effort to reduce uncollectible accounts, and in 2000 bad debt expense has dropped to a level consistent with the 1994-1996 average. Since recent experience is now consistent with benchmark levels, the Company believes it is appropriate to put aside the historical averaging approach and use the best available current data in determining test period uncollectible expense.

Condit Hydro Plant Removal Cost

In Docket No. 99-035-10 the Commission found that additional depreciation expense accrued in 1998 for the Condit dam removal should be removed from the test period because the removal agreement was signed after the test year and had not been approved. However, the removal agreement was signed and the FERC approval process was initiated in 1999. In addition, on April 1, 2000, new depreciation rates became effective that continue the recovery of Condit dam removal costs. Because the dam removal agreement has been formalized and the recovery of dam removal costs has begun through Commission-approved depreciation rates, the Company's filing makes no adjustment to 1999 Condit dam removal costs.

Bridger Coal Company Accounts Receivable

In its order in Docket No. 99-035-10 the Commission adopted an adjustment proposed by the Committee of Consumer Services to eliminate the Bridger Accounts Receivable from rate base. This adjustment was opposed by both the Company and the DPU. In fact, the accounts payable balance for Bridger Coal Company is included in the updated lead-lag study (December 1998) used to calculate cash working capital in this case. The Bridger Coal Company receivable balance must, therefore, be included in ratebase to offset the lower cash working capital that results from including Bridger's payable balance. For this reason the Company has included the Bridger Coal Company accounts receivable balance in the test period rate base.

Loads

Q. Have loads been updated to 2000 levels?

A. No. As previously mentioned, the Company has only made price changes to reflect current tariffs or market prices. No adjustment was made to loads for revenues, allocation factors or power costs.

Conclusion

Q. In summary what conclusion does your testimony support?

A. My testimony, along with that of Messrs. Peterson and Weston, demonstrates that PacifiCorp's normalized earnings in its Utah service territory supports a price increase of $142.2 million (19.1 percent).

Q. Does this conclude your testimony?

A. Yes.