BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR APPROVAL OF ITS PROPOSED ELECTRIC RATE SCHEDULES & ELECTRIC SERVICE REGULATIONS	))))))))	Docket No. 03-2035-02 PHASE II

JULY 2003

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IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR APPROVAL OF ITS PROPOSED ELECTRIC RATE SCHEDULES & ELECTRIC SERVICE REGULATIONS	))))))))	Docket No. 03-2035-02 DIRECT TESTIMONY OF D. DOUGLAS LARSON

JULY 2003

Q. Please state your name, business address and present position with PacifiCorp dba Utah Power & Light Company (the Company).

A. My name is D. Douglas Larson. My business address is Suite 2300, 201 South Main Street, Salt Lake City, Utah, 84111. My present position is Vice President, Regulation.

Qualifications

Q. Briefly describe your educational and professional background.

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

A. I am responsible for the development and execution of the Company's regulatory policy across the six states in which the Company does business. This includes management of regulatory proceeding in each of the six states, including revenue requirement, cost-of-service, rate design and all other proposed changes to the Company's tariffs. In addition, I have responsibility for developing regulatory policy on issues that the commissions must address and making recommendations to management on policy decisions.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of the Company's case and to provide the context of this rate case for other witnesses who will testify regarding our specific proposals. I will discuss the Company's main objectives in this case. Finally, I introduce the Company witnesses and briefly discuss the issues they address.

Q. Please discuss the filing requirements of this case.

A. The filing requirements of this case were determined as part of a stipulation approved by the Public Service Commission in its May 6, 2003, Order affirming a bench order approval of April 16, 2003. The stipulation set out a defined process and timetable for filing the major elements of this rate case. Following the Commission's May 6 Order, the Company initiated the General Rate Case process with an initial filing on May 15, 2003. This initial filing set out the total capped increase that the Company could request as part of the General Rate Case proceedings. The Company also filed its rate of return and capital structure testimony and embedded cost of debt and preferred stock testimony. Under the terms of the stipulation, the total capped increase request was to be up-dated by a detailed revenue requirement filing on July 31, 2003. Class cost of service, rate design and rate spread testimony is to be filed on September 15, 2003.

Q. What is the cap on the increase in this case?

A As noted in our May 15 filing, the total increase that the Company can request or receive as a result of these General Rate Case proceedings is $125 million.

Q. What actual rate increase is the Company requesting?

A The Company is at this time requesting a rate increase of $125 million. However, in accordance with the stipulation, the Company will file known and measurable updates to its requested increase on or before October 15, 2003. These updates will take account of any known or measurable changes that take place on or before January 1, 2004.

Q. Please explain why the Company is filing for a requested increase at this time.

A. The filing promotes PacifiCorp's key goals of delivering safe, reliable electric service, providing excellent customer service and maintaining reasonable, competitive prices. To ensure resources to permit PacifiCorp to operate as a responsive, high quality utility, PacifiCorp seeks recovery of costs in areas subject to increases since the Company filed its last General Rate Case in September 2000. Although the magnitude of the increase is by no means insignificant, the Company has been able to moderate the rate request through aggressive cost control initiatives and sizeable reductions in net power costs. Even with the price increases proposed in this case, PacifiCorp's service remains an exceptional value when measured against other utilities within the state, across the West, and throughout the nation. Essentially, this filing promotes the Company goal of being allowed to earn an allowed rate of return on prudent investment.

Q. How does the rate relief requested here compare with the rates determined in the September 2000 General Rate Case?

A. The current request reflects a number of changes since the filing of the 2000

General Rate Case. The major factor has been the ongoing investment required to support continued customer and load growth in Utah. Since the last rate case filing, the Gadsby Peakers have been added to rate base, there has been ongoing investment in existing plant, and there has been significant investment to distribution systems along the fast growing Wasatch front area. This investment level will continue as we strengthen a rapidly growing system.

These additions to rate base show our commitment to invest to support growth in Utah. As discussed in detail in Mr. Davis's testimony, Utah is PacifiCorp's fastest growing state and it is essential that the Company invests to support this growth.

In addition, Utah's share of the total PacifiCorp system has increased from around 37.0 percent in September 2000 to 39.2 percent as of March 2003. Under the rolled-in allocation method previously adopted by this Commission, this means that Utah picks up a higher proportion of system operating costs.

Q. Apart from system growth and investment are there other reasons for the requested revenue increase in this Rate Case Filing?

A. Yes. In addition, to increased costs relating to the operation and development of the Utah system, the Company is also facing cost increases to its pension and insurance costs as explained in the testimony of Mr. Rosborough and Ms. Cartwright. These increases are driven by external conditions, as discussed later in my testimony and are not unique to PacifiCorp. The Company is also requesting an increase in return on equity from the current 11.00 percent rate to 11.50 percent. As Dr. Hadaway explains in his testimony, this is a reasonable point value for PacifiCorp's cost of equity. Finally, amortization of regulatory assets and transition plan expenses ordered in previous rate cases also increase the revenue requirement.

At the same time, the Company is proposing to reduce normalized power costs from $590 million in the September 2000 General Rate Case to about $522 million system-wide, which represents a $26.1 million reduction in power costs for Utah customers. As discussed in Mr. Widmer's testimony, much of this reduction is due to reduced loads elsewhere in the PacifiCorp system. This reduction in total system loads has created a position where PacifiCorp has been able to reduce its need to purchase additional power. While these net power costs have been reduced, these have been offset by Utah's increase in its share of the total PacifiCorp system.

Q. What are the Company's specific objectives in filing this rate case?

A. The Company's objectives are to: (1) recover cost increases driven by the increased load growth in Utah, (2) recover cost increases driven by external conditions; (3) improve financial strength to maintain infrastructure and ensure reliable service, including an increase in the return on equity to reflect the increased risks associated with operating in Utah; and (4) reset and reduce power costs. In my testimony, I address each of these objectives separately.

Increased Load Growth in Utah

Q. Please explain what you mean by "cost increases driven by the increased load growth in Utah."

A. Since the last rate case filed in Utah, the Company has seen continued load growth in Utah. This is explained in more detail in the testimony of Mr. Davis. Essentially the Company continues to see both a growth in customer numbers and a growth in the amount of energy that customers are using on average. This requires the Company to invest in its systems to ensure that they are able to support this increased demand.

In addition, as supported by Mr. Davis's testimony and exhibits, over the ten year period from 1993 through 2002 while Utah's energy usage has grown about 40 percent, its contribution to the summer peak has grown by more than 70 percent. This creates a situation where the network has to be expanded at a rate that exceeds the underlying growth in energy sales.

The Company is also seeing the SG allocation factor for Utah increase by around 2.2 percent. This means that Utah is using a greater percentage of the total PacifiCorp system and therefore is picking up a higher allocation of overall costs. As noted by Mr. Davis, the extent of this growth has been magnified as a result of the economic conditions in other states.

Externally Influenced Costs

Q. Please elaborate on what you mean by "cost increases driven by external conditions."

A. Recently, the Company has seen dramatic increases in insurance costs, pension costs, and costs related to health insurance. External factors, such as the downturn in the financial markets and the impacts arising from the events of September 11, 2001, are driving the increases in these costs. Although the Company has mitigated some of the impact of those increases with internal cost control initiatives, those externally driven costs are largely unavoidable. Rising costs in these areas are not unique to PacifiCorp or even to the utility sector. The scale of the Company's operations means that personnel-related costs such as pensions and health benefits are significant in terms of the Company's overall costs.

Q. How can you justify asking your customers to pay higher rates?

A. Even with this requested increase, customer prices would be lower than they were in 1985. Taking inflation into account, the proposed prices will be significantly lower, in real terms, than in 1985. This price stability has created a situation of stable and, at times, decreasing power prices, which has undoubtedly been good for the development of the state of Utah. That being said, healthy utilities are critical for economic growth and stability in the state. At this time, it is essential that PacifiCorp receives a rate increase that allows it to earn a fair return on the significant investment that it is making in Utah.

PacifiCorp needs to ensure that it can continue to operate a reliable system and provide excellent service, which requires resources and investment. The Company's financial condition deteriorated dramatically because of the Western energy crisis. During that period, the Company incurred $1 billion in excess net power costs, but will recover less than one third of those costs. Both Standard & Poor's and Moody's cited the high levels of purchased power costs and resulting weaker financial conditions when downgrading PacifiCorp's debt ratings in November 2001. Both agencies continue to have a negative outlook for our ratings.

At the same time, we are very aware of the impact that increased prices can have on our customers. Consistent with the Company's record of long-term price stability, we are seeking only the minimum increase necessary to provide recovery for the unavoidable cost increases the Company is facing in this case. The increase will not be effective until January 2004, and would not be collected through increased rates until April 2004, after the excess power surcharge currently in customer bills expires.

Q. **What has the Company done to improve the economic health of the communities it serves?**

A. The Company is very conscious of its responsibility to the State of Utah, its communities, and customers. The competitive rates that the Company provides are among the lowest in the nation and serve to support economic development by making Utah a low cost option for businesses considering locating in Utah. The 2003 Annual state-by-state rankings by the U.S. Department of Energy, Energy Information Administration (EIA) based on 2001 data show Utah with the third lowest electric costs in the U.S. The Company also works closely with state and local government agencies on economic and community development.

Q. **What efforts has the Company made to control costs?**

A. Through its Transition Plan, the Company has made internal cost control one of its highest objectives. As a result, the Company has achieved a total of $58.5 million in transition benefits for its Utah customers by March 2003. Although these savings do not result in an absolute decrease in price, they do help in a meaningful way to offset what would have been a larger increase. The Company has achieved increased efficiencies through many different initiatives, including improved call center operations, new procurement cost savings, and implementing internal process changes.

In addition to the formal Transition Plan, cost control is one of the essential planks in the Company's strategy. To accomplish cost control, we have designed our planning and budgeting processes to connect more closely with the regulatory process. For example, we review and analyze all budgets with regard to the level of a particular cost already in rates. In this way, we make visible to our line managers the consequences of cost increases in the form of rate increases. This approach creates a discipline deep within the organization to recognize the impact of even small business decisions on the prices our customers pay.

Q. Have these efficiency gains reduced the Company's customer service level?

A. No. Parallel with its cost control initiatives, the Company has made improved customer service a priority. In fact, the Company was recently recognized for its excellent customer service. In a survey conducted by TQS Research, an independent survey group, PacifiCorp ranked among the top ten utilities in the nation, and was the only Western utility included in the top performers. Many of the commitments made at the time of the merger with ScottishPower addressed improved customer service. PacifiCorp has met or exceeded all of these promises, resulting in better customer service across customer classes. For example, in TQS Survey results, 80 percent of large Commercial & Industrial Customers replied that they were very satisfied with the Company. We are also committed to educating customers about energy efficiency and being a trusted resource to them by offering programs to help reduce energy use. With respect to satisfying the eight customer service guarantees we have made to our customers, the Company's success rate Company wide was 99.9 percent for the twelve months ended March 2003.

Q. What else has the Company done to soften the impact of this rate increase on its customers?

A. The Company is attempting to soften the impact on customers in at least two ways. First, PacifiCorp has taken a balanced approach to the revenue requirement requested in this rate case. The Company has voluntarily included in its calculations many of the adjustments contained in the revenue requirement stipulation from the previous rate case. These adjustments include the WAPA Wheeling Contract adjustment ordered in Docket No 99-035-10. In addition, the Company has already stated that it will update its cost of debt during its October filing to reflect an expected reduction in those costs.

The Company has also made concerted efforts to manage the peak growth issue in Utah with the introduction of three new demand side management programs in Utah for the summer of 2003. These three new programs have the objective of reducing the consumption of power at peak times, and slowing the growth in peak demand, therefore reducing stresses on the existing infrastructure and limiting the need to purchase expensive peak power.

The Company also intends to propose rate design changes as part of this case. One objective of these changes will be to soften the impact of rate changes on customers who use less than average amounts of power, or who use the majority of their power at non-peak times.

Q. What other factors are influencing the Company's current and anticipated future costs of providing service?

A. As I previously stated, the Company believes that the ongoing forecasted growth in Utah will continue to drive costs. These costs include the need to acquire or develop additional generation capacity as identified by the Company's Integrated Resource Plan and the current Request for Proposal processes. In addition, as the underlying and peak demand continue to grow faster than in other States, there will be a requirement to continue to enhance the existing power distribution systems. Further, if Utah continues to grow at the rates anticipated, its share of total costs for the PacifiCorp system will increase.

In addition, although difficult to quantify, we are continuing to face increased security and risks in doing business in a post-September 11 environment. We are very aware that we provide an essential service and that we must protect our critical infrastructure. These costs include not just protection of the physical integrity of the system, but more importantly, threats to cyber-security via the internet and otherwise. The Company is also looking at new requirements for capital investments and improvements. In addition to our integrated resource plan, capital expenditure will be required to continue to enhance our systems, to pursue clean air initiatives, and to achieve the relicensing of hydroelectric facilities across our system.

Q. Why do you think the rate increase you are seeking in this case is reasonable?

A. The Company is seeking an increase of $125 million in its Utah revenues. This is an increase in base rates of around 12.5 percent. In light of the investment that it is making to ensure that the electric system can cope with the rapid growth in Utah and the cost increases that PacifiCorp is incurring, these percentage increases are necessary and reasonable.

Q. If this increase were fully implemented, how would PacifiCorp's rates compare to the rates of other utilities?

A. PacifiCorp's prices will remain among the lowest in the United States. Even taking into account the increase requested in this filing, PacifiCorp will continue to be one of the lowest priced electric utilities in the State (including cooperative utilities), with average rates at the low end of all utilities in the state and rates for industrial customers amongst the lowest in the nation. In addition, customer rates, on average will still be lower than they were in 1985.

Financial Strength, Infrastructure, and Reliable Service

Q. How did the energy crisis affect the Company's financial position?

A. The Company's financial position deteriorated significantly during and after the energy crisis, and has yet to recover. The Company absorbed over $700 million in excess power costs incurred during the energy crisis. Those excess net power costs damaged the Company's overall financial condition by reducing profitability and retained earnings, increasing the Company's net debt and financing costs, constraining the level of capital investment, and adversely affecting the Company's capital structure. As an indicator of that decline, ScottishPower's share price has dropped dramatically, from over $34 in early 2000 to $24.49, the closing price for Scottish Power ADSs at the market close on July 25, 2003.

In response to this deterioration in financial condition, the Company temporarily suspended the payment of dividends from PacifiCorp to ScottishPower in the first quarter of 2002. In addition, ScottishPower increased its investment in U.S. assets with an equity infusion of $150 million in 2002, shoring up PacifiCorp's capital structure to prevent a potential rating agency downgrade.

Q. How will the rate increase sought in this case contribute to PacifiCorp's financial health?

A. The Company has focused on providing safe and reliable energy and exceptional customer service at low prices, and at the same time, PacifiCorp, with the assistance of ScottishPower, has taken active steps to maintain its financial ratings in the face of significant financial challenges. The Company now needs additional revenue to maintain critical infrastructure, continue reliable service to customers, and ensure access to needed capital on reasonable terms. Investors tend to invest their money where they can receive at least a reasonable return on that investment; they are unwilling to invest where returns are unreasonably low.

Q. What additional resource needs are projected in the Company's most recent Integrated Resource Plan ("IRP")?

A. The Company's current IRP shows a need for an additional 4000 MW over the next ten years. The Company intends to meet this need through a diverse portfolio of resources, including renewables, demand side management (DSM) initiatives, and thermal baseload and peaking units.

Q. What is the Company's current rate of return and how does that compare to the request in this application?

A. PacifiCorp is currently earning a normalized return on equity of only 5.58 percent in Utah, as described in Mr. Weston's testimony. This is considerably below the 11.00 percent authorized for the Company in its most recent Utah rate case, and falls substantially short of the 11.50 percent return on equity supported by Dr. Hadaway's testimony in this proceeding. Dr. Hadaway's testimony indicates a range of appropriate levels of return on equity from 11.0 to 12.0 percent. Given its risk profile, the Company is requesting that the Commission approve a return on equity of 11.50 percent, which is in the middle of the range and somewhat higher than the percent return requested by the Company in the 2000 Rate Case.

Q. Please explain why the Company is requesting an increase in the return on equity above the level requested in the 2000 Rate Case.

A. In the wake of the energy crisis, all Western utilities face additional risk and uncertainty. The volatility of the Western energy markets during the energy crisis, and the collapse of certain energy companies following the crisis have given many the impression that the electric utility industry remains unstable. The current investigations and reports of wrongdoing during the crisis have further strengthened that impression. FERC investigations into the Western Energy Crisis continue and these ongoing proceedings continue to contribute to a difficult environment. As such, a return on equity in the mid-point of Dr. Hadaway's range is essential to attract capital at reasonable cost from skittish financial markets for needed investments in new resources to meet customers' demand. In addition to these general Western utility industry risks, PacifiCorp faces additional risks associated with operating in Utah, as is apparent from the current Multi-State Process, which is aimed at resolving cost allocation differences between each of the states. These allocation methodologies create not only a situation where there is a recovery gap on the reasonable and prudent expenditure incurred by the Company on a system-wide basis. It also creates increased risks for investors going forward at a time when the Company needs to add additional resources to meet future demand for investment that is created by strong underpinning growth.

Q Are there any other issues specific to Utah?

A Yes. I have already mentioned the need of PacifiCorp to invest in the development of the system going forward. Within this integrated system, Utah is the fastest growing state and will require significant investment going forward. In order to enable the Company to be in a position to make this investment, it is essential that the Company is an attractive proposition to investors. An increase in ROE from 11.0 percent to 11.5 percent would enable this attraction of capital.

Net Power Costs

Q. Please explain how power costs fit into this filing.

A. This filing resets power costs at new, post-energy crisis levels. Mr. Widmer's testimony will demonstrate that Utah's allocated share of baseline power costs has decreased by $67 million from the 2000 Rate Case to this case.

Q. What allocation methodology has the Company used to develop revenue requirement?

A. In accordance with prior Commission orders, the Company has used the Rolled-In methodology, pending the outcome of the Multi-State Process.

Q. Should the Company file for a price increase in one state before cost allocation issues among the states are resolved in the Multi-State Process?

A. Yes. Although the Multi-State Process is progressing toward resolution on how best to allocate costs and address each state's energy policies and preferences in a manner that does not affect other states, the process is not yet complete. Until the participants in that process work out those issues, we continue to operate under the Rolled-In allocation methodology that has been in place now for many years.

Introduction of Witnesses

Q. Please list the Company witnesses and provide a brief description of their subject matter.

A. The Company witnesses filing direct testimony are:

Samuel C. Hadaway, FINANCO, Inc. will testify concerning the Company's return on equity. Based on a combination of Discounted Cash Flow (DCF) and Risk Premium analysis, as well as a review of the current market, the electric utility industry, and company-specific factors, Dr. Hadaway proposes a point value for PacifiCorp's cost of equity of 11.50 percent. He will also present the percentage of PacifiCorp's capital structure related to long-term debt, preferred stock, and common equity.

Bruce N. Williams, Treasurer, will testify concerning the Company's cost of debt and preferred stock. Mr. Williams will show the Company's embedded cost of long-term debt to be 6.510% and the embedded cost of preferred stock to be 5.800%.

J. Ted Weston, Regulation Manager**,** will present the Company's overall revenue requirement based on twelve months ended March 2003 normalized results of operations. The allocation method used is the Rolled–In method. Mr. Weston will present the normalizing adjustments to actual test period costs related to revenue, operation and maintenance expense, net power costs, depreciation and amortization, taxes and rate base.

Reed C. Davis, Director, Planning, will testify as to the changing load factors and load shape within Utah. He will explain how Utah's growth relates to the other states in the PacifiCorp system and how the changing underlying and peak growth in Utah is driving the overall system demand. He will also provide a view of future system growth in Utah relative to the other states.

Mark T. Widmer, Regulation Manager, will testify regarding PacifiCorp's net power costs. Mr. Widmer will describe the calculation of net power costs. Mr. Widmer will also explain how Utah-allocated net power costs in this filing have been reset and are lower than the level now included in base rates.

William Eaquinto, Vice President, Hydro Re-Licensing will testify to the re-licensing processes followed and decisions reached by the Company on five specific hydro re-licensing projects that were completed during the test period.

Daniel J. Rosborough, Director of Employee Benefits, will testify regarding the Company's increased pension and employee benefit costs.

Dawn T. Cartwright, Risk and Insurance Manager will address the increase in the Company's insurance costs and the strategies developed to mitigate these cost increases. Ms. Cartwright's testimony will describe how these cost increases affect PacifiCorp and how PacifiCorp proposes to recover these increased insurance-related costs.

Larry O. Martin, Director, Tax, will testify in support of the Company's request to receive cost recovery for IRS Settlement payments that have been made within the test period and that relate to tax payments that have not been collected through rates.

Mark R. Tallman, Origination Director, Commercial and Trading will provide a comparison between the Gadsby plant and the RFP responses received by the Company and show that the plant was the best resource choice.

J. Rand Thurgood, Managing Director, Resource Development, will discuss the construction and operation of the Gadsby plant, including the facts that it was put into commercial service ahead of schedule and under budget and that it is providing service to Utah customers.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR APPROVAL OF ITS PROPOSED ELECTRIC RATE SCHEDULES & ELECTRIC SERVICE REGULATIONS	Docket No. 03-2035-02 DIRECT TESTIMONY OF J. TED WESTON

JULY 2003

Q. Please state your name and business address.

A. My name is Ted Weston. My business address is, One Utah Center, Suite 2300, 201 South Main Street, Salt Lake City, Utah, 84111-2300.

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 Manager of the Revenue Requirement section of the Regulation Department. I joined the Company in 1983, and I have held various accounting and regulatory positions prior to my current position.

Q. What are your responsibilities?

A. My primary responsibilities include the development, calculation and justification of revenue requirement related issues, which support the Company's regulated earnings and interjurisdictional cost allocations in the Company's retail jurisdictions.

Q. What is your educational background?

A. I received a Bachelor of Science Degree in Accounting from Utah State University in 1983. In addition, I have also attended various educational, professional and electric industry seminars during my career at the Company.

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 results of operations for the twelve months ended March 31, 2003 with limited known and measurable adjustments through January 1, 2004. My testimony presents evidence that based on its normalized results of operations for this test period; PacifiCorp is earning an overall return on equity (ROE) in Utah of 5.58 percent. This return is less than the ROE currently authorized by the Utah Public Service Commission (the Commission) and less than what is required to provide a fair and equitable return for the Company's shareholders. An overall price increase of $128.4 million is required to produce the 11.50 percent ROE supported by Dr. Hadaway's testimony. This overall price increase is subject to adjustment in the Company's October 15, 2003 filing. In support of this conclusion, I introduce and describe the Company's Utah Results of Operations Report for the twelve months ended March 31, 2003 ("base test year" or "base test period") as updated with known and measurable adjustments through January 1, 2004 ("adjusted test year"). In describing this report, I indicate the sources of the base data, and describe certain normalizing adjustments.

Q. Why does your testimony refer to both a "base test year" and an "adjusted test year"?

A. According to the Stipulation approved by the Commission in this docket, the parties agreed that the "base test period" for this general rate case is the 12-month period ended March 31, 2003. The parties also agreed however, that parties may propose "annualizing, normalizing and known and measurable adjustments" to the base test year with known and measurable adjustments limited to those that reflect changes that have occurred or will occur prior to January 1, 2004. Consistent with the terms of the Stipulation, I present the Results of the Operations for the base test period ending March 31, 2003 with known and measurable adjustments through January 1, 2004.

Results of Operations

Q. Please explain the exhibits accompanying your testimony.

A. Exhibit UP&L___(JTW-1) is a page that summarizes the Company's Utah Results of Operations Report. Exhibit UP&L___(JTW-2) consists of the Company's Utah Results of Operations Report for the twelve-month base test period ended March 31, 2003 adjusted for known and measurable changes through January 1, 2004. Total Utah results will be the subject of my testimony. I will hereafter refer to this exhibit as the "Results" or the "Report".

Q. What allocation methodology has the Company used to develop its revenue requirement calculations in this proceeding?

A. The Company used the Rolled-In methodology, pending the outcome of the Multi-State Process (MSP). Until there is a resolution to MSP, we continue to operate under the Rolled-In allocation methodology that was ordered by the Utah Commission in Docket No. 97-035-04.

Q. Please describe the contents of the Utah Results of Operations Report.

A. The Results of Operations Report, which was prepared under my direction, details revenues, expenses and rate base assigned to the Company's Utah jurisdiction using the Rolled-In allocation method. The Report provides twelve-month totals for revenues and expenses and shows rate base as an average of beginning period and end of period rate base. Operating results for the period are presented in terms of both return on rate base and return on equity. The Report begins on page

1.0 with a summary starting in the left-hand column 1 with Utah Unadjusted Results then summarizes normalization and proforma adjustments in column 2 to sum to the Total Normalized Results in Column 3. The unadjusted results (Column 1) are a product of total Company cost multiplied by Rolled-In allocation factors derived from weather-normalized loads. Column 2 combines and summarizes the normalizing adjustments that are necessary to reach the "Total Normalized Results" in Column 3. These normalizing adjustments include normalization for commission ordered adjustments from prior dockets, unusual items that occur during the test period, and annualization of changes that occurred during the test period. Proforma adjustments normalize known and measurable items that will occur on or before January 1, 2004. Column 4 shows the increase in Utah revenues that would be required for the Company to earn an 11.50 percent return on equity from its Utah operations. Column 5 reflects the Utah normalized 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 according to the Rolled-In allocation method are detailed by FERC account in 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 during the base test period. The normalizing adjustments, which are required to smooth the impact of any unusual events, which occurred during the base test period, are identified on page 1.1, supporting documentation for columns two and four is contained in Tabs 3 through 9. 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 1.0?

A. I observe that, as detailed in Column 4 of page 1.0, an overall price increase of $128.4 million is required to produce the 11.50 percent ROE supported by Dr. Hadaway's testimony. However, because of the Stipulation, which caps the total recovery the Company can seek in this proceeding, the Company is only seeking recovery of $125.0 million. The Company will update its overall price increase request in its October 15, 2003 filing.

Q. Please explain the primary elements of the Company's proposed price change.

A. Compared to the costs included in current Utah prices there are significant changes to several key elements of the revenue requirement. The largest component of the proposed price increase is driven by Utah load growth and infrastructure additions to support that growth. In Docket No. 01-035-01, Utah net plant was $2.5 billion; today it is over $2.9 billion an increase of over $436 million. This plant increase is driven by two components—new plant, which represents approximately $370 million, and the allocation impact of Utah load growth. This new plant includes Utah's share of the $70 million for the Gadsby Peakers, $66 million in hydro re-licensing projects, and over $94 million of new infrastructure to serve load along the Wasatch Front. With respect to Utah load growth, the System Generation factor, which is weighted 75 percent demand and 25 percent energy, has grown from 37 percent in the last rate case to 39.2 percent. This growth in relationship to the other states allocates an additional $66 million of rate base to Utah. The $436 million of additional rate base and associated depreciation expense account for $67 million of the requested price change. The second largest component is pensions and employee benefits, which account for $14 million of the increase. Changes to the insurance industry have resulted in an increase in insurance premiums and uninsured losses, which accounts for $11 million of the price increase.

Development of Base Data (Unadjusted Results)

Q. Please explain the process for compiling the base data used in the Utah Results of Operations Report.

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.

Q. Do the Company's unadjusted Results of Operations for the twelve months ended March 2003 provide a reasonable basis for setting Company prices?

A. No. The base test year data reflects the operating environment and the unique set of circumstances that occurred during that twelve-month period. It is a fair depiction of actual results for the period, but is not appropriate as a predictor of on going Company performance, which should be the basis of Company prices. 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.

Normalizing Adjustments

Q. Please describe what you mean by normalizing adjustments.

A. 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. In reporting results of operations, it is the Company's goal to develop a "typical" test period, free from effects of unusual events. To accomplish this goal, normalization adjusts for out-of-period events and the impact of unusual, non-recurring events, such as one-time write-offs. Adjustment 3.7, Reverse Contingencies, is an example of the normalization of a nonrecurring event. Annualization is also required to reflect the effect of changes that occur partway through the test period. For example, a wage increase that takes place in March should be adjusted to reflect a full 12-month impact.

Adjustments need not be restricted to events that occurred within the test period. In order to 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. A case in point would be the adjustment to reflect the effects of the recently approved depreciation rates that occurred after the end of the base test period.

Q. Would you explain the normalizing adjustments for the test period?

A. Yes. Page 1.1 is a summary by tab of the adjustments. Supporting detail for each normalizing adjustment is provided in the Report under Tabs 3-9. A brief description and the underlying reason for each adjustment is contained in my testimony. Additional information is provided in the descriptions for each of the adjustments included within the exhibit. For discussion purposes, all 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. Please explain the revenue adjustments summarized under Tab 3, page 3.0.

A. **Weather Normalization** (Adjustment 3.1) – The weather normalization adjustment removes from test period revenue the effects of 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. This adjustment increases Utah residential revenues by $1,776,738 and reduces commercial revenues by $3,017,035. Test period state load data used in the calculation of jurisdictional allocation factors have also been temperature normalized.

Effective Price Change (Adjustment 3.2) – The effective price change adjustment increases revenues by $444,711. This adjustment annualizes any contract changes, including special contracts expiring, with customers returning to tariff schedules.

Revenue Normalizing (Adjustment 3.3) – This adjustment normalizes test period revenues by removing out-of-period adjustments. It also removes the credit from the Centralia gain that customers received on their bills recorded in general business revenues. The adjustment decreases Utah situs revenues by $2,525,237.

Special Revenue Reclassification (Adjustment 3.4) – Historically, the revenues from many of the special contracts were allocated system-wide. All of these below-tariff or non-tariff contracts have, or will soon, expire. Most have returned to standard tariff or have been renewed at tariff-equivalent prices and there is no need to treat them as system revenue credits. Adjustment 3.4 reverses all system-allocated special contract revenues from the test period and direct-assigns those revenues to the appropriate states. This reclassification increases Utah allocated revenues by $12,587,054. The revenue difference between the special contract rate and the standard tariff rate for the affected Utah customers was accounted for in Adjustment 3.2.

USBR/UKRB Discount (Adjustment 3.5) – Under contract with PacifiCorp, the U.S. Bureau of Reclamation (USBR) and the Klamath Basin Water Users' Protective Association (UKRB) receive a discounted tariff in exchange for their water rights. The contracts preserve the Company's interests in three hydro projects on the Klamath River. Because all customers share in the benefits of the hydro production from these plants, the PacifiCorp Interjurisdictional Taskforce on Allocations (PITA) agreed it was appropriate that the costs should 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. This increases Utah's allocated share of hydro expense by $4,091,897. This treatment is consistent with the treatment approved in the Docket No. 01-035-01.

SO2 Emission Allowances (Adjustment 3.6) – Over the years, PacifiCorp's annual revenues from the sale of emission allowances have been very uneven. Thus, the level of emission allowance sales in any particular year is likely not to reflect the normalized, ongoing level of revenue from such sales. In addition, recognizing SO2 revenues in the year of the sale provides all the benefits to current customers at the expense of customers in the future. Therefore, the Company's approach is to amortize these allowance sales over a four-year period. This is the same treatment used by the Company and accepted by the Commission in Docket No. 01-035-01. The unamortized gain is included as a reduction to rate base. Adjustment 3.6 reduces operating expense by $1,501,327, Utah's allocated share of the SO2 emission allowance amortization, and reduces rate base by $1,459,538 to reflect the unamortized gain.

Reverse Contingencies (Adjustment 3.7) – During the late nineties, an accrual was set up on the books for a potential liability arising from pool contract disputes. In 2002 the disputes were settled without PacifiCorp incurring any liability. The wholesale sales accrual that was set up in prior periods was reversed during September 2002, overstating test period revenues. In 2001, the Company also established contingencies for several other customers that were reversed during the test period. This adjustment removes the non-recurring revenue associated with these prior period reversals, reducing Utah revenues by $8,035,679.

Q. Please explain the O&M adjustments summarized under Tab 4, page 4.0.

A. **Customer Service Deposits** (Adjustment 4.1) – 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 the interest is treated as an expense of electric operations. Absent this adjustment, the interest true up, Adjustment 7.1, would nullify any recovery of customer service deposit interest. This treatment was approved in Docket No. 97-035-01 and each subsequent case. This adjustment increases Utah operating expenses by $233,815 and reduces rate base by $5,371,405.

Remove LTIP Expense (Adjustment 4.2) – This adjustment removes the costs of PacifiCorp's executive stock option plan, (LTIP or Long Term Incentive Plan) in accordance with the Commission's order in Docket No. 97-035-01. This adjustment reduces Utah operating expense by $111,776.

Severance Accrual (Adjustment 4.3) – During the base test period, the transition plan regulatory asset was reduced to reflect more current expectations associated with employee severance costs. This entry reduced the asset balance by crediting the asset and debiting expense. Adjustment 4.3 removes the asset write-down from base test period results reducing Utah operating expense by $2,076,526.

FAS 106 (Adjustment 4.4) – In Docket Nos. 20000-ET-92-50 and 20001-ET-92-22, the Wyoming Commission authorized an accrual method of accounting for FAS 106 expenses (post-retirement benefit costs). The order authorizing deferral treatment for the difference between accrual and pay-as-you-go was established for no more than three years with amortization of the remaining balance to occur over the next seven years. The amortization of the deferred balance was completed in December 2002.

Because this amortization should be direct assigned to Wyoming and the amortization will not continue into the future, Adjustment 4.4 removes the amortization expense from the revenue requirement calculation, which reduces Utah's operating expenses by $311,163 and reduces amortization expense by $28,211.

Sale Of Naches Hydro Plant (Adjustment 4.5) – The USBR has negotiated with the Company to purchase the Naches Hydro Plant and to obtain the associated water rights. While the terms and agreements have been finalized, the sale will not be completed until after the end of the base test period, therefore the transaction was not reflected in unadjusted results. This adjustment normalizes test year revenue requirement by removing annual booked depreciation expense of $344,105, O&M expenses of $59,108, and property tax expense of $25,657, which represents Utah's allocated share of the costs associated with the Naches Plant. The plant investment is removed in Adjustment 8.9 in Tab 8.

Pension and Benefit Adjustment (Adjustment 4.6) – With the downturn in the capital market, actuarial reports from the adjusted test period indicate the Company's pension fund requires increased contributions that substantially increase pension expense levels on a going-forward basis. In addition to pension and post-retirement benefits, the Company has experienced increases to employee medical, dental and other benefits. Adjustment 4.6 normalizes the base test year pension and benefits to an adjusted test period level. This adjustment increases Utah operating expenses by $11,003,052.

Blue Sky Program (Adjustment 4.7) – 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 all revenues and expenses associated with this program from the test period. Adjustment 4.7 reduces Utah revenues by $261,533 and reduces Utah expense by $362,642.

Miscellaneous General Expense (Adjustment 4.8) – This adjustment removes from results of operations certain miscellaneous expenses that should have been charged to non-regulated expenses, reducing Utah operating expense by $380,532.

Property Insurance (Adjustment 4.9) – During the base test period, property and liability insurance and uninsured losses were over $43 million. Ms. Dawn Cartwright explains some of the changes to the insurance industry and the impact of those changes on the Company's insurance costs in her testimony. Insurance expense for the adjusted test year is expected to be $40.6 million, this is $2.8 million lower than actual expense due to a reversal during the base test period of a prior period accounting entry. Adjustment 4.9 decreases Utah's operating expense by $1,108,611.

FERC Price Cap Accrual (Adjustment 4.10) – FERC has retroactively adjusted the price cap on energy transactions in California from $250 per MWH to $40 per MWH. Based on this action, the Company accrued for a possible net liability of $17 million associated with those energy trades. Because the outcome of this issue is not known, this adjustment removes the expense from test period results. Adjustment 4.10 decreases Utah operating expense by $7,589,680.

Noell Kempf Climate Action Project (Adjustment 4.11) – In Docket No. 99-035-10, the Utah Commission authorized a five-year amortization of the Company's $1.75 million participation in this program. This adjustment increases Utah operating expense by $53,599 and rate base by $87,475.

General Wage Increase (Adjustments 4.12 & 4.13) – PacifiCorp has several labor groups, each with different effective contract renewal dates. Adjustments 4.12 and 4.13 annualize the effective wage increases received during the base test period for labor charged to operation and maintenance accounts and restates expense as though the wage increase was effective for the entire test year. The annualization was calculated by identifying actual wages for each labor group by month, and applying the negotiated wage increase to the wages for the months prior to the effective contract date. These adjustments also remove wages paid to employees who left during the year. Adjustments 4.12 and 4.13 decrease Utah's allocated share of operating and maintenance expense by $2,843,852.

Pro-Forma General Wage Increase (Adjustments 4.14 & 4.15) – These adjustments normalize labor expenses to better match labor cost during the period the proposed prices will be in effect. It uses the annualized labor from Adjustments 4.12 and 4.13 as the base and adds the scheduled wage increases for the period April 1, 2003 through January 1, 2004 into the test period as of the date they become effective. This adjustment increases Utah's allocated share of operating and maintenance expense by $1,538,978.

FICA Adjustment (Adjustment 4.16) – Effective in 2002, the earnings base for Social Security increased from $84,900 to $87,000. This change will increase the

Company's expense for Social Security tax. Adjustment 4.16 annualizes this increased expense and also reflects the FICA tax associated with the annualized and pro forma General Wage increases (Adjustments 4.12, 4.13, 4.15 & 4.16). Adjustment 4.16 increases taxes other than income by $1,254,525 on a Utah basis.

Q. **Does your testimony provide a detailed explanation of how the Net Power Cost adjustment was calculated?**

A. No. The Net Power Cost adjustment normalizes revenues and expenses in a manner consistent with normalized operation of production facilities, as described in Mr. Widmer's testimony. The normalized Net Power Cost developed and explained in Mr. Widmer's testimony is reflected in Tab 5. However, I will explain how the Net Power Cost is reflected in results and also describe several other adjustments that affect power costs.

Q. **Please explain the Net Power Cost adjustments summarized under Tab 5, page 5.0.**

A. **Net Power Cost Study** (Adjustment 5.1) – The Net Power Cost adjustment normalizes steam and hydro power generation, fuel, purchased power, wheeling, and sales for resale in a manner consistent with the contractual terms of sales and purchase agreements. It also normalizes hydro and weather conditions for the adjusted test period, twelve-months ending January 1, 2004, as described in Mr. Widmer's testimony. This study imputes additional revenues to the SMUD sales as ordered in Docket No. 01-035-01. Page 5.1.1 of the Report compares the normalized Net Power Costs developed by Mr. Widmer to the actual test period amounts to determine the amount of the adjustment. The net impact of

Adjustment 5.1 is to decrease Utah revenues by $25,417,733, with an offsetting decrease in operating expense of $79,093,311.

US Magnesium Replacement Power (Adjustment 5.2) – Pursuant to the terms of the Utah Commission Order in Docket No. 01-035-38, service to US Magnesium was subject to economic interruption during the months of July and August in 2002, and the months of June, July, August, and September in 2003 and 2004. This contract includes an option for US Magnesuim to buy through the interruption at market prices. In 2002, US Magnesium exercised its option to buy through, and concurrently, PacifiCorp purchased power in the market to meet US Magnesium's load. The Utah Commission Order also provides that both the cost of serving and the revenues associated with serving US Magnesium, including the cost and revenue associated with the buy-through power, would be direct assigned to Utah.

During the base test period US Magnesium was subject to economic curtailment during July and August. On a going-forward basis, US Magnesium will also be subject to economic curtailment during June and September of 2003 (in addition to July and August). Their contribution to system peak and energy consumption during what will be the June through September curtailment periods was removed from the calculation of the jurisdictional allocation factors. During the economic curtailment periods, the cost of any buy through purchased power, and the corresponding revenue, are direct assigned to US Magnesium and the Utah Jurisdiction. This adjustment changes the allocation of the $1,348,920 replacement purchase power expense from system allocation to direct assignment (situs) to Utah. This adjustment increases Utah operating expense by $820,568.

FAS 133 (Adjustment 5.3) – Adjustment 5.3 removes FAS 133 costs from the test period. Effective June 2001, FAS 133 required that all companies recognize derivatives as either assets or liabilities and measure those instruments at fair market value. For financial reporting purposes, the changes in fair market value are booked to either income or expense. Adjustment 5.3 removes the impact of these financial reporting requirements and reduces Utah operation expenses by $6,050,105.

Trail Mountain Closure Amortization (Adjustment 5.4) – In March 2001, PacifiCorp closed its Trail Mountain Mine, which supplied coal to the Hunter Plant, a jointly-owned facility. In Docket No. 01-035-02 the Commission approved the deferral of the un-recovered investment associated with the mine and the amortization of these costs over five years, beginning April 1, 2001.

Consistent with the Commission's order, in April 2002, two regulatory assets were recorded on the Company books, one for the Trail Mountain Closure costs and the other for the Unrecovered Trail Mountain Investment. These regulatory assets are being amortized over a five-year period beginning April 2001 and ending March 2006. The amortization expense is recorded in Account 501, Fuel Expense, however this amortization was removed from the normalized fuel costs included in Adjustment 5.1, Net Power Cost study. Because the normalized Net Power Cost does not include the amortization of Trail Mountain closure costs, Adjustment 5.4 includes PacifiCorp's share of twelve months amortization expense of $7,935,023. This adjustment also removes the $385,200 of joint owner payments to PacifiCorp from Account 456, because the joint owners share of amortization expense is not included.

In addition, because the regulatory assets were not recorded until April 2002 and include the joint owner's portion, it was necessary to correct the balance of the unamortized regulatory asset included in the base test year. Adjustment 5.4 increased Accounts 182M and 186M by $5,935,724 and $7,911,367 respectively, reflecting the appropriate regulatory asset balance of $27,772,578 in the adjusted test period.

Adjustment 5.4 decreases Utah revenues by $151,167, increases operating expense by $3,108,031, and increases rate base by $5,423,700.

West Valley Lease (Adjustment 5.5) – On March 5, 2002, PacifiCorp entered into a fifteen-year operating lease agreement with PPM Energy, Inc. ("PPM"). The agreement provides PacifiCorp with complete operational control and the entire output of a 200 MW natural gas-fired power plant in West Valley City, Utah. The output of this resource is modeled and reflected in Adjustment 5.1; however, only nine months of lease expense is reflected in the base test period. In addition to the lease expense the Company reimburses PPM for the property taxes associated with this facility. This adjustment annualizes the lease and property tax expense. Adjustment 5.5 increases Utah allocated expense by $1,556,119.

DSM/Load Curtailment Reversal (Adjustment 5.6) – During the power crisis the Company initiated load curtailment and conservation programs to mitigate rising power costs. This adjustment removes the final entries from results increasing Utah expense by $674,407.

WAPA Wheeling Contract (Adjustment 5.7) – In Docket No. 99-035-10, the Commission ordered PacifiCorp to impute wheeling revenues for the difference between the WAPA contract and the Company's FERC wheeling tariff rates. This adjustment is made in compliance with that order, increasing Utah revenues by $2,130,169.

P&M Strike Amortization (Adjustment 5.8) – In Docket No. 01-035-01, the Commission approved deferral and amortization of the increased costs incurred by the Company due the P&M strike over the six-year term of the new P&M labor agreement. This adjustment increases fuel expense by $299,449 and rate base by $948,256.

Q. Please explain the depreciation and amortization adjustments summarized under Tab 6, page 6.0.

A. **Annualized Depreciation Expense** (Adjustment 6.1) – This adjustment re-states the test period depreciation expense to a level consistent with average plant balances using the depreciation rates from the 1997 study. Adjustment 6.1 increases Utah allocated expense by $848,391.

Annualized Accumulated Depreciation (Adjustment 6.2) – Adjustment 6.1 annualizes depreciation expense based on March 2002 and 2003 average plant balances. This adjustment reflects the impact of that annualization on the accumulated depreciation balance. Adjustment 6.2 decreases Utah allocated rate base by $263,209.

Pro Forma Depreciation (Adjustment 6.3) – This adjustment reflects depreciation expense at the rates included in the Company's new depreciation study that was submitted to the Commission for approval in Docket No. 02-035-12. Adjustment 6.1 applies the depreciation rates from the 1997 study to the average plant balances; this adjustment captures the incremental change in depreciation expense associated with moving to the depreciation rates in the Company's new depreciation study. Adjustment 6.3 decreases Utah allocated expense by $6,772,343.

Pro Forma Accumulated Depreciation (Adjustment 6.4) – Adjustment 6.3 normalizes depreciation expense using the most recently authorized depreciation rates applied to March 2002 and 2003 average plant balances. This adjustment reflects the impact of that normalization on the accumulated depreciation balance. Adjustment 6.4 increases Utah-allocated rate base by $2,101,085.

Q. Please explain the tax adjustments summarized under Tab 7, page 7.0.

A. **Interest True-Up** (Adjustment 7.1) – The amount of interest expense included in the test period is a cost of financing rate base through debt securities. Therefore, it is appropriate to synchronize, or true up, the amount of interest expense with the amount of rate base. This true up was accomplished by multiplying the jurisdiction-specific adjusted rate base by the weighted cost of debt. The interest determined in this manner was then compared to the actual interest recorded during the base test period to determine the necessary adjustment. Interest expense is a deduction to taxable income therefore, the revenue requirement impact of the interest true up is reflected as a change in income tax expense.

Adjustment 7.1 decreases the interest expense allocated to Utah by $7,090,843, thereby increasing income tax expense by $2,691,046.

Wyoming Wind Tax Credit (Adjustment 7.2) – This adjustment normalizes the federal income tax credit associated with placing the Wyoming wind generating plant into service before December 31, 2001. The credit is based on the generation of the plant. Adjustment 7.2 reduces Utah income tax expense by $857,347.

Property Tax Adjustment (Adjustment 7.3) – This adjusts test period property tax expense to a level consistent with plant balances, increased revenues, and property valuations. Adjustment 7.3 increases the property taxes allocated to Utah by $637,964.

Deferred Income Tax Balance Reclassification (Adjustment 7.4) – A review of the accumulated deferred income tax balance identified various balances that had inappropriately been combined and allocated on the System Overhead factor. Many of these items were tax differences associated with creating regulatory assets from the previous Utah cases that should have been situs assigned. There were also balances related to the deferred net power costs that should not be included in the revenue requirement calculation. This adjustment breaks out the balance detail and assigns the correct allocation factor to each component increasing Utah rate base by $33,462,048.

IRS Settlement (Adjustment 7.5) – During the base test period the IRS completed an audit of PacifiCorp's tax filings from 1989 through 1998. Mr. Larry Martin's testimony explains why the additional tax expense from the audit should be recovered from customers. The Company is proposing that the costs be amortized over a period not to exceed five years. Utah's portion of the additional tax expense was determined by calculating a weighted average of the Income Before Tax factor over that same time frame and applying that weighted IBT factor to the total cost. Utah's share of this expense is $32.5 million, which amortized over five years, increases Utah current taxes by $6,491,684 and rate base by $29,212,577.

Q. **Please explain the miscellaneous rate base adjustments summarized under Tab 8, page 8.0.**

A. **Update Cash Working Capital** (Adjustment 8.1) – This adjustment is necessary to true up the cash working capital for the normalizing adjustments made in this filing. Cash working capital is calculated by taking total operation and maintenance expense allocated to Utah (excluding depreciation and amortization) and adding Utah's share of allocated taxes, including state and federal income taxes and taxes other than income. This total is divided by the number of days in the year to determine the Company's adjusted daily cost of service. The daily cost of service is multiplied by net lag days to produce the adjusted cash working capital balance. Adjustment 8.1 reduces Utah's rate base by $1,580,371.

Plant Held for Future Use (Adjustment 8.2) – At the end of fiscal year 2003, the Company determined that specific properties in Plant Held for Future Use should be written off. Adjustment 8.2 removes this investment from results reducing Utah rate base by $502,353.

APS Combustion Turbine Payment (Adjustment 8.3) – In Docket No. 97-035-01, the Commission approved a proposal by the DPU that the costs of the APS payment should be shared between customers and shareholders. That sharing is achieved by leaving the annual amortization in results and removing the unamortized balance from rate base. Adjustment 8.3 reduces rate base by $4,190,898.

Bridger and Trapper Mine (Adjustment 8.4) – PacifiCorp owns 21.47 percent interest in the Trapper Mine, which provides coal to the Craig Generating Plant. This adjustment is necessary to add the Company's share of Trapper Mine plant investment to rate base, since this investment is in the Company's books in Account 123.1 - Investment in Subsidiary Company. Account 123 is not normally a rate base account. Utah's allocated share increases rate base by $1,671,174.

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. Therefore, this adjustment is necessary to properly reflect the Bridger Coal Company investment in test period rate base. Utah's allocated share increases rate base by $21,101,653.

Organizational Cost (Adjustment 8.5) – This adjustment is to conform to the treatment adopted in Docket No. 97-035-01, which shares merger costs between shareholders and customers by subtracting merger costs from rate base and leaving the amortization expense in results. This adjustment also adjusts tax expense by the shareholders' 50 percent share of merger costs. Adjustment 8.5 decreases Utah's rate base by $1,673,040.

Environmental Settlement (Adjustment 8.6) - 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 adjustment is necessary to reflect the insurance proceeds in the test period as a reduction to rate base. The credit will be reduced or amortized over time as PERCO expends dollars on clean-up costs. The expended balance reduces Utah rate base by $8,779,658. An entry to correct the allocation of customer advances during the base test period increases Utah rate base by $2,854,130.

Major Plant Additions (Adjustment 8.7) – This adjustment normalizes the rate base effects of recognizing base year major plant items greater than $1 million into rate base as if the additions took place at the beginning of the test period. The depreciation expense, reserve balances, and tax impacts are accounted for in adjustments 6.1 and 6.2. Adjustment 8.7 increases rate base by $50,302,648. Rate base will be updated as part of the October 15, 2003 filing for known and measurable changes.

Proforma Major Plant Additions (Adjustment 8.8) - This adjustment normalizes major plant additions that are expected to be completed between April 2003 and January 1, 2004. More than half of these additions are investment in infrastructure along the Wasatch front to support Utah load growth. The second largest component is hydro re-licensing costs described in Mr. Eaquinto's testimony. Page 8.8.1 details each of the components with estimated completion dates. This adjustment increases Utah rate base by $130,035,064 and depreciation expense by $4,589,265.

Sale of Naches Hydro (Adjustment 8.9) - In March 2003, PacifiCorp received a partial payment for the sale of the Naches hydroelectric facility. The USBR made this payment up front for the purpose of obtaining the water rights while the sale is still being completed. It is expected that the sale will be completed late in 2003. The accounting transactions reflecting the sale are not reflected in base test year. This adjustment removes the assets from rate base and adds back the accumulated deprecation. The annual depreciation and O&M expenses are removed in Adjustment 4.5 in Tab 4. This adjustment decreases Utah rate base by $1,692,599.

System Benefit Charge (Adjustment 8.10) - This adjustment removes from results of operations the deferred regulatory assets relating to the Utah DSM programs that are part of the proposed system benefits charge. This will reduce Utah rate base by $6,740,784.

Q. Are there any previous Commission-ordered adjustments that have not been reflected in these results.

A. Yes. I have excluded two adjustments from the adjusted test period results that were previously ordered. They are the dis-allowance of one third of the Customer

Service System and an allocation of a portion of the Company's postage expense below-the-line.

Q. Would you describe each of these adjustments and why it is no longer appropriate to include them in results?

A. Yes. I would like to briefly explain the Customer Service System adjustment. At the time of the Utah Power, Pacific Power merger both companies had their own customer billing systems. Pacific Power's system was called Customer Information Accounting System (CIAS). Utah Power's system was called Customer Accounting System (CAS). Both divisions continued to use their separate systems for an additional eight years after the merger. By the mid-nineties, the supporting software for these systems was outdated, making it necessary to replace them. If the Company was going to replace these legacy systems, it made good sense to have and maintain only one customer billing and information system rather than two. So in 1996, the Company implemented the new Customer Service System (CSS). In the 97-035-01, case the DPU raised three main concerns about this new billing system. First, the system was designed to handle over six million customers when the Company only had slightly over one million customers. Second, the system was designed to handle sales and marketing activities. Third, customer service costs has increased due to this new system.

While CSS has the capacity to handle six million customers, this incremental capacity did not come at additional cost to the Company. Memory is available at almost no additional cost. The best comparison is a Microsoft Excel spreadsheet. While each Excel is designed with the maximum number of sheets of 255 and each sheet has 65,536 rows and 256 columns, few if any applications fully utilize all this capacity. But Microsoft does not offer discounts based on the number of tabs used since the incremental cost of this additional capacity doesn't cost any more. Similarly, CSS additional capacity was available at almost no additional cost.

The second concern was that the system was designed to handle sales and marketing activities. CSS was designed to generate electric customer's bills. It has never been used for sales and marketing activities. PacifiCorp electric operations have not incurred any CSS incremental costs for sales or marketing activities.

The final issue raised was that the cost to customers has increased. While this is true, that replacing two completely amortized systems with a new system increased costs. It is important to note that doing nothing with the old systems was not an option, they had to be replaced. That additional cost to replace two old outdated legacy systems with a new customer information system for the total Company was the prudent decision.

To summarize the additional customer capacity came with little if any incremental cost. The Company is not using CSS for sales and marketing activities. Finally the legacy systems had to be replaced which did increase costs to customers. CSS is the Company's customer accounting and information system and should be paid for by customers.

Q. Why do you believe it is no longer necessary to allocate a portion of postage costs below the line?

A. In Docket No. 97-035-01, the DPU was concerned that PacifiCorp was subsidizing some of its non-regulated affiliates by including bill stuffers in its monthly bills. While the Commission agreed that this practice added no costs to customers it determined that it was an unfair competitive advantage to the affiliates. An adjustment was prepared based on the ratio of the inserts for the non-regulated affiliates to the total bill inserts. This percentage was then applied to total postage costs with the product excluded from the Company's revenue requirement calculation. Since the ScottishPower merger most of these affiliates no longer exist and with the reorganization PacifiCorp is no longer the parent Company, but sister to any remaining companies. PacifiCorp does not include bill stuffers for any non-regulated activities; therefore it is no longer necessary or appropriate to make this adjustment.

Q. Does this conclude your testimony?

A. Yes.

Exhibit
UPL__(JTW-1)

PacifiCorp
Exhibit UP&L _____(JTW-1)
Docket No. 03-2035-02
Witness: J. Ted Weston

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of J. Ted Weston
Utah Results of Operations Summary

July 2003

PACIFICORP
State of Utah - Electric Utility
Actual, Adjusted & Normalized Results of Operations
Twelve Months Ended March 2003

	(1) Unadjusted Results	(2) Normalizing Adjustments	(3) Total Normalized Results	(4) Price Change	(5) Results with Price Change
1 Operating Revenues:					
2 General Business Revenues	925,574,542	6,766,143	932,340,685	128,373,894	1,060,714,579
3 Interdepartmental	(41)	53	12		
4 Special Sales	410,123,046	(25,679,267)	384,443,779		
5 Other Operating Revenues	44,353,718	(3,556,642)	40,797,076		
6 Total Operating Revenues	1,380,051,265	(22,469,713)	1,357,581,552		
7					
8 Operating Expenses:					
9 Steam Production	252,943,792	24,325,297	277,269,089		
10 Nuclear Production	-	-	-		
11 Hydro Production	9,811,980	3,991,900	13,803,880		
12 Other Power Supply	497,928,316	(102,499,665)	395,428,650		
13 Transmission	38,703,606	(1,232,140)	37,471,466		
14 Distribution	35,705,038	(316,225)	35,388,812		
15 Customer Accounting	39,901,780	(7,754,554)	32,147,226	666,814	32,814,040
16 Customer Service & Info	5,215,909	(11,485)	5,204,424		
17 Sales	287,303	-	287,303		
18 Administrative & General	126,953,562	6,655,665	133,609,227		
19 Total O&M Expenses	1,007,451,286	(76,841,207)	930,610,079		
20 Depreciation	139,787,137	(1,678,792)	138,108,345		
21 Amortization	21,894,085	(28,211)	21,865,874		
22 Taxes Other Than Income	40,873,941	1,866,832	42,740,774	381,270	43,122,044
23 Income Taxes - Federal	13,664,720	26,692,765	40,357,485	42,540,826	82,898,311
24 Income Taxes - State	3,045,017	2,861,491	5,906,507	5,780,592	11,687,099
25 Income Taxes - Def Net	7,634,183	(894,980)	6,739,203		
26 Investment Tax Credit Adj.	(4,876,135)	-	(4,876,135)		
27 Misc Revenue & Expense	(1,291,444)	(1,267,512)	(2,558,956)		
28 Total Operating Expenses:	1,228,182,791	(49,289,615)	1,178,893,176	49,369,503	1,228,262,678
29					
30 Operating Rev For Return:	151,868,474	26,819,902	178,688,376	79,004,391	257,692,768
31					
32 Rate Base:					
33 Electric Plant In Service	4,920,007,012	192,509,413	5,112,516,425		
34 Plant Held for Future Use	1,219,417	(566,234)	653,184		
35 Misc Deferred Debits	109,518,747	(13,251,908)	96,266,838		
36 Elec Plant Acq Adj	39,476,121	-	39,476,121		
37 Nuclear Fuel	-	-	-		
38 Prepayments	4,126,651	-	4,126,651		
39 Fuel Stock	23,469,730	(9,219)	23,460,512		
40 Material & Supplies	36,975,184	-	36,975,184		
41 Working Capital	34,646,356	(1,580,371)	33,065,985		
42 Weatherization Loans	23,099,729	-	23,099,729		
43 Misc Rate Base	6,738,222	-	6,738,222		
44 Total Electric Plant:	5,199,277,170	177,101,681	5,376,378,851	-	5,376,378,851
45					
46 Rate Base Deductions:					
47 Accum Prov For Deprec	(1,876,249,202)	2,837,911	(1,873,411,291)		
48 Accum Prov For Amort	(93,903,216)	8,355,031	(85,548,185)		
49 Accum Def Income Tax	(461,794,317)	63,859,761	(397,934,556)		
50 Unamortized ITC	(239,686)	-	(239,686)		
51 Customer Adv For Const	(8,947,210)	2,854,130	(6,093,080)		
52 Customer Service Deposits	-	(5,371,405)	(5,371,405)		
53 Misc Rate Base Deductions	(49,552,229)	(1,432,610)	(50,984,839)		
54					
55 Total Rate Base Deductions	(2,490,685,860)	71,102,818	(2,419,583,042)	-	(2,419,583,042)
56					
57 Total Rate Base:	2,708,591,310	248,204,499	2,956,795,809	-	2,956,795,809
58					
59 Return on Rate Base	5.607%		6.043%		8.715%
60 Return on Equity	4.614%	0.967%	5.581%		11.500%
61					
62 TAX CALCULATION:					
63 Operating Revenue	171,336,260	55,479,178	226,815,437	127,325,809	354,141,246
64 Other Deductions					
65 Interest (AFUDC)	-	-	-		
66 Interest	99,889,022	(7,090,843)	92,798,179		92,798,179
67 Schedule "M"	(29,360,162)	458,406	(28,901,757)		(28,901,757)
68 Income Before Tax	42,087,075	63,028,427	105,115,502	127,325,809	232,441,310
69					
70 State Income Taxes	3,045,017	2,861,491	5,906,507	5,780,592	11,687,099
71 Taxable Income	39,042,058	60,166,936	99,208,994	121,545,217	220,754,211
72					
73 Federal Income Taxes + Other	13,664,720	26,692,765	40,357,485	42,540,826	82,898,311

Exhibit
UP&L__(JTW-2)

PacifiCorp
Exhibit UP&L _____(JTW-2)
Docket No. 03-2035-02
Witness: J. Ted Weston

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of J. Ted Weston
Utah Results of Operations Report

July 2003

THIS EXHIBIT IS VOLUMINOUS AND IS PROVIDED UNDER SEPARATE COVER

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

	)	
IN THE MATTER OF THE	)	Docket No. 03-2035-02
APPLICATION OF PACIFICORP	)	
FOR APPROVAL OF ITS	)	DIRECT TESTIMONY
PROPOSED ELECTRIC RATE	)	OF REED C. DAVIS
SCHEDULES & ELECTRIC	)	
SERVICE REGULATIONS	)	
	)	

JULY 2003

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

A. My name is Reed C. Davis, my business address is 825 N.E. Multnomah, Suite 600, Portland, Oregon 97232, and my present position is Director, Planning in the Commercial and Trading Organization.

Qualifications

Q. Briefly describe your education and business experience.

A. I received an undergraduate degree in Business Administration from Brigham Young University. I have worked for PacifiCorp since 1979 and have held various positions all dealing with energy, load, customer and revenue forecasting for the budgeting and planning areas of the Company. I was promoted to my present position in 2003.

Q. Please describe your current duties.

A. I am responsible for the development of the forecasts of kWh sales, number of customers, system loads, and system peaks for the Company's six retail jurisdictions and various operational control areas. I am also responsible for the accounting of revenues, sales, and customers by rate and jurisdiction for the Company.

Q. Have you testified previously?

A. Yes. I have submitted testimony to the Idaho, California, and Oregon Commissions.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I explain that Utah has over the past 10 years been the fastest growing of the States that PacifiCorp serves, both in terms of increases in customer numbers and average energy use per customer. I explain why the Company expects this rate of growth to continue into the future and some of the causes for this. I then explain the impact that this consistent grow rate has on the costs that are allocated to Utah, especially when compared to what is happening on a demand basis to the other States that PacifiCorp serves. Finally I consider the changing shape of the load demand in Utah and consider some of the current and future implications of this.

Q. Why are you putting forth this testimony?

A. In preparing the various forecasts the Company uses, we research to discover the various causes of the growth the Company has seen in the past and then study to see if there will be a continuation of that growth into the future. Because we expect continuation of several of the causes we have identified, we believe that this testimony will support the Commission in some of their decision making and also support recommendations put forth in this rate case by other witnesses. The Company also believes that by examining the key causes of growth, it is possible to better understand the key cost drivers in this current rate case proceeding.

Historical Growth by State

Q. How would you summarize the historical growth the Company has seen?

A. Ehhibit UP&L___(RCD-1) shows the average annual growth for each of the six jurisdictions the Company currently serves. This exhibit shows that for the calendar years from 1993 to 2002 the east portion of the service territory, except Wyoming, has shown more growth than the west portion of the service territory. It also shows that, of the six states, Utah has experienced the largest growth. We expect Utah to continue to have greater growth on average than the other states we serve.

Q. Is this higher growth rate new to Utah?

A. No. From 1983 to 1992, (the prior 10 years) Utah experienced a 3.4 percent average annual growth rate for energy.

Q. What else can you tell from this exhibit?

A. There are two causes that have impacted Utah that are not impacting the other states in the same way. First, Utah has had faster customer growth than all states. We expect Utah to continue to have faster customer growth than the other states in the future. Secondly, on average each customer appears to be using more energy each year. We expect Utah to continue to have faster energy growth than customer growth for the next several years.

Q. What makes you say that each year the average customer is using more energy than they did the year before?

A. If the average growth rate for the energy is equal to the average growth rate for the customer additions, on average new customer additions are the cause of the growth. When the energy growth rate is lower than the average customer growth rate, the average customer must be using less each year. When the energy growth rate is greater than the customer growth rate, the average customer must be using more each year to push up the energy growth rate. This latter set of facts is currently true in the Company's Utah service territory, so it appears that the average customer is using more energy than they did before.

Q. What has happened in the last few years in the states you serve?

A. The states have had rather different economic climates over the past few years that have created some differences in the growth rates we have seen. Economic climate in the west, and particularly in Oregon, has been suffering more than surrounding states. Oregon has been facing a weaker economy as demonstrated in the higher unemployment rate for the state.

Q. How has this impacted the growth rates?

A. On the bottom of Exhibit UP&L___(RCD-1), I have shown the customer and energy growth rates each state has experienced from calendar year 2000 to calendar year 2002. Oregon and Washington have seen over a 40% drop in customer growth rates from historical averages, where Utah and Idaho have around a 20% drop in customer growth rates. Utah still remains the fastest growing state in terms of customer numbers during this period. Additionally, the energy growth in Oregon and Washington have decreased dramatically from the average over several years, while in other states they have remained the same or increased.

Q. Exhibit UP&L___(RCD-1) shows that the Utah energy growth rate in the last couple of years has declined while the customer growth rate has not shown a similar size change. This seems different than the other eastern states. Why is that the case?

A. Geneva Steel, a major steel producer in the state, greatly reduced its purchases from the Company in 2001 and 2002. After adjusting for this change, Utah would show an energy growth of about .9 percent over this time period, showing that Utah has seen some slowing in demand for additional energy per customer in the recent past, but not as much as Oregon and Washington.

Q. What is the impact of different long-term growth rates in each state and the diverging growth rates between states during the recent years?

A. The allocation factors developed to distribute costs to the jurisdictions in which the Company has service territories are impacted. The states with the generally long-term faster growth rates should see an increase in their allocation factors over time as more and more of the growth is assigned to them. However, in the last few years that impact has been compounded due to the different economic climates in each state. The more rapid declines in some states will create additional growth in the allocation factors in the states that are declining more slowly or growing. However, on a cost per kWh basis, allocations should remain somewhat stable between states.

Q. What is the impact to Utah in this rate case?

A. I believe that this impact is two-fold. Utah has been the fastest growing state in terms of customers and energy used per customer in the last 10 years. This had lead to an increase in system allocation factors. Secondly, in the last few years, while there has been a slowing of growth in customer numbers and a reversal in energy demand growth in some states, Utah has continued to show underlying growth which has had the effect of compounding the impact of the change in allocation factors.

Q. Earlier you mentioned that average usage per customer is growing or declining in the different states. What is the cause for this?

A. The Company cannot really describe the causes of growth adequately in terms of an average use per customer at the state level. The "average customer" is in fact a mix of many different types of electricity consumers. For example, some use electricity for lighting, some for manufacturing, some for space conditioning. If the Company groups customers with similar characteristics together, it is much easier to identify trends and understand how each grouping is changing over time.

Utah Growth by Class of Service

Q. How do you plan to group customers?

A. The Company typically groups customers by the type of service they receive. The Company groups customers into Residential, Commercial, Industrial, Public Street and Highway Lighting, Other Sales to Public Authorities, and Irrigation categories.

Q. How does each category of customers contribute to the total energy consumed in the state?

A. Exhibit UP&L___(RCD-2) shows two pie charts. One pie chart shows what percent of the total energy sales in Utah each category contributes. The other chart shows what percent of the total customers in the state each category has. These charts show that the residential, commercial, and industrial categories consume the bulk of the energy in Utah. They also show that by far, residential customers are the majority of the customers the Company has.

If you were to do the quick calculation of dividing the energy consumed by the number of customers in each category, you would see that, on average, the residential customers use the least energy per customer and the industrial customers use the most. You would also see that, on average, the industrial customers use much more energy per customer than either the residential or commercial customers.

Q. Given the wide difference in use per average customer for each category, how does each category impact the state overall growth?

A. Exhibit UP&L___(RCD-3) was prepared to help show how the growth has occurred from 1993 to 2002. This exhibit shows that the residential and commercial customers have grown the fastest over this time period. It also shows that on average they are using more each year than the year before

Q. Does the decrease in the industrial customers shown in this exhibit demonstrate that the state is losing its industrial base?

A. No. This exhibit shows the effects of a change in billing systems not a loss in industrial base. The Company instituted a new billing system, called CSS, in approximately 1997. At that time, they reclassified some billing types from one category to another. Prior to 1997, temporary electricity service accounts, those used by builders for electricity during the construction phase of buildings or homes, were all assigned to the industrial category. After the change to CSS, each was assigned to a category based on the final use of the building under construction. So, for example, temporary service accounts for homebuilders are now put into the residential category where previously they were included in the industrial category. This change had a sizable impact on the count of industrial customer but little noticeable impact on the count of residential customers.

Q. Is the growth occurring equally across the state?

A. It depends on the customer class. Exhibit UP&L___(RCD-4) shows the growth seen in geographic locations across the state by customer category. A review of the growth by geographic locations indicates that the bulk of the residential growth has happened along the Wasatch Front, from Ogden in the north to Orem/Provo in the south, east into Park City, and west into Tooele. Additionally, the Cedar City and St.George areas of the state are having the greater residential growth. The commercial and industrial growth has been a little more uniform across the state.

Q. Earlier you implied that current economic conditions help drive the growth rate. What has the growth rate been in recent years in Utah based on that state's economic climate?

A. I have prepared Exhibit UP&L___(RCD-5) to help explain this. This exhibit shows the long-term average growth rate from 1993-2002 next to the recent years (2000-2002) average growth rates and the percent change in the two growth rates. It shows this for both energy and customers. For the residential class, this exhibit shows that the energy growth rate drops by approximately 25 percent, from 4.5 percent over the long-term to 3.4 percent in the near term. The customer growth rate drops by approximately 28 percent, from 2.99 percent over the long term to 2.16 percent in the near-term. This very similar change in the energy and customer growth rates indicate that most of the decline in energy growth is from a slow down in customer growth, but that the average growth in use per residential customer continues growing.

However, for the commercial and industrial classes, this exhibit shows a very different effect. In both of these classes, the average energy growth rate from long-term to near term has declined a far greater amount than the customer growth rate over the same period. This is an indication that these customers are using less energy on average in the current period than in past periods. The impact in the industrial class is further enlarged by the large decline in sales to Geneva Steel.

Q. What impacts has the Company faced with the differing growth rates by customer category?

A. The cost associated with serving the different customer categories is not the same. There is a much higher distribution cost associated with supplying residential and commercial customers than with supplying industrial customers. As such, with more rapid residential and commercial customer growth in the long-term, the Company would face greater distribution costs associated with this type of growth. The slight short-term decreases in growth somewhat mask this continuing trend. While residential and commercial growth has slowed, each class is still growing, adding pressure to the distribution costs. Also, the decrease in the Geneva load further hides impacts from the growth when you only look at the total energy change. For example, if the Company loses 50 MW of industrial load, the Company could add approximately 50,000 homes and see no load growth. However, the Company would have experienced sizable increases in distribution costs during the same time period as it adds distribution systems to serve the 50,000 new homes.

Q. Earlier, you stated that you expect the growth in Utah to continue at a higher rate than other states. Can you now explain how that will happen by customer category?

A. Yes.

Residential Growth

Q. Why do you expect Utah to see a continuing high residential customer growth compared to surrounding states?

A. One reason is that Utah has a higher than average birth rate than surrounding states. Also, as people age they have a tendency, all other things remaining equal, to locate where they grew up. As such, Utah has a fundamental difference from surrounding states that will result in a higher customer growth.

Q. What other factors may drive residential load growth in Utah?

A. Utah also tends to have a more educated labor pool and lower average living costs. This larger population of educated workers and lower wages tends to be a draw for businesses. Additionally, Utah offers a different culture from many locations. Many people seek to move to the state to enjoy the cultural differences in Utah. Utah also appears to enjoy a strategic location in the West. Utah is somewhat centrally located in the west between population centers in Colorado, California and the Pacific Northwest. This makes it a prime location to establish businesses and have equal access to major western population centers.

Q. On average Utah residential customers tend to use more energy each year. Do you expect that to continue?

A. Yes.

Q. Please explain.

A. Some of the changes in Utah that have led to higher residential usage in Utah are expected to continue. During the last decade Utah homes on average have increased in size. As the growth continues, the Company expects the average size of homes to increase. Additionally, the Company is seeing more homes that have Central Air Conditioners (CAC). Customers across our Utah service territory are seeking more comfortable living conditions and seem to be willing to pay for them. CAC are becoming seen as the norm for the way to space condition on hot summer days. More new homes require CAC as a selling point. Customers with Evaporative Air Conditioners (EAC) are changing their equipment to keep up with the norm.

Q. Does the CAC increase have any other impact on the Company?

A. Apparently yes. Exhibit UP&L___(RCD-6) shows the residential customers' average use aggregated for the winter months and summer months from 1993 to 2002. This shows that the use during the four summer months is growing much faster than the remaining eight months of the year. This appears to be having a big impact on the growth of the system peak. Prior to 1999, the system as a whole peaked during the winter months. Because of the growth in Utah, the Company has started to experience summer peaks and expects this pattern to continue in the future. . This is evident in Utah state grow rates. From 1993 through 2002, while the energy growth in Utah averaged 3.6 percent per year, the summer peak average growth rate was 5.7 percent.

Commercial Growth

Q. Do you expect the commercial customer growth to continue?

A. Yes, however, it appears to be more widely distributed across the state. Exhibit UP&L___(RCD-7) shows that growth is higher in many more areas than seen for the residential customer category. This appears to us to be due to a few different reasons. The state in general will experience higher growth to supply the services needed for the greater residential growth. That service-related growth does not have to be concentrated in the same areas that are experiencing rapid residential growth. In addition, Utah has seen growth in what I refer to as "exporting service businesses." For example, a number of phone centers have been built in Utah in the past years. These are phone centers that either handle incoming calls or tele-market with outgoing calls across the nation. They have provided many service jobs that do not supply the needs of local customers. They are capitalizing on the labor pool benefits mentioned earlier. This is a benefit that Utah enjoys that other states may not have.

Q. Did the 2002 Winter Olympics impact the growth rate of the commercial category?

A. The Company had expected the Winter Olympics to impact the commercial growth rate, however, we cannot see as many changes as we expected. Exhibit UP&L___(RCD-4) shows that the commercial growth was fairly widely distributed across the state. We would not expect that to be the case if the

Olympics were a major factor in the growth. If the growth was solely due to the Olympics, we would expect it to be more centralized. Exhibit UP&L___(RCD-8) shows the commercial growth year by year. There are major growth periods all across the ten-year horizon. We see some slightly higher years in 1999 and 2000, but the increase is not that much greater than the prior years. While the Olympics may have had some effect, it appears that it was not as great as some expected and that the bulk of the increase over the past years has not been directly related to the Olympics.

The Company has seen another very positive benefit to the state from the Olympics. Utah has been a tourist center, and taken advantage of the many conventions and business meetings held annually. The positive coverage of the Olympics has further identified Utah as a desirable location for a convention or business meeting and tourism should continue to benefit the businesses in Utah that support it.

Q. What is happening to the commercial average customer use?

A. Exhibit UP&L___(RCD-7) shows commercial customers' average use aggregated for the winter months and summer months from 1993 to 2002. This exhibit shows that customer use for the four summer months is growing faster than the remaining eight months of the year. This also appears to be having a big impact on the growth of the system peak and contributing to the summer peak growth. However, this exhibit also shows that the commercial category is seeing growth across the winter sector; summer growth is just faster.

Industrial Class Growth

Q. What can you tell us about the growth in the industrial category?

A. Prior to the last decade, Utah's industries appeared to be heavily concentrated in industries that depended on the natural resource supplies in the state, such as coal, uranium, oil, gas and copper. While these industries are still very important contributors to the state overall, they have started to play a less important role. During the last decade, the Company has seen a trend to a more diversified economy. Various manufacturing companies have moved into the state for the reasons mentioned earlier in my testimony. Additionally, the exporting service businesses in the commercial sector have contributed greatly to providing a diversified economic base for the state. The state now seems to have an economic base that will be more stable during economic cycles. As business in the state becomes more diverse, the state may have more stability in a variety of economic conditions, i.e. when some sectors of the business community are experiencing contracting cycles others may offset with expanding cycles.

Q. What about the industries heavily dependent on the state's natural resources?

A. One of the things we have been concerned with about this type of economy is that at some point the business will run out of resources, or the cost of extracting the value from the resources will become more costly than alternative methods or locations. At this point these industries will leave the state. As the state diversifies the economic base, this becomes less of a concern.

Q. How do you see the past causes of growth continuing in the industrial category?

A. Many of the things that have helped the State in the past we see continuing. Utah will continue to have a highly educated workforce. Many people will continue to desire to locate in the state, and the state will likely continue to have a higher birth rate than the nation so there will be a sizable and affordable labor pool. Utah's location as the crossroads of the West will keep it ideally located near major western population centers and business markets. With the changes coming in information technologies and the world markets being opened more easily through the Internet, Utah may have additional advantages that we have not seen that will help diversify and grow the economy more.

Q. You expect each class to be growing quite differently. Are there additional impacts this is having on the system that may change the system in the future?

A. I believe that there are additional impacts on the system that must be watched. Exhibit UP&L___(RCD-9) shows how the Utah summer average weekday load shape has changed over time. To create this exhibit, I averaged the weekday loads from June and July of 1993 and 2003 by hour. I then indexed each year's hourly values to the minimum for that year, to remove growth. This gives the hourly shape for each year on a comparable basis with each hour being a ratio to the minimum. This graph shows that the shape is changing and higher in the daytime hours. This exhibit corroborates the analysis earlier in my testimony that showed the increasing summer usage from the residential and commercial customers.

Q. What does the changing load shape mean?

A. It indicates that the Company may need to change the way we supply loads to our customers. It may be an indication that the best way to provide energy is by changing the Company mix of base load units and peaking units. It is certainly something for the Company to review further and watch. It will certainly have some impact on the generation cost required to serve Utah customers. Additionally, there will likely be continued additions to the distribution system to increase the capacity. Because customers are using more, the existing system may not have the capacity to handle the increased demand. Also, it may appear to some that the increases to the system are excessive because the increased system demand is for a shorter period during the day. However, there is a need to make sure that the system can handle the maximum demand placed on it. This has been compared to needing a six-lane freeway during the rush hours and a four-lane freeway during the remaining portion of the day.

Q. Does this conclude your testimony?

A. Yes