BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In The Matter Of The Application Of	)	
PacifiCorp For Approval of Its Proposed	)	Docket No. 04-035-42
Electric Rate Schedules and Electric	)	Revenue Requirement Filing
Service Regulation	)	

TESTIMONY OF RONALD J. BINZ

ON BEHALF OF AARP

Filed: December 3, 2004

DIRECT TESTIMONY OF RONALD J. BINZ

Q. What is your name and address?

A. My name is Ronald J. Binz. My business address is 333 Eudora Street, Denver, Colorado 80220-5721.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of AARP, a nonprofit, nonpartisan membership organization for people aged fifty and over. AARP provides information and resources; advocates on legislative, consumer, and legal issues; assists members to serve their communities; and offers a wide range of products and services to its members. Nationally, AARP has over thirty-five million members, including 187,000 members in Utah.

Q. What is your occupation?

A. I am President of Public Policy Consulting, a firm specializing in energy and telecommunications regulatory matters. I provide consulting services to a variety of public-sector and private-sector clients in the energy and telecommunications industries, primarily in the regulatory arena. My consulting practice dates to 1979, except for the years 1984-1995 when I served as Colorado Consumer Counsel.

Q. Please summarize your experience in utility regulation.

A. I also served as President of the Competition Policy Institute (CPI) in Washington, D.C. CPI is a non-profit organization that I founded in March 1996 and describe as a combination consumer group and "think tank." CPI's activities included advocacy before regulators and lawmakers, education, research and working with other consumer organizations. We recently suspended our federal advocacy work, focusing our efforts on the educational role of the organization.

For eleven years prior to Public Policy Consulting and CPI, I was Consumer Counsel for the State of Colorado. In that role, I represented the interests of residential, small business and agricultural consumers of telecommunications and energy before the Colorado Public Utilities Commission, the Federal Communications Commission (FCC), the Federal Energy Regulatory Commission (FERC), the courts and legislative bodies.

During my tenure as Consumer Counsel I served as the President of the National Association of State Utility Consumer Advocates (NASUCA) for two years and chaired the organization's Telecommunications Committee for three years. In those roles (and at CPI) I have testified numerous times before Congressional committees on energy and telecommunications matters.

Prior to my work with the Office of Consumer Counsel, I was a consulting utility rate analyst. I have testified before regulatory commissions, courts and arbitration panels in ten states on behalf of a variety of clients. These have included consumer organizations, senior citizen groups, agricultural utility consumers, homebuilders, state agencies, telecommunications resellers and local governments.

I am a frequent speaker and presenter at industry, regulatory and legislative conferences and symposia. I am a member of the Harvard Electricity Policy Group and recently served on two advisory commissions to the Federal Communications Commission. My curriculum vita is attached as Appendix A to this testimony.

Q. What is your educational background?

A. I received a B.A. in Philosophy from St. Louis University in 1971. I received M.A. in Mathematics from the University of Colorado in 1978. I entered the Masters Program in Economics in 1980 and completed 27 hours of graduate work. I was researching my Masters Thesis on Regulated Industries in 1983 when I was appointed to the Public Utilities Commission by Colorado Governor Richard Lamm.

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

A. PacifiCorp is proposing to increase its Utah base electric rates by $111 million, an overall increase of almost 10% over current revenues in Utah. The average residential customer (using 773 kwh/mo) would see an increase of about $11.38 per month under the Company's proposal. I was asked by AARP to review the rate filing and to make recommendations to the Commission.

Q. How is your testimony organized?

A. First, I present an introduction to the testimony and a summary of my findings and recommendations. Second, I identify and discuss some of the appropriate regulatory principles that the Commission should use in evaluating the Company's request. Third, I describe several modifications to PacifiCorp's filed case that are consistent with the regulatory principles identified.

I. Introduction and Summary of Testimony

Q. Mr. Binz, why is this case important to AARP members in Utah?

A. PacifiCorp is proposing a significant increase in its electric rates in Utah. If implemented by the Commission, the Company's proposal will add $137 to the annual electric bill of the average residential customer in Utah. AARP members are certainly willing to pay rates that cover their costs; but like all consumers, they are not willing to pay more than needed to compensate PacifiCorp for its costs and to maintain reliable electric service over the long term.

Q. Please summarize your conclusions and recommendations to the Commission.

A After reviewing the Company's testimony and exhibits, together with substantial amounts of information produced in discovery, I have the developed the following recommendations for the Commission:

- It is likely that PacifiCorp's cost of equity capital has fallen since the Company's last rate case. The Commission should reduce the authorized return on equity capital from the current level of 10.7%.
- The Commission should adjust the Company's estimates of rate base:
  - The Company proposes to increase rate base by including an estimate of cash working capital. This is appropriate as long as all leads and lags are considered. In its filing, the Company does not correctly reflect the expense lag associated with the payments of coupon interest on long term debt and dividends on preferred stock.
- The Commission should adjust the Company's estimate of net power costs:
  - Hydro Hedge – The Company has included the cost of a financial hedge in its estimate of net power costs. Since power costs used in

rate making are estimated using a model that normalizes loads, supplies, and costs, then ***by definition*** consumers cannot benefit from the hedge. While it may be prudent for PacifiCorp to purchase hedges, it is not appropriate to include the costs without also reflecting the benefits in rates.

    - WAPA Contract – In its filing PacifiCorp has reversed a long-standing Commission adjustment to impute value to the WAPA contract. This policy change should be rejected by the Commission.

- The Commission should adjust the Company's estimates of test year expenses:

    - Incentive compensation – The Company has proposed to include the full amount of incentive compensation. The Commission should not include in rates that portion of incentive compensation that is related to corporate performance.

    - Projected salary expense – The Company has overstated labor costs FY 2006 by failing to consider the effect of increased labor productivity.

    - The Commission should adjust the Company's claimed income tax expense to reflect the fact that PacifiCorp Holdings, Inc. files a consolidated tax return.

Q. Does AARP have a recommendation for the total revenue requirement for PacifiCorp?

A. Not at this time. Due to resource limitations, AARP has not addressed all issues in the case. Importantly, AARP is not offering testimony on the cost of equity capital or on the use of the GRID model to estimate net power costs. Further, AARP has not examined all accounting issues raised in the case. For these reasons, the organization reserves the right to endorse the recommendations of other parties and will endeavor to develop a "bottom line" number to recommend to the Commission as the case proceeds.

II. APPROPRIATE REGULATORY PRINCIPLES

Q. Please describe the regulatory principles that the Commission should use in deciding this case.

A. As the Commission is well aware, it has an obligation to set rates that balance the interests of consumers and regulated companies. Rates should be sufficient to give a utility an opportunity (but not a guarantee) to cover its expenses and earn a return on investment sufficient to attract capital. If rates are set too high, income is transferred inappropriately from consumers to the utility's shareholders; if rates are set too low, the Company's ability to raise capital could be impaired, leading eventually to degraded service.

In setting rates, the Commission follows the familiar formula:

$$\text{Revenue Requirement} = (\text{Rate Base})*(\text{Cost of Capital}) + \text{Operating Expenses} + \text{Depreciation and Amortization} + \text{Taxes}$$

Q. How are these elements of rate making measured?

A. Because ratemaking attempts to evaluate the relationship among revenues, investment, cost of capital, and expenses, it is important that these quantities be measured or estimated on a common basis. In usual practice, these quantities are measured or estimated during a *test year*. This is a period of time, usually one year, which i) may have occurred in the recent past; ii) may be underway at the time of hearing; or iii) may be set in some future period. Whether the test period is historic, current, or future, the essential task is the same: determine which prices generate revenue sufficient to cover expenses and produce the appropriate return for the utility.

Q. How can a utility earn its authorized rate of return if the test year is an historic test period?

A. While absolute quantities might change over time, the relationship among revenue, investment, and expenses remains *relatively* fixed as new rates become effective. And since rates (prices) are determined by the revenue requirement divided by units of consumption, every new kilowatt-hour sold or new customer added carries with it some contribution to return on investment and coverage of expenses.

Moreover, cost of service regulation can provide important incentives to efficiency if properly implemented. Earnings levels should not be guaranteed so that the utility has the need to continuously become more efficient and reap the rewards of increased productivity between rate cases.

Q. What is the test period in this case?

A. PacifiCorp has chosen to use the future test period of the twelve months ending March 31, 2006. In its filing, PacifiCorp has made estimates of revenues, investment and expenses to this test year to ensure that it was representative. While future test years have a sound theoretic basis, they are often difficult to implement in practice due to the fact that regulators must attempt to predict the values of investment, revenues and expenses for some future period.

Q. What is meant by the "matching principle" when setting rates using rate base, rate of return regulation.

A. The "matching principle" is nothing more than a requirement that regulators be consistent in the adjustments made to test year results. For example, if electric plant in service is measured at the end of the test period, the associated accumulated depreciation should also be measured at the end of the test period. If the level of plant investment is projected for a future test period, the matching principle requires that the test period also project the number of customers and level of sales revenues available to support that investment.

The matching principle is no empty regulatory requirement. A test period is similar to a financial reporting period for a firm. Violating the matching principle would be similar to a firm reporting profitability by using costs from one period but revenue from another period. Wall Street determines the value of a company in part on a firm's earnings per share in a given period. In ratemaking, the Commission is trying to accomplish a parallel task: to ascertain the earnings per unit sold in a given period. In order for cost of service regulation to function correctly, the Commission must undertake this task on a consistent basis.

In the case of a future test year, the challenge to the Commission is to ensure that the estimates of future investment and expense are properly matched to the estimate of future revenues. As I will show later, PacifiCorp's filing fails to make this match in a very significant expense item.

III. APPROPRIATE ADJUSTMENTS TO PACIFICORP'S FILED CASE

Q. What rate of return is AARP recommending?

A. The currently effective return on equity (ROE) for PacifiCorp in Utah is 10.70%, approved by the Commission as part of a stipulation among the parties in the Company's last case. In its application, the Company is proposing rates that would increase ROE to 11.125%. This means that PacifiCorp is seeking an 8.732% return on rate base, as shown in the following table that relates the Company's requested ROE and its weighted cost of capital:

PacifiCorp's Requested ROE and Weighted Cost of Capital

Component	*Ratio*	*Cost*	*Wt Cost*
Long Term Debt	51.0%	6.54%	3.335%
Preferred Stock	1.2%	6.64%	0.079%
Common Equity	47.8%	11.13%	5.319%
Weighted Cost of Capital			**8.732%**

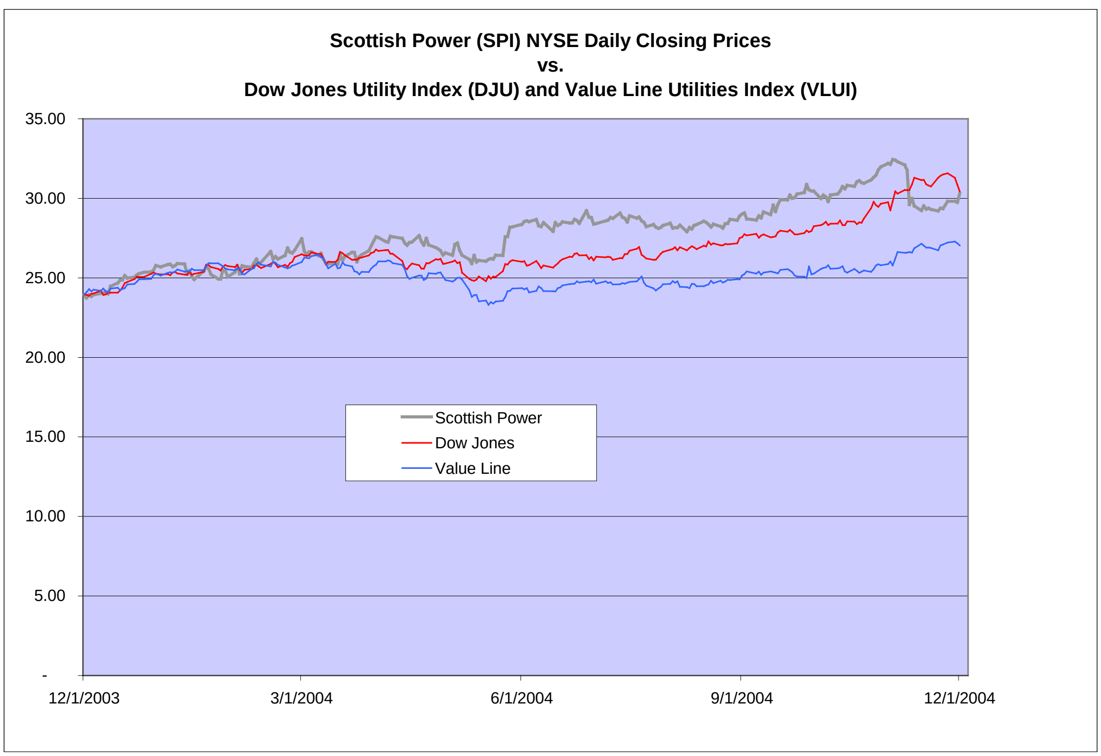
Q What considerations should the Commission make in determining the appropriate cost of equity capital for PacifiCorp?

A The commission is well aware of its obligation to allow PacifiCorp to implement rates that give the Company an opportunity to earn a rate of return sufficient to attract capital. It also has an obligation to ratepayers to ensure that the rate of return it awards is no higher than what is needed. As shown in Exhibit RJB-1, each percent change (100 basis points) in ROE changes the revenue requirement by about $24.2 million. In other words, the difference between a return on equity of 10.125% and a return of 11.125%

raises rates by about $24.2 million. This translates into a change in annual electric costs of $30 for the average residential customer.

Q What is the state of the overall health of Scottish Power's common stock?

A Since the Company's last Utah rate case, in which the Commission approved a stipulation among the parties in January 2004, the market value of Scottish Power's common stock has risen almost continuously. In fact, the relative increase in the share price has outstripped increases in two major utility indices, the Dow Jones Utilities average and the Value Line Utilities index. The following chart shows the performance of Scottish Power shares and these utility industry equity price indices during the past twelve months. The chart is also reproduced in Exhibit RJB-1, page 2 for easier reading.



Q What conclusions can be drawn from the data used in this chart?

A I think the performance of the Company's stock over the past year shows that the cost of equity for PacifiCorp has likely fallen over the past year. The fact that investors have bid up the price of the stock by 18% between February 2004 and November 2004 shows that they require a relatively smaller return, as a percentage of the price paid for the stock. This effect is similar to the inverse relationship between the price and yields of bonds: bond prices rise as interest rates fall. This is true generally for utilities, but especially so for PacifiCorp since its price increase has outstripped the indices.

I have not undertaken the type of technical analysis that the rate-of-return witnesses in this case have completed. On the other hand, I think the change in price of the industry and the company provides important circumstantial evidence that the cost of equity has fallen since it was measured 9 months ago. AARP believes that the Commission should lower the return on equity for PacifiCorp below the currently authorized level of 10.7%.

Q Is AARP recommending a specific return on equity capital in this testimony?

AARP is not offering empirical evidence that attempts to estimate the Company's cost of equity capital using the various financial models used for that purpose. In this case, the Company has provided expert testimony from Dr. Samuel Hadaway. In addition to Dr. Hadaway's testimony, the Commission will be presented with cost-of-capital testimony on behalf of the Division of Public Utilities (DPU) and the Committee of Consumer Services (CCS). AARP reserves the right to endorse the findings of another party on this issue after AARP has had the opportunity to fully review their analyses.

Q. What adjustments are you recommending to PacifiCorp's estimate of rate base?

A. I am recommending that the Commission revise the Company's estimate of Cash Working Capital to reflect the lag experienced in payment of interest on long-term debt and dividends on preferred stock.

Q. Please explain your proposed adjustment to cash working capital.

A. "Cash Working Capital" is a rate base item that attempts to measure the amount of cash that a utility's investors are required to advance to fund operations. It is logical that a stock of cash must be on hand to pay operating expenses. And since this cash is not invested, regulators compensate investors for their opportunity costs by adding cash working capital to rate base and permitting a return at the utility's weighted cost of capital. Cash working capital can be positive or negative, depending on the degree to which revenues from customers lead or lag payment of costs.

A utility's actual cash account will fluctuate as customers pay their monthly bills and the utility pays for expenses such as fuel, materials, vendor payments, insurance premiums, repayment of short term debt, interest on long term debt, and dividends on preferred stock. The last three items are not classified as operating expenses as such, but their payment requires the utility to accrue and disburse cash in regular cycles.

In its filing, PacifiCorp calculates that, on average, revenues from customers lag payment of operating expenses. To estimate cash working capital, PacifiCorp multiplies the net lag days by the average daily operating expense and concludes that the total Company has an average cash working capital requirement of $53.5 million. Utah's share of this balance is $24.8 million, which is proposed to be added to Utah rate base.

But this analysis ignores another important aspect of the Company's cash management. In order to make timely interest payments and preferred stock dividends, the Company accrues cash from customer payments in advance of the due date of these expenses. Said another way, the Company realizes a net cash "lead" on these non-operating expenses. This cash can be used for any purpose, including short term investments, reduction of short-term debt, or, for that matter, payment of operating expenses.

Q. Have you prepared an exhibit that shows the appropriate offset to Cash Working Capital that should be made in this case?

A. Yes. Exhibit RJB-2, shows the calculation of the appropriate offset to Cash Working Capital. Interest payments on long term debt are made semi-annually so that the cash required to make the payments is acquired from customers during the six months prior to the interest payment. The average level of lead cash obtained in this fashion is achieved halfway through the six-month period.

Similarly, there is an expense lag associated with payment of dividends on preferred stock. Dividend payments on preferred stock made quarterly so that the cash required to make the payments is acquired from customers during the three months prior to the interest payment. The average level of lead cash obtained in this fashion is achieved halfway through the three-month period.

The combination of these two effects is a cash lead (expense lag) of $13.22 million. I recommend the Commission reduce the level of Cash Working Capital included in rate base by this amount. This adjustment to rate base reduces the revenue requirement by approximately $1.88 million.

Q. What response do you expect from PacifiCorp?

A. I expect PacifiCorp to argue that, since preferred stock dividends and interest on debt are not operating costs, the associated cash leads should not be considered when calculating Cash Working Capital.

But this criticism misses the point. I am not arguing that interest payments involve working capital in the sense of operating requirements. Instead, I am arguing that the full amount of Cash Working Capital should not be included in rate base without an offset that recognizes that shareholders are not putting up the full amount of Cash Working Capital. Instead, utility customers are providing the utility with significant amounts of cash that can fund the operating cash working capital required. Unless this recommended offset is made, ratepayers will be giving the utility a return on an artificial cash requirement. Stated another way, utility customers will not get credit for <u>their</u> opportunity costs on the cash provided to the utility in advance of the payment of interest and dividends.

Q. Please turn to your proposed adjustments to operating expenses. What adjustments should be made to net power costs?

A. The Commission will receive significant testimony from the CCS and DPU witnesses concerning net power costs. This testimony will likely address the inner workings of the GRID model, the input assumptions used in the model, and the appropriateness of including various purchase contracts. AARP reserves the right to endorse or disagree with elements of those analyses. In this testimony, I am limiting my testimony on net power costs to two issues. The first is whether to include the costs of a "hedge" contract in net power costs. Although the amount of money at stake is not large, it raises a significant policy issue. The second issue is whether to impute revenues to the WAPA contract, an issue which this Commission has faced in the past.

Q. How are net power costs estimated in PacifiCorp's filing?

A. For PacifiCorp, "net power costs" are defined as the Company's cost of fuel plus purchased power costs minus wholesale sales. PacifiCorp estimates net power costs using a dispatch model, called GRID, which simulates the operation of the PacifiCorp system over a one-year period. GRID accepts inputs that characterize the Company's resources: plant capacities, fuel prices, heat rates of power plants, maintenance schedules, purchase power contract terms, transmission availability and capacity, reserve requirements, etc. The model also accepts inputs about loads: seasonal, daily and hourly loads, as well as special contract sales, etc.

These inputs are combined in a computer model that "dispatches" the system according to certain rules that reflect the constraints of the generation and transmission system. The output of GRID is an estimate of the net costs of running the system during the simulation. This estimate is then allocated to the state jurisdictions. Finally, this allocated estimate of net power costs, together with any regulatory adjustments in a given state, are included in the Results of Operations for a test year and used to set electric rates.

In order to model the PacifiCorp system, the GRID model relies on assumptions about variables, including, among many others, hydro availability. As might be expected, the model makes the neutral assumption about this variable: that hydro conditions will be normal – river flows will correspond to a 50-year average.

In the real world, of course, any of the variables used by GRID in its modeling can depart from their assumed values. For example, hydro conditions in the PacifiCorp territory in recent years have been extremely low. Nonetheless, rates are set under the assumption of normal supply and demand conditions.

Q. Please explain PacifiCorp's inclusion of this hedge contract in net power costs.

A. PacifiCorp has entered into a hedge contract intended to moderate swings in actual net power costs. The Aquila hydro hedge, costs PacifiCorp $1.75 million per year. Depending upon the availability of hydro resources, PacifiCorp either pays a counterparty or receives a payment from a counterparty. Since a hedge is the combination of a put and a call, its will smooth out swings in PacifiCorp's costs of hydro capacity. In effect, the Company will not profit as much during periods of excess hydro availability, but it will not lose as much during periods of low hydro availability. In other words, its risks are "hedged" in both directions. PacifiCorp has included the cost of this hedge contract in its estimate of net power costs for the test year.

Q. Should the cost of this hedge be included in rates?

A. No. Because rates are set by PacifiCorp based on the normalized results of the GRID model, users pay prices for energy that are not affected by swings in hydro availability or swings in temperature. In other words, consumers cannot, *by definition*, realize benefits from the hedge contracts. On the other hand, the hedge contracts do dampen swings in power costs paid by for by PacifiCorp after rates have been set.

Viewed correctly, these hedge contracts are actually seen to be financial arrangements that can insure against swings in earnings by PacifiCorp shareholders. While this may be beneficial to shareholders who bear the risk (and reap the rewards) of differences between modeled net power costs and actual power costs, there is no corresponding benefit to ratepayers.

I have prepared Exhibit RJB-3, page 1 to show removal of the costs associated with the Aquila hedge. The effect of this adjustment is to reduce the Utah test year revenue requirement by $733,000.

Q. Are you concerned about the incentive provided to PacifiCorp if the Commission excludes the cost of hedges from rates?

A. PacifiCorp does not have an electric cost adjustment mechanism in Utah, so that fluctuations in actual net power costs do not affect Utah rates. Reducing these fluctuations in the short run by employing hedges does not translate into benefits to consumers.

From the shareholders' perspective, these hedge contracts may make sense for their own sake, whether or not the Company includes their cost in the Net Power Costs calculation. If the Company experiences another low hydro year, the Aquila contract will compensate the company, covering part of the cost of higher-cost substitute power. In other words, PacifiCorp's shareholders might well purchase the hedge contracts whether or not the Commission includes the contract costs in rates.

For these reasons, the Commission should not be concerned about the "message" sent by excluding the costs of hedges in this base power case.

Q Please describe your proposed adjustment related to the WAPA contract.

A In 1962 Utah Power and Light negotiated a wheeling contract with WAPA with an 80-year term. The contract contained no provision for escalation over time. In 1983 the Commission adopted a policy of imputing revenue from that contract equal to the FERC tariffed wheeling rate. In its filing, PacifiCorp proposes to drop the imputation requirement, arguing that the wheeling contract has an offsetting value to the system that eliminates the need to impute revenues as if the contract's price had tracked the FERC wheeling rate.

The Company made a similar argument in its 1999 rate case. However, in its decision in that case, the Commission reaffirmed its long-standing policy and ordered the Company to impute revenues to the wheeling contract. Here is an excerpt from the 2000 order:

> In Docket No. 82-035-13, Report and Order issued May 23, 1983, this Commission recognized that the contracts were not compensatory and ordered an imputation of revenues, based on the

> then-current Federal Energy Regulatory Commission (FERC) wheeling rate of $24.12, to prevent the subsidy that otherwise would flow from Utah Power's retail customers to CRSP preference customers. Revenue imputation for these WAPA contracts has been the Commission's policy since then.
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> * * *
>
> We are unable to agree that the benefits allegedly enabled by these contracts outweigh costs ratepayers, in the absence of an imputation of revenues, would bear because of them. Without explicitly ruling on the Division's testimony that the Company behaved imprudently by entering long-term contracts having no escalation provisions, we conclude that the record contains no basis upon which to adopt the Company's rationale for abandoning the imputation policy, and we will not do so. The imputation policy is reaffirmed, and the Division - Committee adjustment is accepted.[1]

Q What about the Company's argument made in this case about the value of the contract?

A I think the Company's argument misses the point. Without analyzing the alleged value to the system brought about by the wheeling contract, it is still true that the contract rate is far below cost and market prices for wheeling. Had the Company negotiated a contract that appropriately escalated over time with the wheeling market and the Company's changing costs, the price today for the contract would likely be in the range of the FERC rate. Whatever benefits that may or may not flow from the presence of the contract would still be available. In other words, the Company has not shown in this case that, but for the below-market price of the wheeling contract, it would not have obtained the benefits it alleges.

[1] Commission Report and Order, Docket No. 99-035-10, Issued May 24, 2000.

For these reasons, AARP urges the Commission to maintain its practice of imputing revenue to the WAPA contract. I have prepared Exhibit RJB-3, page 2 to compute the WAPA adjustment. The revenue imputation reduces the Utah revenue requirement by $2.06 million.

Q. Please describe your proposed adjustment to expenses related to incentive compensation.

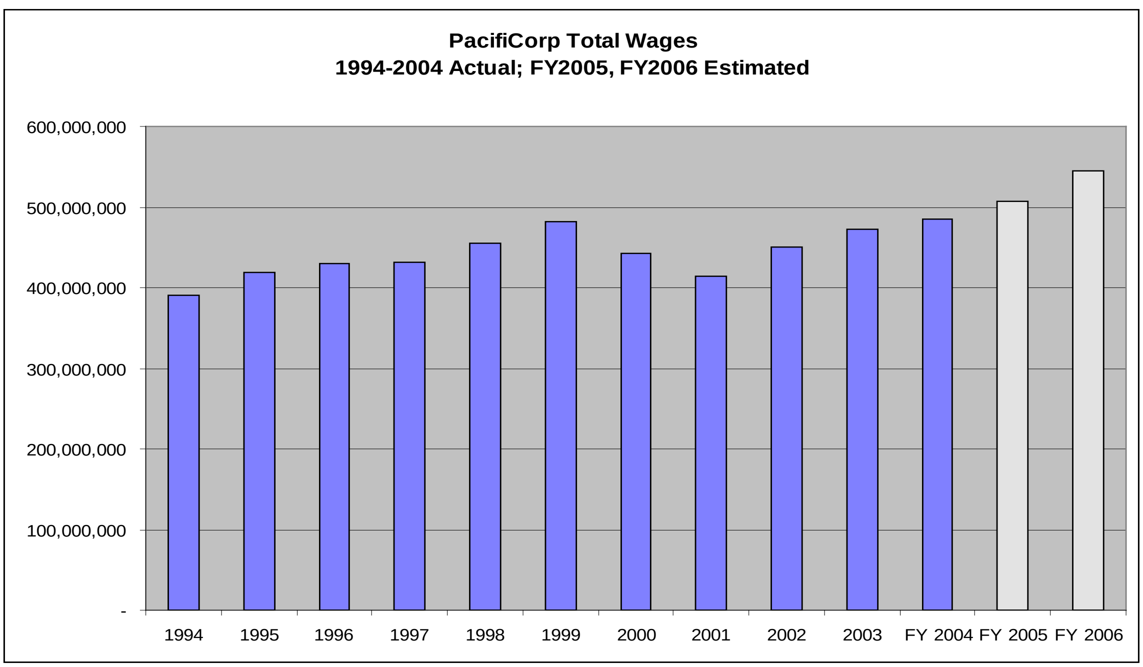
A. PacifiCorp has a program of incentive compensation called the Annual Incentive Program or AIP. The compensation under the incentive plan is based on several performance factors, including customer satisfaction, quality of service and corporate financial performance. The Company estimates that the AIP payout for the test year will be $33.4 million, of which $14.0 million will be allocated to Utah.

I think the appropriate regulatory treatment of these incentive payments is to split them between ratepayers and shareholders. I recommend that the Commission include the cost of these incentive compensation packages to the extent that the incentives are paid to improve performance that benefits consumers. The portions of the incentive payments that are tied to corporate performance will primarily benefit shareholders and are not of direct benefit to consumers. In my opinion, that portion should not be included in rates.

I have reviewed the 2005 AIP report cards used by the Company to award compensation for each of the business groups. I believe it would be appropriate for the Commission to include approximately 60% of the estimated payout for AIP in the test year. I have prepared Exhibit RJB-4 that details this sharing of incentive compensation payments made during the test period. As shown on Page 1 of that exhibit, the adjustment reduces the test year revenue requirement by $4.5 million.

Q Please discuss the labor costs projected by PacifiCorp for the future test year.

A PacifiCorp is projecting a wage expense of $544,477,000 for the 12-month period ending on March 31, 2006. This estimate is comprised of budget estimates for both employee headcount and wage rates, some of which are set by union contracts. It is important to place this total wage cost in perspective. The following graph shows the total company wages for each calendar year since 1994, with estimates for FY 2005 and FY 2006.



At first blush, it might appear that the projected total wage costs are consistent with a trend. But that analysis would be misleading. The apparent “trend” is somewhat self-fulfilling since the labor costs for FY 2005 and FY 2006 are both projected: consider that the “trend” from 1999-2001 was actually in the opposite direction.

Q If PacifiCorp’s energy sales continue to grow and employees continue to receive wage increases, isn’t it reasonable to assume that total wage costs will grow similar to the projections?

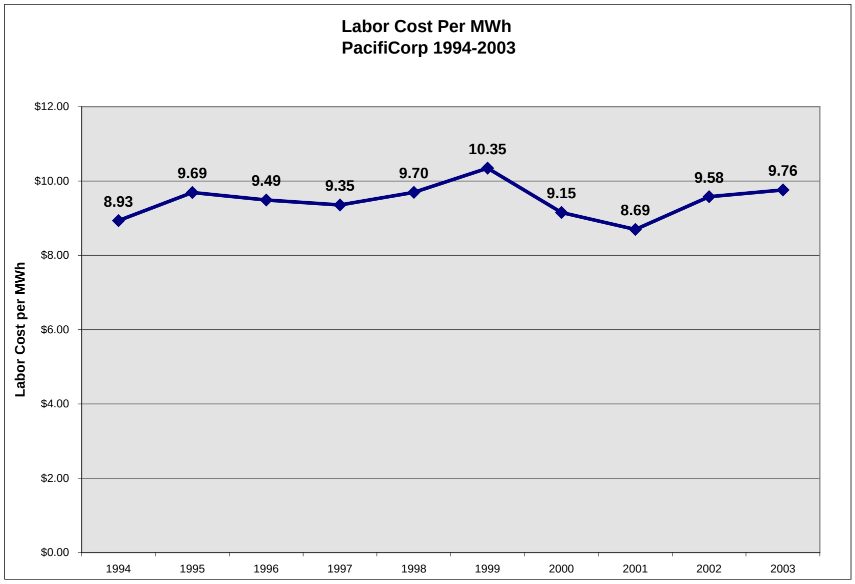
A Not necessarily. Increases in wage rates in any industry can be partially or fully offset by increases in worker productivity. In recent years, US labor productivity has exceeded the rate hourly wage growth. In other words, workers are being paid more per hour, but are accelerating their output at an even faster pace. The result of these competing trends is lower cost per unit produced, even though wages have grown.

Labor productivity can increase for lots of reasons. The main contributor is probably that workers are continuously provided better tools: more powerful computers, better software, improved information systems, better telecommunications facilities, etc.

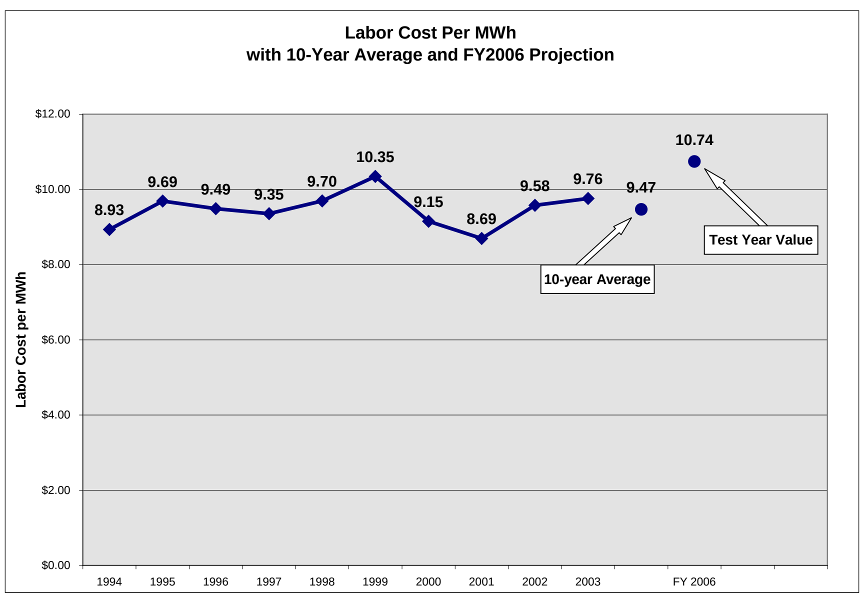
The proper way to test PacifiCorp’s estimate of growth in total labor cost is to analyze the trend in output per dollar of wages. That analysis shows that the FY 2006 future test year estimate of total wages is too high. Stated another way, PacifiCorp’s estimates of future total wages fails to consider the effect of increases in labor productivity.

Q How has PacifiCorp’s labor cost per unit of output changed in the past?

A The total cost of labor per system megawatt-hour sold has remained in a relatively small range for the past five years. The following chart illustrates labor cost per MWh for PacifiCorp since 1994:



By inspection, one can see that there is a relative consistency to this ratio. Now consider how the implied FY 2006 cost per MWh compares to this historic data:



As one can see, the projected cost per MWh in FY 2006 is projected to rise to the highest level in PacifiCorp's history. The value is projected to be $10.74 per MWh, which is 13.4% above the 10-year average of average cost of $9.47. Importantly, the labor cost has exceeded $10.00/MWh only once in the past ten years.

Q How should the Commission use this information to assess the Company's estimate of FY 2006 labor costs?

A The data show that PacifiCorp has overestimated its labor cost for FY 2006. The essential error is not considering that the Company's labor will be more productive in future periods than today. The estimation error may be difficult to trace and is probably buried in Company budget projections. I suspect that it probably takes the form of a higher projected employee headcount than will actually be required in FY 2006. In any event, there is strong reason to believe that PacifiCorp's cost of labor per unit output will not jump from historic levels as the Company projects.

Q Have you calculated an appropriate adjustment to reflect the effect of increased productivity of labor?

A Yes. Exhibit RJB-4, page 4 calculates the Company's projected labor costs for FY 2006 assuming that it maintains the labor cost per MWh that it achieved during 2003. This value is $9.76/MWh. This is a conservative approach since this rate is above the 10-year average of $9.47 and well above the average of the past three years, which is $9.34/MWh. As shown in the exhibit, this adjustment to projected labor costs reduces the Company's Utah revenue requirement by $20.7 million.

Q Mr. Binz, is your proposed adjustment to projected labor costs "known and measurable" adjustment?

A When setting rates on the basis of a future test period, it is no longer possible to construct a test year based on "known and measurable adjustments" to an historic period. That said, I think that my proposed adjustment to labor costs is more nearly "known and measurable" than the Company's own budgeted estimate of labor costs for FY 2006. This is because the theory behind the adjustment – that future labor costs per unit will reflect productivity gains – is unassailable and the historic data on which the adjustment is based are known and measurable.

As I stressed earlier, the difficulty of using future test period lies in the fact that the Commission must judge the reasonableness of numerous projections. If the Commission is willing to accept the Company's use of a future test period, it must ensure that the projections represent an accurate portrayal of what that future period will yield. Central to this task is matching changes in one component (e.g., energy sales) with the major inputs to that component (e.g., labor costs). Unless this matching principle is upheld, the resulting rates set by this Commission will be biased in one direction or the other. In the case of this filing, it seems clear that the Company's FY 2006 projections substantially overstate the cost of the labor required to produce the level of retail sales projected by the Company.

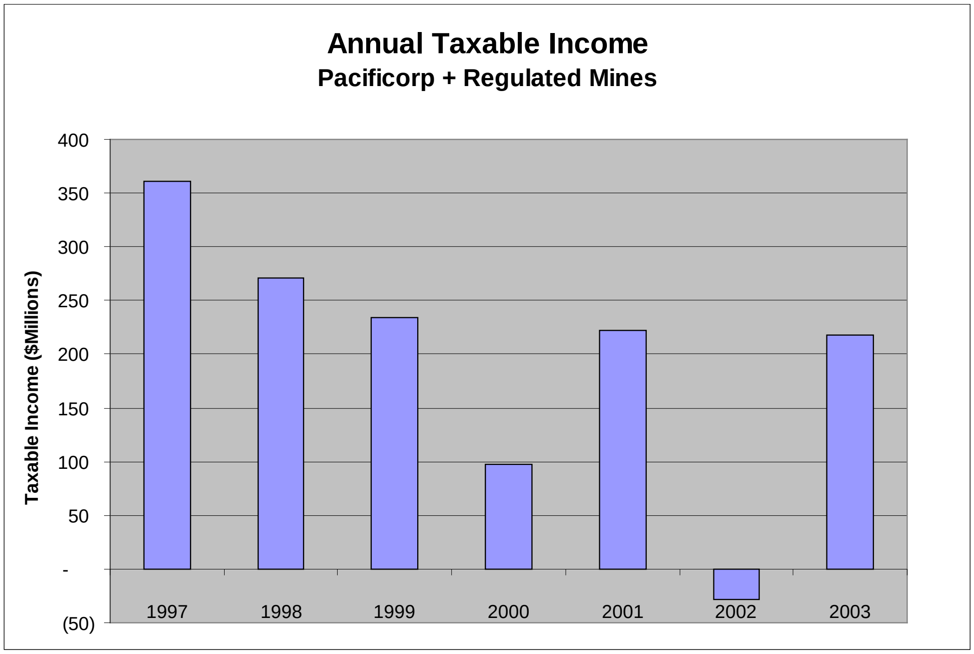
Q Please discuss your concern with the income tax expense claimed by PacifiCorp for the 2006 test period.

A In its filing, PacifiCorp includes an estimate of federal income tax expense calculated as if the Company files a stand-alone federal tax return. In other words, Mr. Weston calculates taxable income, applies the applicable Federal Income Tax rate of 35% and derives a tax liability. Because of the deferred income tax mechanism, the tax is not paid precisely as collected, but eventually PacifiCorp pays taxes that total the amount calculated by Mr. Weston.

But PacifiCorp does not file a separate tax return. It files a consolidated tax return along with its subsidiary companies and unregulated affiliates. This is done so that the parent corporation PacifiCorp Holdings, Inc. (PHI) can minimize its current tax liability. PHI is (eventually) a wholly owned subsidiary of Scottish Power.

Q How does a consolidated tax return minimize current tax liability for Scottish Power?

A In almost every year PacifiCorp contributes taxable income to the consolidated tax return. (A rare exception was 2002 in which PacifiCorp reported a loss.) The following graph shows the history of PacifiCorp's taxable income since FY 1997. I have included income reported by the regulated mine subsidiaries in the graph.



If each of PacifiCorp's affiliates in the holding company also reported taxable income, there would be little advantage to PHI in filing a consolidated tax return. However, certain of the affiliates consistently report losses, year after year. We will refer to these as "loss" companies.

When the consolidated return is prepared, the positive income of affiliates like PacifiCorp is totaled with the negative income of the loss companies. The resulting taxable income is used to compute the federal income tax actually paid by the collective entity. This strategy minimizes current taxes since, if the loss companies filed separately, they would not pay "negative" income taxes. In other words, the tax losses generated by the loss companies are not useful except to offset the positive income of the profitable subsidiaries.

What this means in practice is that PacifiCorp collects taxes at one level (and conveys those revenues to the parent company in the form of profits) but the parent entity pays less in total tax than the amount collected by PacifiCorp. Stated another way, the regulated company, by virtue of its profitability, lowers the tax liability of the parent. Unfortunately for ratepayers, this beneficial arrangement is not shared with the regulated company—there is no adjustment in this filing to reflect a portion of the tax loss savings made possible by the consolidated tax filing. As stated by Mr. Weston in response to a data request from the Committee of Consumer Services,

> Tax savings resulting from the taxable losses and/or tax credits of non-regulated companies have not been included in our rate filing. Ratepayers have not shared in the costs associated with the taxable losses and/or tax credits of the nonregulated entities and therefore are not allocated tax benefits derived from the associated costs.

The complete response from the data request is included as Exhibit RJB-4, page 2.

Q Are the benefits to Scottish Power of the consolidated tax return significant?

A Yes. I estimate that Scottish Power saves more than $100 million in a typical year by using a consolidated tax return, compared to the case of stand-alone tax returns for each entity in PHI. The profitability of PacifiCorp makes much of that benefit possible by providing taxable income against which the losses of other subsidiaries can be offset. The entire value of that tax benefit is retained by PHI. If a reasonable share of the benefit were allocated back to PacifiCorp, rates could be lowered for the consumers who pay rates that collect the “phantom” taxes that are collected by not actually paid.

Q Have you estimated the value to Utah rates if an equitable distribution of the consolidated tax benefits were returned to PacifiCorp?

A The tax returns of PHI and its predecessor NA General Partnership are considered Highly Confidential by PacifiCorp and were made available for inspection only at the Company's offices. I was not able to travel to PacifiCorp's offices to view the tax returns that would allow me to make an exact calculation. However, I have prepared an estimate of the reasonable allocation of the tax benefits based on non-confidential data supplied by PacifiCorp in response to Data Request CCS 19.11(a) of the Committee of Consumer Services. This analysis is included as Exhibit RJB-4, page 4.

Q Please explain this exhibit.

A My analysis shows that a conservative estimate of the tax benefits to PacifiCorp Holdings, Inc. from the filing of a consolidated tax return averages are quite large. I estimate the FY 2001 tax savings to be at least $116 million and the FY 2002 savings to be at least $126 million. (See line 14 of Exhibit RJB-4, page 4).

As discussed above, if savings from the consolidated tax return were allocated to the profit-making entities that make those savings possible, the regulated utility PacifiCorp would be allocated a substantial fraction of the tax savings. On average, I estimate the allocated savings to PacifiCorp, based on its share of profits earned by the non-loss companies, would average from $37 million to $49 million annually. The corresponding portion allocated to Utah would be $15.2million to $20.3 million for the test period, depending on how the historic average is calculated.

Q What is your recommendation on this issue?

A I recommend that the Commission reduce the federal income tax expense allowed for ratemaking by an amount that reflects the value of PacifiCorp's taxable gains to the its holding company owner.   A reasonable estimate of this adjustment is a reduction in the Utah revenue requirement of $20 million in those years in which PacifiCorp achieves a normal profit.

I have prepared my estimate on the basis of non-confidential data that lumps together gains and losses of some of the PHI subsidiaries. A more precise calculation of the tax benefit calculation requires knowing the gains and losses of each subsidiary – data that is deemed highly confidential by PacifiCorp.

Q Does this adjustment improperly extend the Commission's regulation to the unregulated subsidiaries of PacifiCorp Holdings, Inc.?

A No. I suspect that PacifiCorp will argue that an adjustment to reflect the benefits of the consolidated tax filing improperly mixes regulation of utility and unregulated subsidiaries. But this argument misstates the basis for the adjustment. It is simply the case that PacifiCorp, with its consistent pattern of annual profits, brings to the consolidated tax return a reduction in the tax bill of the collected entities.

If the Commission adopts the consolidated tax adjustment, the Commission is only insisting that the utility PacifiCorp receive credit from the holding company PHI for this benefit. The practice of allocating or imputing the tax savings to the profitable entities does not regulate the unregulated subsidiaries any more than any other cost allocation rules specified by the Commission for affiliate transactions. These subsidiaries will continue to show a profit or a loss; the stand-alone tax bill of these subsidiaries will remain unchanged. Other states have successfully implemented an adjustment for consolidated tax savings and the Utah Commission should do so as well.

Q Please summarize your testimony.

A AARP does not object to the use of a future test period to set rates for PacifiCorp as long as the estimates of future investment, revenue and expenses reflect the likely future occurance. After reviewing the Company's testimony and exhibits, together with substantial amounts of information produced in discovery, I recommend the following adjustments to the Company's filing:

- The Commission should reduce the authorized return on equity capital from the current level of 10.7%.
- The Commission should adjust the Company's estimates of rate base by correctly reflecting the expense lag associated with the payments of interest on long term debt and dividends on preferred stock.
- The Commission should adjust the Company's estimate of net power costs by excluding the cost of the financial hedge and reinstating the WAPA wheeling adjustment.
- The Commission should adjust the Company's estimates of test year expenses:
    - Incentive compensation – The Commission should exclude a portion of incentive compensation related to corporate performance.
    - Projected salary expense – The Company has overstated labor expense for FY 2006 by failing to consider the effect of increased labor productivity.
    - The Commission should adjust the Company's claimed income tax expense to reflect the fact that PacifiCorp Holdings, Inc. files a consolidated tax return.

Q. Does this conclude your testimony?

A. Yes.

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Denver, Colorado 80220
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Employment History

1995-present President, Public Policy Consulting

Public policy consultant, specializing in energy and telecommunications issues. Assignments include strategic counsel to clients and research and testimony before regulatory and legislative bodies. Since 1995, a wide range of clients has included: consumer advocate offices, rural electric utilities, senior citizen advocacy groups, industrial electric users, homebuilders, telecommunications resellers, an incumbent local exchange company, low-income advocacy organizations, and municipal utilities.

1996-present President and Policy Director, Competition Policy Institute

Competition Policy Institute is an independent non-profit organization that advocates state and federal policies to bring competition to energy and telecommunications markets in ways that benefit consumers. Duties include: determining the organization's policy position on a wide range of telecommunications and energy issues; conducting research, producing policy papers, presenting testimony in regulatory and legislative forums, hosting educational symposia for state regulators and state legislators.

.1984-1995 Director, Colorado Office of Consumer Counsel

Director of Colorado's first state-funded utility consumer advocate office. By statute, the OCC represents residential, small business and agricultural utility consumers before state and federal regulatory agencies. The office has been a party to more than two hundred legal cases before the Colorado Public Utilities Commission, the Federal Communications Commission, the Federal Energy Regulatory Commission and the courts. Annual office budget is $1 million.

Managed a staff of eleven, including attorneys, economists, and rate analysts who conduct economic, financial and engineering research in public utility matters.

Testified as an expert witness on subjects of utility rates and regulation. Negotiated rate settlement agreements with utility companies. Regularly testified before the Colorado general assembly and spoke to professional business and consumer organizations on utility rate matters. Consulted with advisory board of consumer leaders from around the state.

Leadership role in National Association of State Utility Consumer Advocates. Member of high-level advisory boards to Federal Communications Commission (Network Reliability Council) and Environmental Protection Agency (Acid Rain Advisory Council). Frequent witness before congressional committees and invited speaker before national industry and regulatory forums.

1977-1984 Consulting Utility Rate Analyst

Represented clients in public utility rate cases and testified as an expert witness in more than twenty utility cases before regulatory commissions in Utah, Wyoming, Colorado and South Dakota. Clients included state and local governments, low income advocacy groups, irrigation farmers and consumer groups. Testimony spanned topics of telephone rate design, electric cost-of-service studies, avoided cost valuation of nuclear generation, electric rate design for irrigation customers and municipal water rate design.

1975-1984 Instructor in Mathematics

Taught mathematics at the University of Colorado, Denver and Boulder campuses. Nominated three times for outstanding part-time faculty member.

1971-1974 Manager, Blue Cross and Blue Shield

Managed major medical claims processing department. Responsibilities included budgets, hiring, training, managing supervisors, and coordinating with medical peer review committee.

Other Business Interests

1994-present Managing Partner, Trail Ridge Winery

Partner and Secretary/Treasurer of Trail Ridge Winery. Trail Ridge is a Colorado winery located in Loveland, Colorado, producing a variety of wines from Colorado-grown grapes. Duties include service on board of directors; duties of corporate secretary/treasurer; development of business plans; legislative, regulatory and other external affairs; assistance in winery operations and tasting room; assistance in public relations and marketing.

Education

M.A. (Mathematics) 1977. University of Colorado. Course requirements met for Ph.D.

Graduate courses toward M.A. in Economics 1981-1984. University of Colorado. Twenty-seven hours including Economics of Regulated Industries, Natural Resource Economics, Econometrics.

Advanced Course in Utility Regulation 1986. National Association of Regulatory Utility Commissioners.

B.A. with Honors (Philosophy) 1971. St. Louis University.

Diploma 1967. Catholic High School, Little Rock, Arkansas.

Professional Associations and Activities

Colorado Legislative Task Force on Information Policy, Gubernatorial Appointee 2000-2001

National Association of State Utility Consumer Advocates
President 1991-1992, Vice-President 1990, Treasurer 1987-1989
Chair, Telecommunications Committee 1992-1995

Network Reliability Council to the Federal Communications Commission

North American Numbering Council to Federal Communications Commission, Co-Chair

Harvard Electric Policy Group, John F. Kennedy School, Harvard University

Denver Mayor's Council on Telecommunications Policy

Exchange Carriers Standards Association Network Reliability Steering Committee

Colorado Telecommunications Working Group, Gubernatorial Appointee

Colorado Energy Assistance Foundation, Board Member, Past President

Legislative Commission on Low-Income Energy Assistance, Past President

Colorado Public Interest Research Foundation, Board Member

Colorado Common Cause, Board Member

Acid Rain Advisory Council to the Environmental Protection Agency

Outreach Committee, Western States Coordinating Council Regional Planning Committee

Total Compensation Advisory Council to the State of Colorado Department of Personnel

New Mexico State University Public Utilities Program, Faculty and Advisory Council

Aspen Institute for Humanistic Studies, Telecommunications Policy Meetings 1986-1997

Who's Who in Denver Business

Council on Economic Regulation, Past Fellow

Colorado Wine Industry Development Board, Chairman

American Vintners Association, Executive Committee, Membership Chair

Legislative and Congressional Testimony

United States House of Representatives Judiciary Committee, November 1999. Testimony concerning H.R. 2533, The Fairness in Telecommunications License Transfer Act of 1999.

United States Senate Judiciary Committee; Antitrust, Business Rights and Competition Subcommittee, April 1999. Testimony concerning S.467, The Antitrust Merger Review Act.

United States Senate Commerce Committee, Telecommunications Subcommittee, May 1998. Testimony in oversight hearings concerning the performance of the Common Carrier Bureau of the Federal Communications Commission.

United States Senate Judiciary Committee, Washington, D.C., September 1996. Presented testimony on behalf of the Competition Policy Institute on the competitive impact of proposed mergers of Regional Bell Operating Companies.

United States House of Representatives Subcommittee on Telecommunications and Finance of the Committee on Commerce, May 1995. Testimony presenting NASUCA's position on H.R. 1555 by Representative Fields.

United States Senate Subcommittee on Antitrust, Washington, D.C., September 1994. Testimony presenting NASUCA's position on S. 1822 by Senator Hollings.

United States House of Representatives Subcommittee on Telecommunications and Finance of the House Energy and Commerce Committee, Washington, D.C., February 1994. Presented testimony on H.R. 3636.

United States House of Representatives Subcommittee on Economics and Commercial Law, Washington, D.C., October 1992. Supplemental testimony presenting NASUCA's position on legislation concerning the Modified Final Judgment introduced by Representative Brooks.

United States House of Representatives Subcommittee on Telecommunications and Finance, Washington, D.C., October 1991. Testimony on RBOC entry into telecommunications manufacturing and information services.

United States House of Representatives Subcommittee on Economics and Commercial Law, Washington, D.C., August 1991. Testimony presenting NASUCA's position on possible federal legislation concerning the Modified Final Judgment.

United States Senate Subcommittee on Energy Regulation and Conservation, Denver, Colorado, April 1991. Testimony presenting NASUCA's position on federal legislation concerning regulation of the natural gas industry, introduced by Senator Wirth.

United States Senate Communications Subcommittee, Washington, D.C., February 1991. Testimony on behalf of NASUCA concerning S.173, telecommunications legislation introduced by Senator Ernest Hollings.

United States Senate Communications Subcommittee, Washington, D.C., July 1990. Testimony on behalf of NASUCA concerning S.2800, telecommunications legislation introduced by Senator Conrad Burns.

United States House of Representatives Subcommittee on Telecommunications and Finance, July 1988. Testimony on the FCC Price Cap proposal.

Georgia State Legislature Interim Committee on Natural Gas Competition. Fall 1996. Testimony on the consumer impacts of restructuring the natural gas industry in Georgia.

Iowa General Assembly, Des Moines, Iowa, November 1992. Testimony on legislation concerning incentive regulation.

American Legislative Exchange Council, November 1999. "The Changing Role of Public Utilities Commissions"

American Legislative Exchange Council concerning Rights-of-Way and Competition in Telecommunications, July 1998.

American Legislative Exchange Council Committee on Rights of Way. May 1998. Testimony on rights of way policies, taxation and telecommunications development.

Colorado State Senate and Colorado House of Representatives 1984-1995. Frequent witness on variety of energy and telecommunications issues.

Publications

Mr. Binz is the co-author of two major reports on electric industry restructuring:

Navigating a Course to Competition: A Consumer Perspective on Electric Restructuring

and

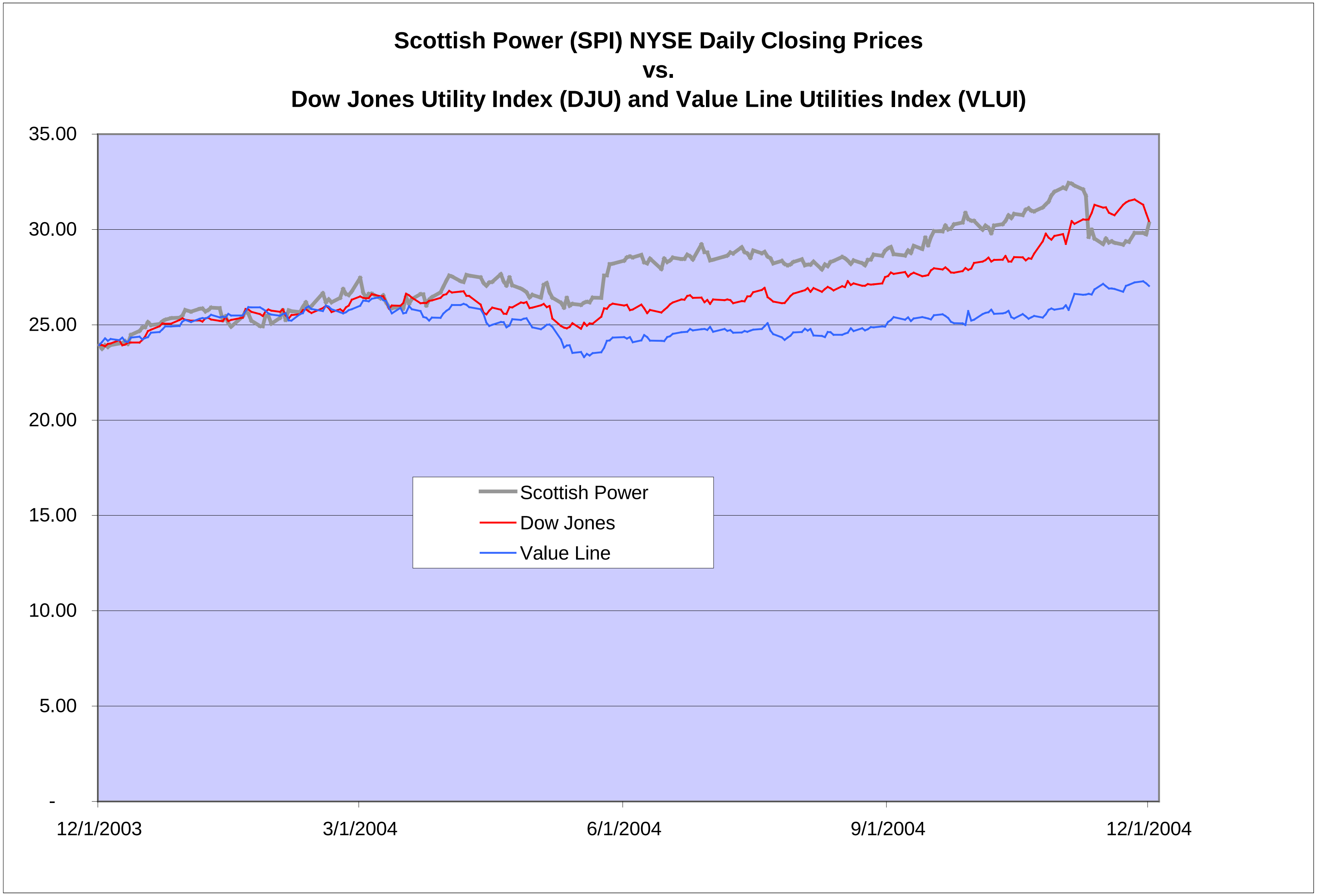
Addressing Market Power: The Next Step in Electric Restructuring.

In the telecommunications area, Mr. Binz recently completed a major discussion paper entitled ***Qwest, Consumers and Long Distance Entry: A Discussion Paper.***

These publications are available at the Public Policy Consulting website: www.rbinz.com.

Revenue Effect of a 100 Basis Point Change in Return on Equity
based on PacifiCorp Filed Case

Filed Rate Base (from ROO, Page 1.0)	$3,115,986,794
Change in Cost of Equity	1.00%
Change in Weighted Cost of Capital	0.478%
Change in Income	$ 14,894,417
Revenue Multiplier	1.625
Change in Required Revenue	$ 24,203,427


Scottish Power (SPI) NYSE Daily Closing Prices
vs.
Dow Jones Utility Index (DJU) and Value Line Utilities Index (VLUI)
35.00
30.00
25.00
20.00
15.00
10.00
5.00
-
12/1/2003
3/1/2004
6/1/2004
9/1/2004
12/1/2004
Scottish Power
Dow Jones
Value Line

Cash Working Capital Adjustment

Offset to Cash Working Capital -- Inclusion of Long Term Debt Interest and Preferred Stock Dividends
Rate Base Adjustment

Line No.

		Long Term Debt	Preferred Stock	Total	Explanation
(1)	Utah Rate Base	3,115,061,495	3,115,061,495		JTW-1, page 2.2
(2)	Weighted Cost	3.335%	0.080%		JTW-1, page 2.1
(3)	Capital Cost	103,887,301	2,492,049		Line (1) times Line (2)
(4)	Expense per day	284,623	6,828		Line (3) divided by 365
(5)	Revenue Lag Days	44.82	44.82		JAM 06 UT MSP - Sheet "Variables"
(6)	Expense Lag Days	91.25	45.625		Interest paid semi-annually; dividends paid quarterly
(7)	Net Lead or Lag Days	(46.4)	(0.8)		Line (2) times Line (3)+Line(3.5)
(8)	Working Capital Adjustment	(13,215,034)	(5,496)	(13,220,530)	Line (4) times Line (5)
(9)	**Rate Base Adjustment**			**(13,220,530)**	

Adjustment to Impute Revenues to WAPA Wheeling Contract

Adjustment to Remove Hydro Hedge Contract From Net Power Costs

Adjustment to Net Power Costs
Remove Costs of Aquila Hydro Hedge

Description	Account	Total Company	Factor	Factor %	Utah Allocated
Remove Aquila Hydro Hedge	NPC	(1,750,000)	SG	41.9081%	(733,392)
Total Adjustment to Utah Net Power Costs					(733,392)

Adjustment to Impute Revenues to WAPA Wheeling Contract

Adjustment to Revenues
Other Electric Revenues
WAPA Wheeling Contract Revenue Imputation

	FY00	FY01	FY02	FY03	FY04
Peak KWh	3,875,905	3,884,662	3,715,031	3,773,126	3,717,010
Monthly Price (FERC Tariff)	$ 2.0250	$ 2.0250	$ 2.0250	$ 2.0250	$ 2.0250
Imputed Revenue	$ 7,848,708	$ 7,866,441	$ 7,522,938	$ 7,640,580	$ 7,526,945
Actual Billed Revenues	$ 2,651,246	$ 2,669,580	$ 2,863,484	$ 2,820,073	$ 2,811,577
Discounted Revenues	$ 5,197,461	$ 5,196,860	$ 4,659,454	$ 4,820,507	$ 4,715,368
SG Allocator	0.419081	0.419081	0.419081	0.419081	0.419081
Utah Allocated	$ 2,178,157	$ 2,177,905	$ 1,952,689	$ 2,020,183	$ 1,976,121
Five Year Average	$ 2,061,011				

Adjustment to Expenses to Reflect Changes to Incentive Compensation Expense

Adjustment to Expenses
Remove 40% of Executive and Officer Incentive Compensation

Description	Account	Total Company	Factor	Factor %	Utah Allocated
Utah Allocated Incentive Compensation		33,403,789	SG	41.908%	13,998,893
Officer and Exempt Employee Share					11,248,921
Adjustment to Expenses Remove 40% of Officer and Exempt Incentive Compensation					(4,499,568)

Adjustment to Labor Costs to Reflect Increase in Labor Productivity

Offset to Projected Labor Costs to Reflect Increased Labor Productivity
Expense Adjustment

Line No.			**Explanation**
(1)	Projected FY 2006 Labor Cost	544,547,877	JTW-1, Page 4.17.9
(2)	Projected FY 2006 System Sales	50,695,644	Response to DR CCS 1.144
(3)	Projected Labor Cost per MWh	10.74	Line (1) divided by Line (2)
(4)	Historic Labor Cost per MWh	9.76	Calculated from FERC Form 1 Data
(5)	Difference	(0.98)	Line (4) minus Line (3)
(6)	Productivity Adjustment	(49,758,387)	Line (2) times Line (5)
(7)	Utah Allocation Factor (SO)	0.416087	JTW-1, Tab 10
(8)	Utah Adjustment	(20,703,818)	Line (6) times Line (7)
(9)	**Expense Adjustment**	**(20,703,818)**	

PacifiCorp Response to CCS Data Request 19.12

04-035-42/PacifiCorp
October 21,2004
CCS 19th Set Data Request 19.12

CCS Data Request 19.12

Explain how PacifiCorp has recognized consolidated tax savings in its rate filing. If consolidated tax savings have not been recognized, explain why not and identify the Company witness or witnesses responsible for addressing federal income tax issues.

Response to CCS Data Request 19.12

Tax savings resulting from the taxable losses and/or tax credits of non-regulated companies have not been included in our rate filing. Ratepayers have not shared in the costs associated with the taxable losses and/or tax credits of the nonregulated entities and therefore are not allocated tax benefits derived from the associated costs. We have included the taxable losses and/or tax credits of all the regulated companies.

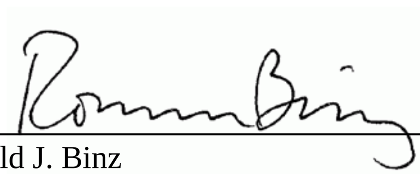
The Company has not identified which witness if any will be required to address Federal tax issues in this proceeding.

Allocation of Consolidated Tax Benefits

Line	Entity:	Year: 3/31/2000	3/31/2001	3/31/2002	3/31/2003	4-year Avg	3-Year Avg
1	NA General Partnership	478,774	(332,569,171)	(360,841,973)	(239,167,792)		
2	PacifiCorp Holdings, Inc.			(810,039)	534,399		
3	PacifiCorp, Inc.	87,412,826	206,317,494	(30,412,091)	202,745,127		
	Regulated Mines:						
4	Pacific Minerals, Inc.	9,715,982	23,293,300	15,861,238	15,573,159		
5	Glenrock Coal Co.	(81,397)	(659,460)	(150,396)	0		
6	Centralia Mining Co.		(6,518,316)	0	0		
7	Energy West Mining Co.		(367,216)	(14,987,324)	0		
8	Interwest Mining Co.		(183,489)	1,098,850	0		
	Nonregulated Subsidiaries:						
9	Total, Nonregulated Subsidiaries	52,402,671	81,616,702	226,871,454	41,038,627		
10	Total	149,928,856	(29,070,156)	(163,370,281)	20,723,520		
11	Eliminations & Adjustments	0	(19,745,649)	(8,268,776)			
12	Subtotal	149,928,856	(48,815,805)	(171,639,057)	20,723,520		
13	Total of Losses	(81,397)	(332,569,171)	(361,652,012)	(239,167,792)		
14	Tax Effect for PHI	(28,489)	(116,399,210)	(126,578,204)	(83,708,727)		
15	Total of Gains	150,010,253	311,227,496	242,732,692	259,891,312		
16	PacifiCorp Gains	87,412,826	206,317,494	0	202,745,127		
17	PacifiCorp Share of Total of Gains	58.3%	66.3%	0%	78.0%	**4-year Avg**	**3-Year Avg**
18	PacifiCorp Allocated Tax Losses	(47,431)	(220,465,219)	0	(186,578,397)	(101,772,762)	(135,697,016)
19	From Wyoming Case (D. Peterson Testimony)	(19,335,907)	(218,341,288)	0	(186,578,397)	(106,063,898)	(141,418,531)
20	Tax Rate	35%	35%	35%	35%	35%	35%
21	PacifiCorp Allocated Tax Savings	(6,767,567)	(76,419,451)	-	(65,302,439)	(37,122,364)	(49,496,486)
22	Utah Allocation Factor	41%	41%	41%	41%	41%	41%
23	Utah Allocated Tax Savings	(2,774,703)	(31,331,975)	-	(26,774,000)	(15,220,169)	(20,293,559)

The foregoing ***Testimony of Ronald J. Binz on Behalf of AARP*** was prepared by Ronald J. Binz and is respectfully submitted to the Utah Public Service Commission on this 3rd day of December, 2004.

(signed)



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