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

A. My name is Donald N. Furman. My business address is 825 NE Multnomah, Suite 2000, Portland, Oregon 97232. My present position is Senior Vice President, Regulation and External Affairs.

Qualifications

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Arts degree in economics from Northwestern University and a Juris Doctorate degree from Lewis and Clark Law School. Before assuming my present position with PacifiCorp, I served as Vice President of Transmission, Vice President of Domestic Business Development, and President of the Company's unregulated power marketing subsidiary.

Q. What are your responsibilities as Senior Vice President, Regulation and External Affairs?

A. I oversee all regulatory matters, including rate cases, before six state utility commissions and the Federal Energy Regulatory Commission. I am also responsible for all of the Company's government relations activities at both the state and federal level.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. My testimony describes changes in PacifiCorp's situation that make this filing necessary. The Company faces high and fluctuating costs together with a need for sustained and increased levels of new capital investment. The combination challenges our ability to provide safe and reliable service at a reasonable cost and this situation is likely to persist. We are presently earning only about 3.5 percent on our equity capital. Now is the time for the Commission and the Company to work together and address these issues. While the challenge is new, the basic principles are not. My testimony reviews traditional ratemaking principles and applies them in the form of new regulatory mechanisms that will help deal with this situation on an ongoing basis.

This filing requests a significant increase in rates, nearly 18 percent. I introduce the testimony of other Company witnesses who explain the cost increases that have led to this rate request and I describe actions that PacifiCorp has taken to keep prices low.

PacifiCorp's Situation

Q. Please describe the extent of the changes affecting PacifiCorp.

A. The crisis in Western power markets in 2000 and 2001 changed the electricity industry. At the same time, related markets for other forms of energy changed as well. The after-effects have continued to ripple through the entire energy sector. Compared to the period of the late 1990s:

- Energy costs are now higher and more volatile;
- Environmental concerns and a strengthening economy require more investment in electricity generation;
- Third parties are less able to finance generation projects without utility backing;

- Reliable service requires more investment in transmission and other infrastructure;
- Interest rates are rising; and
- Accounting rules have changed, putting more pressure on utility financial statements.

In addition, many companies like PacifiCorp also face increases in the general cost of doing business, such as for pensions and benefits.

I will discuss each of these important developments in turn. The consequence is that in order to provide reliable service at reasonable cost, PacifiCorp is required to commit substantial amounts of new capital but our ability to do so is under increased pressure.

Q. Are energy costs now higher and more volatile?

A. Yes, today's high energy costs are easy to see in everyday life. It is important to understand that this situation is likely to persist. The 2005 Biennial Energy Report: Issues and Analysis for the Washington State Legislature and Governor[1] summarized the situation this way:

> "Since 1999, average electricity prices have increased by a third, gasoline has increased over fifty percent, and natural gas has doubled. Petroleum and natural gas prices have been driven higher by numerous domestic and international events ranging from hurricanes in the Gulf Coast to rapidly increasing petroleum demand in China and India, to more rapid decline in natural gas well production than originally predicted. Overall, the supply situation for both natural gas and petroleum has and will likely remain tight which is reflected in higher market prices for both commodities." (Section 1, Page 3)

[1] State of Washington, Department of Community, Trade and Economic Development (CTED). See http://qa.cted.wa.gov/_CTED/documents/ID_1872_Publications.pdf

In an article in the Vancouver Daily Columbian dated January 23, 2005,[2] Terry Morlan, Manager of Economic Analysis for the Northwest Power and Conservation Council, said:

> "[T]he region and nation are facing the greatest energy pessimism since the oil embargo of 1973.
>
> Turmoil in the Middle East that has contributed to high oil prices does not appear to have much hope of diminishing anytime soon.
>
> Many analysts of the domestic situation now expect that production of conventional natural gas in North America may be near its peak and unable to meet the needs of a growing economy. That is what happened to domestic oil production around 1970. Unconventional natural gas supplies, pipeline gas from Alaska, and imported natural gas in liquefied form (LNG) will be more expensive and take several years to come on line.
>
> In the meantime, natural gas prices are expected to remain high and volatile, exhibiting extreme sensitivity to weather and storage level variations."

Volatile prices for other forms of energy affect wholesale electricity prices. Even after the end of the Western energy crisis of 2000 and 2001, wholesale power prices have fluctuated markedly. The Direct Testimony of Mark Widmer shows how the volatility of PacifiCorp's power costs has increased in recent years.

Q. Without new regulatory mechanisms, how does this volatility affect PacifiCorp?

A. A large increase in cost reduces PacifiCorp's financial resources just as it would for any other company. A large increase in costs can:

- Put pressure on deferrable programs;
- Increase the need for borrowing; and
- Reduce PacifiCorp's attractiveness to potential creditors and equity investors, further increasing the cost of obtaining funds.

[2] http://www.columbian.com/working/forecast/energy.cfm

PacifiCorp buys a lot of energy so volatility in energy costs has a company-wide impact. Mr. Widmer shows that PacifiCorp's Net Power Costs, primarily composed of fuel and purchased power costs net of wholesale energy sales revenue, are approximately $830 million per year for the Company as a whole. PacifiCorp has total annual retail sales of approximately $2,500 million. Power costs are between one-third and one-fourth of the total revenue requirement and increases have a correspondingly large impact.

Many of PacifiCorp's non-power costs are fixed and others, while not fixed, cannot easily be reduced without affecting service. Large construction projects can require several years to complete. Additionally, PacifiCorp's system requires ongoing maintenance and customer service. Large cost fluctuations make management of these programs more difficult and may reduce the Company's ability to deliver the level of service that our customers would wish.

Q. Earlier you stated that environmental concerns and a strengthening economy require substantial investment in electricity generation. Please describe the environmental concerns to which you were referring.

A. There are two main areas of environmental concern: air emissions and relicensing our hydroelectric facilities. Regarding the first, PacifiCorp estimates that it will spend between $500 million and $1.7 billion on capital and expenses related to emission controls between now and 2025. The majority of PacifiCorp's existing generation is fueled by coal. Coal has provided our customers with power at low and stable costs for many years but environmental regulations now require substantial investments to reduce emissions. The cost will depend on the particular technologies that environmental regulators require. Costs could be higher than the estimate since it does not consider the cost of potential regulations to reduce carbon dioxide emissions. This issue and the Company's response to it are described in PacifiCorp's 2004 Integrated Resource Plan (IRP), which was filed with the Commission in January 2005 (Docket No. UE-050095).

Q. Are these costs reflected in the present rate request?

A. No. Standard regulatory practice allows PacifiCorp to begin recovery in rates only when investments are made and the equipment goes into service. PacifiCorp finances investments using a combination of internal funds and borrowing.

Q. Your estimate of the costs of air emission control costs covered a period of twenty years. Are these costs a distant concern?

A. No, work is already beginning. In July 2004, PacifiCorp approved a project that will update and improve emission controls on its Huntington Unit 2, a 450 megawatt coal-fired power plant. Construction will have begun by the time this proceeding is concluded.

Q. You mentioned that PacifiCorp is relicensing its hydroelectric facilities.

A. Yes. PacifiCorp is in the process of relicensing a number of its hydroelectric projects. The IRP states that PacifiCorp has incurred over $54 million of process costs alone. New requirements contained in FERC licenses or decommissioning orders could cost over $2 billion over the next 30 to 50 years. In addition, relicensing may result in operational restrictions that could increase net power costs. About 90 percent of these relicensing costs relate to PacifiCorp's three largest projects: Lewis River, Klamath River and North Umpqua.

Q. Is PacifiCorp planning to acquire new sources of electricity?

A. Yes, in fact the Company is already acquiring new resources. PacifiCorp has recently committed to the acquisition of natural gas-fired generating capability in Utah, wind generation in Oregon and Idaho, long-term purchased power contracts, and the output of large PURPA qualifying facilities in Utah. These acquisitions are discussed in the Direct Testimony of Mark Tallman. Exhibit No.__(DNF-2), taken from PacifiCorp's IRP, illustrates the need for new resources now and over then next ten years. In total, we are presently in the process of adding approximately 2,300 megawatts of resources to the system. In addition, the IRP calls for the acquisition of some 2,600 megawatts of generation and purchases plus approximately 200 megawatts of load control programs. Not shown in the chart are approximately 230 average megawatts of energy conservation that we have acquired and 200 average megawatts to be additionally acquired over the next ten years.[3] New IRP generation, excluding the resources that PacifiCorp is presently acquiring, is expected to require capital investment of $2.67 billion in inflation-adjusted 2004 dollars.[4]

Q. What is causing the need for new generation?

A. The economy is growing again and consumers are using more power. In addition, a number of PacifiCorp's existing long-term power purchase contracts will expire and need to be replaced. The IRP concludes that PacifiCorp's energy sales will

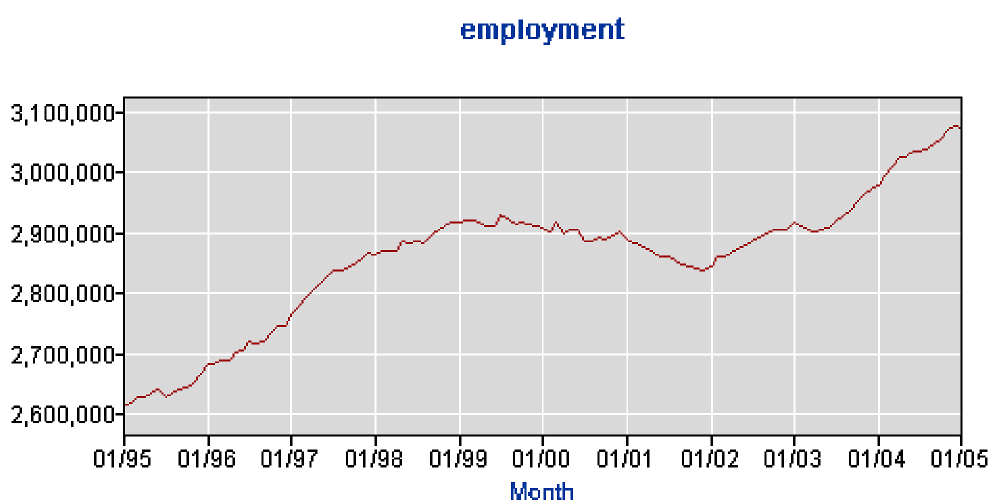
[3] Energy conservation programs are not shown because the IRP models them as reductions in energy sales and not as new resources. Nonetheless, they are an important part of the plan. See the IRP Technical Appendix, page 44.

[4] IRP Technical Appendix, page 71.

grow by 2.1 percent per year over then next ten years.[5] This compares to growth of only 1.3 percent per year from 1991 to 2003. Loads are expected to become more heavily concentrated on peak hours as well. Peak loads are expected to grow at 3.0 percent per year over the next ten years, a total increase of over 2,100 megawatts. At the same time, the capability of existing resources is expected to fall by approximately 2,300 megawatts, due mostly to the expiration of purchase contracts.[6]

Q. You mentioned that the economy is growing.

A. Yes. Economic growth is evident nationally and throughout PacifiCorp's service area. The rebound of the economy in Washington State is particularly striking. The following chart shows total employment in Washington State.[7]



[5] See PacifiCorp's IRP, page 44.
[6] As shown in Exhibit No.__(DNF-2).
[7] Source: U.S. Bureau of Labor Statistics, http://data.bls.gov/PDQ/servlet/SurveyOutputServlet?series_id=LASST53000005&data_tool=%22EaG%22

Total employment retreated in 2000 and 2001 but has come back strongly since. The most recent state economic forecast predicts continued strong employment growth through the end of 2007.[8] PacifiCorp's IRP forecasts that peak electricity load will continue to grow in our Washington service area at a rate of 1.8 percent per year. Economic growth means jobs for the citizens of the state. Continued growth requires a reliable energy infrastructure to support it and that requires utility investment.

Q. Could investments in new generation be avoided by an aggressive program of energy conservation and renewable resources?

A. No, but they can help. PacifiCorp's current IRP calls for substantial acquisition of energy conservation and renewable resources. Those resources, while important, have limited ability to meet our energy needs. To the extent that they are economically available, renewable resources like wind resolve PacifiCorp's acquisition challenge to only a limited degree because we need to acquire 100 MW of wind for every 20 MW of capacity requirement. The cost is uncertain because of uncertainty surrounding Federal production tax credits for wind power and uncertainty about the operational impact of adding large amounts of intermittent resources. Wind is one of the alternatives but not a complete solution.

Conservation, coupled with a mechanism for promptly recovering its costs such as Washington's System Benefits Charge, can make a real contribution. I

[8] Washington State Office of the Forecast Council, Preliminary February 2005 Economic Forecast, http://www.erfc.wa.gov/pubs/t0205.pdf

discuss regulatory mechanisms to support energy conservation programs, among other things, later in my testimony.

Q. Could PacifiCorp avoid investing in new generation by relying on third-party power suppliers?

A. Not entirely. While PacifiCorp does not hold a preference between buying power from third-party suppliers or generating it from owned resources, recent experience has demonstrated that third parties are not always willing or able to economically supply power when and where needed. Certainly compared to the period of the late 1990s, third-party developers have much less ability to finance projects without long-term utility support. Washington State's 2003 Energy Strategy Update[9] characterized the situation as follows:

> "Capital investment tightened considerably in 2001 and 2002. On the federal level, BPA has begun to approach the limits of its federal borrowing authority, a situation that could make it very difficult for the region to upgrade and expand its transmission system. Increased wholesale power costs, decline in demand, and the collapse of the wholesale spot market have threatened both public and private utilities' ability to borrow and caused their credit ratings to suffer. In the wake of the Enron collapse, the financial position of independent power producers is extremely precarious. Liquidity in the wholesale energy markets has also suffered limiting their potential to provide products and services, such as hedging instruments to utilities." (Section 2, page 5)

Power suppliers such as marketers and third-party generation owners now seem much less willing to invest in projects without long-term firm commitments by utilities. Such commitments represent financial obligations that burden a utility's financial structure in ways similar to increased debt.

[9] CTED, 2003 Biennial Energy Report, Energy Strategy Update: Responding to the New Electricity Landscape, February 2003.

Q. Is generation the only area requiring substantial new investment by the Company?

A. No, the Company is making substantial investments in its power transmission and distribution network as well. Reliability requires both adequate generating capability and adequate ability to deliver the power to consumers. The region's, indeed the nation's, energy infrastructure requires improvement. In a recent report to Congress,[10] the Government Accountability Office (GAO) said,

> "[O]ur energy supplies have … witnessed problems, most notably in 2003 when the largest blackout in U.S. history left as many as 50 million people in the dark. Further, there have been indications that our energy infrastructure has not kept up with changes in our demand for energy as illustrated by … the electricity sector's transmission constraints periodically limiting the flow of electricity in parts of the country." (page 2)

Earlier, I quoted CTED regarding approaching limits on BPA's ability to finance new transmission. The broad trend that concerns the GAO applies to PacifiCorp's system as well. PacifiCorp's IRP identifies certain transmission investments related to growth and expansion of the system. These total $462 million over the next ten years.[11] Far larger in total are the many smaller investments not reflected in the IRP. Exhibit No.__(DNF-3) shows excerpts from PacifiCorp's most recent Form 10-K. Table 1 shows that PacifiCorp spends in excess of $350 million per year of capital on its network.

---

[10] "Meeting Energy Demand in the 21st Century: Testimony Before the Subcommittee on Energy and Resources, Committee on Government Reform, House of Representatives," March 16, 2005.

[11] IRP Technical Appendix, page 71.

Q. In total, how much capital spending does PacifiCorp expect in the next several years?

A. Exhibit No.__(DNF-3) shows that the Company's capital expenditure program is increasing and will exceed $1 billion per year by FY 2006.[12]

Q. Is this more than the funds generated by the Company's operations?

A. Yes. Exhibit No.__(DNF-3) Table 2 shows that PacifiCorp was required to raise over $1.3 billion from new equity and long term debt in the fiscal years 2002-2004. Even more funds will be needed in the future, as indicated in the Direct Testimony of Bruce Williams.

Q. Should the cost of this financing be of concern to the Commission?

A. Yes. Interest rates are rising. At the macroeconomic level, trends in interest rates are depicted in the following chart:[13]

[12] The current fiscal year. PacifiCorp's fiscal year 2006 goes from April 2005 through March 2006.

After falling for three years, the bellwether Federal Funds interest rate rose for most of 2004 and continues to rise in 2005. The Direct Testimony of Samuel Hadaway shows that interest rates for corporate bonds are projected to increase from about 5.3 percent to 6.2 percent by the second quarter of 2006. PacifiCorp must expect to pay a higher return to meet future new capital requirements than it has paid in the most recent past.

Q. Does the amount that PacifiCorp must pay for funds depend on the strength of PacifiCorp's financial statements?

A. Yes. A key danger, one that would affect PacifiCorp's customers significantly, is the possibility that PacifiCorp's debt could be downgraded. The relationship between PacifiCorp's financial condition and its bond rating is discussed in the Direct Testimony of Bruce Williams.

Q. Have changes in accounting rules affected PacifiCorp's financial statements?

A. Yes. Accounting rules are actively changing, affecting all companies. The Sarbanes-Oxley Act of 2002 and other rule changes have increased a wide range of requirements. Two accounting developments related to power procurement are worth particular mention.

The first development is known as EITF 01-08. The Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (FASB) has issued an accounting determination related to "off balance sheet financing." Under EITF 01-08, PacifiCorp is required to review each new resource contract (such as purchased power contracts) to determine whether or not they contain a

[13]Federal Reserve Bank of St. Louis,

lease. If they do, an evaluation must be performed using specific accounting standards to determine if the lease is capital or operating. If it is designated to be a capital lease, PacifiCorp would be required to record the value of the asset as debt directly on its balance sheet. This new source of direct debt would require PacifiCorp to add equity to the business in order to maintain its debt/equity ratio. The cost of this equity can increase the effective cost of the resource contract.

Second, accounting rules now require that a utility's earnings reflect changes in the overall value of market contracts. This can magnify the earnings impact of volatile market prices since earnings are affected not just by changes in today's costs but also by changes in price projections for the future.

Q. Suppose that a particular contractual resource did not meet the requirements of EITF 01-08 so that debt was not added directly to PacifiCorp's balance sheet. Could the contract still affect PacifiCorp's credit rating?

A. Yes. Major credit rating agencies and other members of the financial community now view contractual resources as being like debt and will impute or infer debt on the purchaser's financial statements. These adjustments will then be used for ratio calculations and ratings purposes. Bruce Williams and Christy Omohundro discuss this issue further. As in the case of debt being added directly to PacifiCorp's balance sheet, equity must be added in order to offset the effects of this inferred debt. PacifiCorp and other utilities need to take the cost of this added

---

http://research.stlouisfed.org/fred2/series/FEDFUNDS/118 equity into account when considering new power supply alternatives. Regulatory mechanisms can reduce this cost, however, as I describe later in my testimony.

Ratemaking Principles

Q. You have discussed a long list of big industry challenges. What ratemaking principles should the Commission apply in addressing them?

A. The Commission should apply traditional ratemaking principles in ways appropriate to today's situation. James C. Bonbright, who wrote the classic exposition of ratemaking principles,[14] discusses four primary functions of public utility rates. These are:

1. "The Production-Motivation or Capital-Attraction Function"

Regarding the meaning and significance of this function, it seems clearest to quote Bonbright directly:

> "One of the most obvious functions of prices in general is that of motivating and enabling people to participate in the production and distribution of commodities… This is also one of the most prominent and most widely recognized functions of public utility rates. Public utility companies are permitted to impose charges for their services largely in order to induce and enable them to supply these services and to make provision for their continuation and for their required expansion. … In public utility cases in which the general *level* of rates (as distinct from the rate structure) is at issue, the capital-attraction standard of reasonable rates tends to be accepted by commissions as the primary basis for their decisions." (Pages 92-3. Emphasis in original.)

Bonbright also notes:

> "In one important respect, the capital-attraction role of utility rates differs from the similar role played by unregulated, competitive prices. A private,

[14] Bonbright, Danielsen and Kamerschen, Principles of Public Utility Rates, Second Edition 1988, Public Utilities Reports, Inc. The first edition of this book was published in 1961.

> nonutility firm is under no legal obligation to expand output beyond the point that it deems desirable on grounds of profit maximization. But most utilities are under a legal duty to supply adequate service within their franchise territories. Hence, they lack the freedom enjoyed by private businesses to base their expansion program on an estimate of profitability." (Page 95)

<u>2. "The Efficiency Incentive Function"</u>

Here Bonbright refers to the function of prices to "impel rival producers to strive to reduce their own production costs…" (page 95.) Bonbright observes that the "incentive-encouragement features of orthodox rate regulation are extremely crude, and one may suggest that they are very ineffective in comparison with the stimulation of direct and active competition. Whether or not the situation lends itself to material improvement [by relating rates of return to estimates of efficiency] is a controversial question…" (page 96)

<u>3. "The Demand-Control or Consumer-Rationing Function"</u>

This refers to the function of price to signal to consumers the cost of a service. In response, consumers may reduce or expand their consumption. "[P]ublic utility rates are designed to avoid the necessity for overt rationing by making the consumers, in effect, ration themselves." (page 97) Utility rates restrict "the demand for service to those demands for which consumers are ready to cover costs of rendition…" (page 100)

<u>4. "The Compensatory Income-Transfer Function"</u>

This function deals with divergences of price from cost for the purposes of transferring income. Low-income rates, for instance, would be justified under this function. "Very wisely, in our opinion, the literature on utility and rate theory generally supports" a standard under which prices merely offset costs. (page 103)

There are clearly tensions among these functions. Issues presented in this filing will highlight the tension between the Capital-Attraction Function and the Efficiency Incentive Function. Regulatory mechanisms that reduce risk to the Company provide a better environment for the attraction of capital but they may also seem to reduce management's incentives for efficiency. I would make three general observations regarding this tension:

- The present and likely future industry environment makes capital attraction much more important than it has been. Regulation should respond to this and favor capital attraction more than it has in the past.
- The present and likely future industry environment places more risk on the Company than it has faced in the past. For the Company to remain in the same risk position, new regulatory mechanisms to manage risk are needed.
- Placing risk on the Company is not an efficiency incentive if the Company can do nothing about the risk. Power markets are outside of the Company's control. While the Company does take actions to control its power costs and will continue to have incentives to do so, too much uncontrollable risk can lead to inefficient responses. It could cause the Company to focus on risk control at the expense of building for the long term. More risk could be counterproductive to the Efficiency Incentive Function.

Q. How should the Commission strike a balance among the ratemaking principles?

A. The Commission should authorize a rate of return that will allow the Company to readily attract the capital it needs and provide a real opportunity to earn that rate of return.

The Company is requesting that the Commission authorize a return of 11.125 percent on its equity capital. This request is described in the Direct Testimony of Samuel Hadaway. It is in line with returns recently authorized for other similar utilities around the country. This return is often referred to as the "cost of equity." Even though the cost of equity is not treated as a cost in the Company's accounting records, it is truly a cost in that it is the opportunity cost to investors, the amount they could earn by investing in other utilities. As a real cost, the Company should have a real opportunity to recover it. It is a given in regulation that a utility should have an "opportunity to earn its authorized rate of return." The "opportunity" must not be only a mathematical possibility. In the Company's view, the "opportunity" to earn its authorized rate of return should mean that if the Company behaves prudently, it can *expect* to earn its authorized rate of return. As I have discussed earlier in this testimony, the Company will require substantial new equity and debt in the coming years in order to provide reliable service. Our proposed regulatory approach will help ensure that the needed funds are available and the needed investments can be made.

Q. Is this approach consistent with Washington State energy policy?

A. Yes. It is not only consistent but I believe it is required. The 2003 Energy Strategy adopts as a Guiding Principle, "Foster a predictable and stable investment climate to facilitate adequate and efficient access to capital markets for …Washington's public and private energy industry."[15] The report notes:

> "Electricity system investments, be they in generation, distribution, transmission, or energy efficiency, are by their very nature capital intensive. Consequently, access to capital markets is critical to the future viability of the state's electricity system."

Proposed Regulatory Mechanisms – PCAM, Decoupling and Revised Protocol

Q. What regulatory mechanisms does the Company propose in this filing?

A. PacifiCorp proposes three key regulatory mechanisms to support continued reliable operations. PacifiCorp proposes:

- A new Power Cost Adjustment Mechanism (PCAM) to deal with volatility in power costs;
- Development and adoption of a decoupling mechanism to support implementation of energy conservation programs; and
- The Revised Protocol method of allocating PacifiCorp's costs among its state jurisdictions.

The first two of these would implement new mechanisms while the third resolves a long-standing issue of standard ratemaking.

Q. Please summarize the PCAM that PacifiCorp proposes in this case.

A. The proposed PCAM is very similar to Avista Corporation's Energy Recovery Mechanism (ERM). It would establish a bookkeeping account into which would be recorded ninety percent of the difference between (1) the level of power costs authorized by the Commission when setting rates in this proceeding and (2) the actual level of power costs. The account balance would be adjusted to reflect changes in recovery of power costs through base rates. Amounts entered into the account could be either positive or negative. PacifiCorp would file to recover from or refund to customers the balance of the account when the balance exceeds a specified threshold. The specifics of the PCAM would depend on the particular form of decoupling agreed upon by the parties as I describe later in my testimony. Christy Omohundro and Mark Widmer discuss the PCAM in greater detail.

Q. Has PacifiCorp had a PCAM in Washington before?

A. No. As I described earlier in my testimony, the combined effects of greater power cost volatility and higher levels of investment make a PCAM necessary at this time. PacifiCorp has filed or intends to file PCAMs in each of its jurisdictions.

Q. How does the PCAM support the ratemaking principles that you have discussed?

A. The PCAM would improve the Company's ability to earn its authorized rate of return. At present, unanticipated changes in power costs are not generally recovered in rates at all since rates are based upon expected or normal power costs and are not "trued up" to actual costs. The PCAM would do this – true up rates to actual power costs, leaving a reduced portion of the volatility with shareholders. The PCAM would strengthen the degree to which PacifiCorp's rates support the Capital Attraction Function, as Christy Omohundro describes in her Direct

[15] 2003 Biennial Energy Report, page 2-5.

Testimony, and lower the amount of debt inferred for contractual resources by credit rating agencies and reducing the cost of new capital. The PCAM will not have a material negative effect on the Efficiency Incentive Function because:

- Power cost volatility is largely outside the Company's control;
- Stronger regulatory sanctions related to prudence are available to the Commission which are more directly focused on Company decisions and give the Company incentives to control costs; and
- The Company will still bear a meaningful share of power cost risk.

The PCAM has no effect on the Income-Transfer Function.

The PCAM supports the Demand-Control Function of rates far more strongly than existing regulation. Today, if power prices rose unexpectedly consumers might never know it because unexpected power costs are generally not reflected in rates. Consumers are in a position to influence power costs too, by controlling the amount they use. Today consumers have no incentive to reduce the amount they use when costs rise unexpectedly. The PCAM would improve this situation by providing price signals that link the Company's actual costs to the prices paid by consumers.

Q. What is "decoupling"?

A. "Decoupling" refers to regulatory mechanisms that reduce or remove the link between a utility's revenue and its sales as a means of reducing or eliminating any financial disincentives to DSM investment. Generally a decoupling mechanism would specify a baseline revenue requirement formula, for instance related to the number of the utility's customers. Differences between actual and baseline revenues would be recorded into a balancing account to be later refunded to or recovered from customers. If a utility implements a large, effective energy conservation program, sales of electricity may fall. The utility would be penalized for successful conservation efforts without decoupling.

Q. Why is PacifiCorp proposing the development of a decoupling mechanism in this proceeding?

A. Decoupling was discussed in Docket No. UE-032065. In that proceeding, the Commission ordered:

> "PacifiCorp may propose a true-up mechanism, or some other approach to reducing or eliminating any financial disincentives to DSM investment. This could be in connection with a general rate proceeding such as the Company suggests will be filed sometime in 2005…"(Order No. 06,¶ 69)

In the spirit of that finding, the Company proposes that a decoupling mechanism be developed in this proceeding.

Apart from addressing the issue identified in the Commission's order, a decoupling mechanism is appropriate for other reasons as well. Decoupling supports the Efficiency Incentive Function of rates by removing a disincentive for the utility to invest in conservation programs that are cost-efficient alternatives to new generation. Decoupling also supports the Capital Attraction Function by stabilizing revenues from year to year.

Decoupling is particularly appropriate when combined with a PCAM. A utility's non-power costs tend to be more stable than its power costs. Today, for instance, when a cold winter increases electricity usage, customers pay more – not just for the power cost portion of their rate – but for all of it. While the utility's power costs increase in such a situation, its non-power costs do not change much.

Thus, the increased costs borne by customers may exceed the actual cost increases incurred by the utility. The effect of including a decoupling mechanism with a PCAM is to stabilize the excess of revenues over power costs. The combination of decoupling and a PCAM will result in prices paid by customers that more closely reflect actual costs compared to standard ratemaking.

Q. Why hasn't PacifiCorp proposed a specific decoupling mechanism in its direct case?

A. The Commission's order suggests that a decoupling mechanism should be developed in consultation with other parties. A cooperative approach is appropriate since a variety of specific mechanisms can be used to implement decoupling and parties appear to have different views regarding those mechanisms.

Q. Has PacifiCorp considered any specific methods of decoupling?

A. Over the years, PacifiCorp has reviewed decoupling mechanisms approved by commissions in the states we serve. From this experience, we conclude that the decoupling mechanism needs to fit the utility's situation and previous precedent in that state. The California PUC, for instance, has generally used a similar approach for many years. Tariffs of large utilities separately state charges for power costs and for other costs. Base rates (which exclude power costs) of these utilities are reviewed on a fixed three-year rate case cycle. The PUC approves formulas for increasing authorized base revenue requirements between rate cases. Decoupling is implemented by recording in a bookkeeping account the monthly difference between base revenues and authorized base revenue requirements. The balance of the account is refunded to or recovered from customers the following year. The power cost portion of rates in California is adjusted in a separate annual process. The California PUC requires utilities to track their actual power costs in a separate account and to fully pass them through to customers. These two mechanisms together allow utilities to recover no more and no less than their authorized base revenue requirements.

Q. Could adoption of a decoupling mechanism affect other aspects of the Company's filed case?

A. Yes it could, although parties may be able to develop a decoupling mechanism that minimizes the impact. For instance, adoption of a full decoupling mechanism like California's would be inconsistent with the PCAM we are proposing in this proceeding, in two respects. First, the decoupling mechanism would duplicate a base rate recovery adjustment which is already included in the PCAM we are proposing. Second, the 90/10 sharing mechanism proposed in the PCAM is inconsistent with "100 percent" decoupling. With an increase in sales, PacifiCorp would be able to recover only 90 percent of the additional power costs and would be unable to retain any of the added sales revenue. Some form of partial decoupling might avoid this inconsistency. In discussions regarding decoupling, parties will need to consider such effects.

Q. How does PacifiCorp propose to resolve the decoupling issue in this proceeding?

A. PacifiCorp proposes that discussions of the decoupling issue occur concurrently with the initial phases of this case. All parties to this proceeding will be welcome to participate in these discussions. PacifiCorp hopes and expects that discussions will lead to a proposal acceptable to the Company and at least some of the other parties in the case. If so, we propose to file testimony jointly with the agreeing parties setting forth specifics of the proposal and the basis for recommending it to the Commission. PacifiCorp suggests as a goal that the proposal be submitted at the time that PacifiCorp files its rebuttal testimony in this proceeding. Implementing a decoupling proposal does not typically require the filing of new tariffs because only accounting procedures need to be established at the outset, which will lead to rate changes after the mechanism is in operation.

Q. Please briefly describe the Revised Protocol method of allocating PacifiCorp's costs among state jurisdictions.

A. Where possible, the Revised Protocol assigns costs to the state that is directly responsible for them. Costs of distribution facilities and certain state-mandated programs are assigned in this way. The majority of PacifiCorp's costs are not, however, directly caused by any particular state. In those cases, costs are allocated based on a state's share of system energy, peak demand, and other factors. The particular allocation factors are different for different kinds of cost. For instance, the Revised Protocol allocates the benefits of the Company's low-cost hydroelectric system more heavily to Washington and other former Pacific Power states than to former Utah Power states.[16] As another example, the Revised Protocol allocates the costs of seasonal resources to states on a weighted

[16] The distinction between Pacific Power and Utah Power states refers to the merger, in 1989, between Pacific Power & Light and Utah Power & Light. Former

basis that considers monthly state loads and monthly resource operation. In this manner, the costs of summer-peaking combustion turbines are allocated to summer-peaking states. The Revised Protocol calls for the creation of a Standing Committee composed of representatives from each state who will recommend solutions to allocation issues that may arise over time. The Direct Testimony of David Taylor contains full details of the Revised Protocol.

Q. How was the Revised Protocol developed?

A. The Revised Protocol is the result of extensive discussions lasting several years and involving parties from the various states. This process was called the Multi-State Process, or MSP.

Q. Why did participants undertake this large effort?

A. Previous agreements on allocation methods had broken down. States had adopted differing allocation methods with the result that PacifiCorp was unable to recover all of its prudently incurred costs. The size of the allocation "hole" was estimated to be $45 million per year. In addition, there was little consensus among the states regarding how PacifiCorp should meet requirements for new resources or who should pay for them. MSP was the first major initiative by which the Company and its regulators worked together to address major regulatory issues related to the need to acquire new resources.

Q. What principles formed the basis of a solution?

A. Participants seemed to recognize that a solution to MSP issues should:

a) promote economic efficiency;

Pacific Power states are California, Oregon, Washington and Wyoming. Former Utah

b) be equitable to PacifiCorp's customers and shareholders;

c) allow individual states to pursue policy initiatives without burdening customers in other states;

d) permit continued effective regulatory oversight; and

e) not impede the provision of safe, adequate and reliable service by the Company.

It seemed to be generally understood and agreed that the MSP should not result in a disproportionate cost shift among states.

Q. Have any other states adopted the Revised Protocol allocation method?

A. Yes, the Revised Protocol has been adopted in the states of Idaho, Oregon, Utah and Wyoming, which account for approximately 90 percent of PacifiCorp's retail revenues. Only California, where it has not been filed, and Washington have yet to adopt the Revised Protocol.

Q. Has PacifiCorp previously presented the Revised Protocol in Washington for consideration by the Commission?

A. Yes, in Docket No. UE-032065. That proceeding did not result in an agreement among parties regarding the appropriate allocation method. The Commission ordered PacifiCorp to initiate discussions with Washington parties after the Oregon and Utah commissions had issued orders on the proposed allocation method. The Commission also ordered PacifiCorp to present a status report to the Commission and, by October 31, 2005, to file a proposal to "resolve inter-jurisdictional cost allocation in Washington." Parties discussed the issue in a

---

Power states include Idaho and Utah.

series of meetings and conference calls. These discussions were a good-faith effort to develop a mutually acceptable allocation method for Washington but did not result in agreement. PacifiCorp issued a status report on March 30, 2005, which is included as Exhibit No. ___(DNF-4). The present filing includes PacifiCorp's proposal to resolve the issue.

Q. Why should the Commission adopt the Revised Protocol in this proceeding?

A. The Revised Protocol improves PacifiCorp's ability to provide safe, adequate, and reliable service, while at the same time reducing the share of PacifiCorp's costs allocated to Washington customers. The Revised Protocol benefits Washington customers. It is equitable for customers in all states and for shareholders. It promotes economic efficiency because it permits and encourages continued operation of PacifiCorp's system as an integrated whole. It is responsive to the policy needs of individual states. Finally, the Revised Protocol is workable and thus permits continued effective regulatory oversight.

Clearly, all of PacifiCorp's commissions together must set rates using allocation methods that "add to 100 percent" in order for the Company to have a reasonable opportunity to earn its authorized rate of return. Allocation methods that, in practice, do not allow the Company to recover all of its prudently incurred costs are inconsistent with the Capital-Attraction Function of rates.

Q. Does the Revised Protocol allocation method provide quantifiable benefits to PacifiCorp's Washington customers in this case?

A. Yes. The use of the Revised Protocol in this case reduces Washington's revenue requirement by $2.7 million, or 1.0 percent, as compared to the revenue requirement resulting from the allocation method that PacifiCorp has previously used in Washington. This is largely due to the special treatment of low-cost hydroelectric resources and the method of allocating the costs of qualifying facilities. Mr. Taylor provides additional detailed discussion in his testimony related to the elements of the Revised Protocol and their impact in this filing.

Overview of Cost Pressures

Q. Describe the rate increase that PacifiCorp seeks in this case.

A. Average rates would increase 17.9 percent from rates in effect today. Adjusted for inflation, PacifiCorp's average Washington price would return to the levels of 1995. The Direct Testimony of William Griffith shows that even with this increase, Pacific Power's average rate will remain low in a low-cost state.

Q. Without an increase, what rate of return is PacifiCorp presently earning?

A. Present rates produce a return on equity of 3.5 percent, as the Direct Testimony of Paul Wrigley shows. This level of earnings will not readily attract the capital needed for the Company's future operations. An 11.125 percent return on equity is supported by Dr. Hadaway's testimony in this proceeding. Dr. Hadaway's testimony indicates a range of appropriate levels of return on equity from 10.7 to 11.8 percent. The Company is requesting that the Commission approve a return on equity near the center of that range.

Q. Are there key factors other than power costs that contribute to the Company's increasing cost structure?

A. Yes. As previously discussed in PacifiCorp's 2003 general rate case (Docket No. UE-032065), the Company continues to experience cost pressures related to pensions, medical costs, and other employee costs. The Company is proposing to recover $53 million (on a total Company basis) in annualized test period pension costs in this case. Mr. Rosborough will describe these costs in detail and explain what the Company is doing to control these costs.

Q. What is driving the significant increase in the Company's Net Power Costs?

A. I have already discussed a number of general factors. The forward markets for electricity and natural gas currently reflect significantly higher prices in the future than during recent history. Rising coal costs are also a factor. Higher retail load requirements have also contributed to higher total Company Net Power Costs. A number of additional factors also impact Net Power Costs, including new purchases and the expiration of certain power purchase contracts. Mr. Widmer's testimony describes the basis for the increase in Net Power Costs in more detail.

Q. Given the impact of Net Power Costs on this rate application, are there investments that the Company should or could be making to moderate their impact?

A. Yes. Earlier in my testimony, I referred to the resources that the Company is presently acquiring and the future resources called for in the IRP. These resources will reduce the exposure of our customers to rising and volatile commodity markets, and to acquire them, the Company needs to be financially healthy.

Q. Have past Company actions helped to keep prices low during the recent turbulence in the energy industry?

A. Yes. Over the years, the Company has taken several innovative actions that keep our prices low today. For example, the Pacific Power & Light Company system combined low cost Wyoming coal-fired generation with flexible hydro resources in the Northwest. Adding the Utah Power & Light Company generation and transmission system provided even more flexibility and additional markets to dispose of excess energy and to import energy when needed. The Company has also enjoyed significant benefits over the years from the low cost Mid-Columbia long-term purchase agreements. PacifiCorp's diverse portfolio of renewable, hydropower, and thermal resources has helped insulate customers in the past from extreme market conditions and positioned the Company as one of the lowest cost utilities in the nation.

More recently, the decision to acquire several new generation resources in Utah helped to avoid millions of dollars in purchases and transmission costs, while providing dispatch flexibility and other ancillary benefits. The Company's increasing commitment to renewable resources – shown in acquiring the output of the Invenergy and Eurus wind projects – increases fuel diversity and may lead to less volatile energy costs over time. Prudent investments and power purchase agreements such as these require a healthy balance sheet and assurance of cost recovery. Such investments were possible only because the Company had the financial strength to invest or to enter into long-term contracts.

Q. Can you provide any additional examples of recent investments made with the goal of retaining PacifiCorp's low-cost service?

A. Yes. PacifiCorp recently invested in converting the Bridger mine from a surface operation to an underground mine. This investment will allow the Company to continue to supply its power plants from mines that it controls. The Bridger plant is a key resource for serving the entire system, and at very low cost. By making the investment to take the mine from a surface operation to an underground mine, the Company will be able to continue to control a low-cost source of fuel, close to the plant, utilizing many existing assets.

Q. Please describe the Currant Creek resource and how it is reflected in this case.

A. Currant Creek is a gas-fired combustion turbine project located south of Salt Lake City. Phase One of Currant Creek results in a capacity of 280 megawatts and is planned to be operational by the summer of 2005. Phase Two of the project, planned for completion by early 2006, converts the plant to a combined-cycle combustion turbine with a total capacity of 525 megawatts. Costs related to both phases are included in this filing because both phases will be operational during the rate-effective period.

Q. In addition to specific investments, how does the Company control costs?

A. PacifiCorp has developed extensive and rigorous processes for controlling costs. Capital expenditures are controlled using layered processes that extend from planning for the Company's capital needs, to deciding to implement specific projects, through project completion, and after. Expenses are controlled by budgeting and planning processes that keep pressure on managers to absorb increasing costs through efficiency initiatives.

Q. Describe the process that the Company uses to control capital costs.

A. Control of capital spending starts with the budgeting and planning processes. These identify future situations in which the Company's total capital needs may stress its financial resources and allocate capital investment to business units. The budget process includes a rigorous review of possible major capital projects and the level of spending on more routine capital items.

Regardless of budget authorization, major capital projects must be individually approved by senior management before expenditures are made. Senior management also oversees ongoing projects and conducts post-investment reviews to audit that projects are completed on budget and on time and to assess the benefits produced by the projects. As a member of senior management, I participate in the review and approval of capital projects. The review process is sufficiently rigorous to ensure, to the fullest extent possible, that PacifiCorp undertakes the right projects and executes them well.

Q. Has the control process 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 number one with 86.4 percent of customers with at least one megawatt of demand "very satisfied" with the level of service provided to them. 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. PacifiCorp's service quality commitments were recently extended.

Q. What capital structure does the Company propose to use for setting rates in this proceeding?

A. This filing is based on a capital structure comprising 49.4 percent long-term debt, 1.10 percent preferred stock, and 49.5 percent common equity. In order to achieve this capital structure, PacifiCorp's parent company, PacifiCorp Holdings, Inc. (PHI), will make four equity infusions totaling $500 million by the end of March 2006. These equity infusions are critical to enable the Company to maintain credit ratios that support the continuance of our current 'A-' credit rating during its current resource acquisition cycle.

Introduction of Witnesses

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

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 DCF (Discounted Cash Flow) 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 11.125 percent.

Bruce N. Williams, Treasurer, will present a financing overview of the Company and explain the need for the Company to increase the equity component of its capital structure, in order to maintain credit ratings that support an "A-" rating. He will present PacifiCorp's capital structure of 49.4 percent long-term debt, 1.10 percent preferred stock, and 49.5 percent common equity. He will also testify concerning the Company's cost of debt and preferred stock. Mr. Williams will show that the Company's embedded cost of long-term debt is 6.427 percent and the embedded cost of preferred stock is 6.59 percent.

David L. Taylor, Principal Regulatory Consultant, sponsors the Company's testimony describing in detail the Revised Protocol method of allocation. Mr. Taylor also presents testimony on class cost of service and functional revenue requirement.

Christy A. Omohundro, Managing Director , Regulation will present the Power Cost Adjustment Mechanism proposed by the Company in this case, and the manner in which the Company proposes to implement this mechanism.

Mark T. Widmer, Director, Net Power Costs, will describe the operation of the GRID model, including the new VISTA model for hydro normalization, and the calculation of net power costs. Mr. Widmer will also identify the major drivers that are putting upward pressure on power costs and describe the volatility of power costs that leads the Company to propose a PCAM.

Gregory N. Duvall, Managing Director, Planning and Major Projects, addresses inter-jurisdictional cost allocation, including the allocation of power cost variances under the Company's proposed PCAM. He also shows that the

Company's resource acquisitions of Craig, Hayden, Cholla 4, Foote Creek, West Valley, Gadsby and Currant Creek generating units are prudent for purposes of Washington rates.

Mark R. Tallman, Managing Director of Commercial and Trading, will describe the Company's recent supply-side resource portfolio acquisitions. These include, among others, the Currant Creek project, the acquisition of the output from the Eurus Oregon Wind Power project, and the decision to continue the West Valley lease.

Paul M. Wrigley, Regulation Manager**,** will present the Company's overall revenue requirement based on the test period (twelve months ending September 30, 2004), and known and measurable adjustments through the rate-effective period. Mr. Wrigley will present the normalizing adjustments to actual test period results related to revenue, operation and maintenance expense, net power costs, depreciation and amortization, taxes and rate base.

Daniel J. Rosborough, Director of Employee Benefits, will testify to the Company's increased pension and employee benefit costs. Mr. Rosborough will also address the actions the Company is taking to control these rising costs.

William R. Griffith, Director of Pricing and Cost of Service, will present testimony on three primary areas: 1) description of the Company's pricing objectives, 2) the Company's proposed rate spread, and 3) the Company's proposed changes in price design for the affected rate schedules.

Q. Does this conclude your testimony?

A. Yes.