BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF PACIFICORP DBA UTAH POWER & LIGHT COMPANY FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES	) CASE NO. PAC-E-05-1)) Direct Testimony of David L. Taylor))

PACIFICORP

CASE NO. PAC-E-05-1

January 2005

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

A. My name is David L. Taylor. My business address is 825 N. E. Multnomah, Suite 800, Portland, Oregon, where I am employed as a Principal Regulatory Consultant.

Qualifications

Q. Please briefly describe your education and business experience.

A. I received a BS in Accounting from Weber State College in 1979 and an MBA from Brigham Young University in 1986. I have been employed by PacifiCorp since the merger with Utah Power in 1989. Prior to the merger I was employed by Utah Power, beginning in 1979. At the Company I have worked in the Accounting, Budgeting, and Pricing and Regulatory areas. From 1987 to the present I have held several supervision and management positions in Pricing and Regulation.

Q. Have you appeared as a witness in previous regulatory proceedings?

A. Yes. I have testified on numerous occasions in California, Idaho, Montana, Oregon, Utah, Washington and Wyoming.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. In my testimony I will describe how the MSP Revised Protocol allocation methodology and the stipulated Rate Mitigation Mechanism filed in Case No. PAC-E-02-03 affect the Company filing in this case. Additionally I will describe the jurisdictional allocation changes between the Modified Accord Allocation Methodology previously adopted by the Idaho Commission and the Revised Protocol allocation methodology and detail the impacts of those allocation changes on the

Idaho revenue requirement. Finally I will present PacifiCorp's functionalized Class Cost of Service Study based on twelve month test period ending March 31, 2004 (FY04). I will also describe any differences between this cost study and the studies filed previously with the Idaho Commission.

Rate Mitigation

Q. Please describe the Rate Mitigation Cap.

A. On November 4, 2004, PacifiCorp, IPUC Staff, AARP, and Monsanto filed a stipulation recommending approval of the MSP Revised Protocol. A part of that stipulation is a Rate Mitigation Cap that limits the early year impacts of the moving to the Revised Protocol. Paragraph six of the Stipulation states:

> 6. Support of the Revised Protocol by the undersigned is contingent upon subsequent ratification by the Idaho Commission of this Stipulation incorporating use of the Revised Protocol and the following Rate Mitigation Mechanism that is intended to apply to calculations of the Company's Idaho revenue requirement for filings made through March 31, 2009:
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> a. For all Idaho general rate proceedings initiated after the effective date of this Stipulation and the Revised Protocol, and until March 31, 2009, the Company's Idaho revenue requirement to be used for purposes of setting rates for Idaho customers will be the lesser of: (i) the Company's Idaho revenue requirement calculated under the Rolled-In Allocation Method multiplied by 101.67 percent, or (ii) the Company's Idaho revenue requirement resulting from use of the Revised Protocol. As shown on Exhibit B, this Rate Mitigation Measure is designed to implement the Revised Protocol in the Company's next general rate proceeding with no additional incremental impact in subsequent cases above 101.67 percent, relative to the Rolled-In Method through March 2009.

Q. What is the impact of the Rate Mitigation Cap in this case?

A. As shown in Exhibit No. 18, the Idaho FY04 revenue requirement is capped at $178.5 million, or 101.67 percent of the Idaho Revenue Requirement as calculated under the Rolled-in Allocation Method. The Rate Mitigation Cap limits the

PacifiCorp requested rate increase to $15.1 million, which is $1.8 million less than the non-mitigated rate increase calculated using the Revised Protocol as described in Mr. Weston's testimony.

Impacts of MSP Revised Protocol

Q. Have you prepared an exhibit that shows the revenue requirement impacts of adopting the Revised Protocol Allocation Methodology as compared to the Modified Accord Allocation Methodology?

A. Yes. Exhibit No. 19 compares the Idaho revenue requirement, as calculated by Mr. Weston, using the previously adopted Modified Accord allocation method with the Idaho revenue requirement using the MSP Revised Protocol allocation method. Page one of Exhibit No. 19 shows the impact of each change in allocation methodology.

Using the Modified Accord allocation methodology the target Idaho revenue requirement in this case, as shown on line 1, would have been $179.5 million.

The MSP Revised Protocol, which begins with a fully rolled-in allocation methodology, eliminates the divisional assignment of pre-merger generation and transmission plant investments and the fuel adjustment hydro endowment. As shown on line 2, moving from the Modified Accord to the Rolled-in jurisdictional allocation reduces the Idaho revenue requirement by $4.0 million. Offsetting this amount are the $4.5 million net cost to Idaho associated with the new Owned-Hydro Embedded Cost Differential Adjustment shown on line 3 and the $2.1 million net cost associated with the Mid-Columbia Contracts Embedded Cost Differential Adjustment shown on line 4. Line 5 shows $2.3 million net benefit to Idaho associated with the Existing Qualified Facility (QF) Contracts Embedded Cost Differential Adjustment. Finally, line 6 shows the $0.4 million net cost to Idaho as a result of the seasonally weighted allocation of certain resource costs. I will describe each of these items in greater detail later in my testimony.

As shown on line 7, the sum of these allocation changes produces a net increase to the Idaho revenue requirement of $0.7 million. This amount is mitigated by the Rate Mitigation Cap described in Exhibit No. 18. As a result, the Idaho revenue requirement requested by the company in this case is actually $1.1 million lower than the revenue requirement produced by the previously adopted allocation methodology.

Pages two, three and four of Exhibit No. 19 contain the FY04 Idaho results of operations summary using the MSP Revised Protocol, Rolled-In and Modified Accord allocation methodologies, respectively.

Revised Protocol Allocation Procedures

Q. Under the MSP Revised Protocol, how are the bulk of the Generation and Transmission costs classified and allocated?

A. The MSP Revised Protocol is based on a single integrated system, rolled-in allocation methodology. All Resource Fixed Costs, Wholesale Contracts and Short-term Purchases and Sales continue to be classified as 75 percent Demand-Related and 25 percent Energy-Related. All costs associated with Non-Firm Purchases and Sales continue to be classified as 100 percent Energy-Related. Other than the Seasonal Resources, described below, Generation and Transmission demand related costs are allocated using the fully rolled-in, 12 Coincident Peak (CP) method and energy related costs continue to be allocated using annual energy consumption.

Cost Allocation for Seasonal Resources

Q. How are the costs of Seasonal Resources allocated differently than the costs of System Resources?

A. In contrast to the allocation of non-seasonal resources described above, each state's contribution to system peak and energy usage is weighted seasonally in development of the allocation factors for Seasonal Resources. Prior to summing the twelve monthly Coincident Peaks, each monthly CP measurement is weighted by the monthly portion of the total annual energy either generated or delivered by the Seasonal Resource. For example, if 30 percent of the annual megawatt hours generated or delivered by a particular Seasonal Resource occurs in July, the monthly Coincident Peak for July would be weighted by 30 percent in the calculation of the allocation factor. This, in essence, allocates 30 percent of the Demand-Related Cost for that Resource among states based upon their contribution to the July Coincident Peak.

Similar to the weighting of Demand-Related costs, each state's monthly energy usage is weighted by that month's portion of annual energy generation for the particular Resource. The annual fuel costs for that Resource are then allocated using its seasonally weighted energy factor.

Somewhat different procedures are used for simple-cycle combustion turbines, Seasonal Contracts and the costs of Cholla Unit IV. The calculation of the seasonally weighted allocation factors for each of the Seasonal Resources is shown in Exhibit No. 20. Page 1 of this exhibit contains the temperature-normalized monthly energy and monthly contribution to system Coincident Peak for each of the states. Pages 2 through 4 detail the factor calculation for the costs of simple-cycle combustion turbines, Seasonal Contracts and the costs of Cholla Unit IV, respectively.

Q. How are the costs of Simple-Cycle Combustion Turbines (SCCTs) allocated?

A. Both the Demand-Related and Energy-Related Costs are assigned to the individual months of the year on the proportional basis of the SCCT's monthly megawatt hours generated to its annual megawatt hours for the times when the resources are dispatched to meet retail load.

Q. How are the costs of Seasonal Contracts allocated?

A. As with the SCCTs, the costs of Seasonal Contracts are allocated on a weighted monthly basis according to their monthly delivered megawatt hours. Because some of the contracts do not have explicit Demand and Energy components, however, the entire contracts will be classified as 75 percent Demand and 25 percent Energy.

Q. How are the costs of the Cholla plant allocated differently from SCCTs?

A. The Cholla plant is considered a winter Seasonal Resource. Although Cholla Unit IV is operated all year except for times of required maintenance, a substantial portion of the summer output is delivered to Arizona Pubic Service Company ("APS") and an equivalent amount of capacity and energy is returned to PacifiCorp during the winter months.

The costs of the Cholla plant are allocated using a similar monthly weighting methodology as used for SCCTs with an adjustment for the megawatt hours delivered to and received from APS. Both the demand and energy components of plant costs are assigned to months on the basis of monthly megawatt hours dispatched from Cholla plus megawatt hours received from APS, less megawatt hours delivered to

APS. This assigns the majority of the Cholla costs to five winter months, October through February.

Embedded Cost Differential Adjustments

Q. Earlier in you testimony you indicated that there were three Embedded Cost Differential Adjustments. Please explain these adjustments and how they were calculated.

A. The Revised Protocol introduces a new concept of affording states value from their allocated share of Hydro-Electric Resources and Mid-Columbia Contracts through an "embedded cost differential" calculation. Additionally, cost responsibility for the Existing QF Contracts located in each state is more directly assigned to that state through another "embedded cost differential" calculation.

Generally speaking, the costs of Hydro-Electric Resources, the Mid-Columbia Contracts and Existing QF Contracts are first allocated on a system-wide, rolled-in basis. After the system-wide allocation, a separate "embedded cost differential" calculation then compares the total embedded cost of Hydro-Electric Resources, Mid-Columbia Contracts and Qualifying Facilities on a dollar per MWh basis with the total embedded cost of the Company's other Resources (excluding the costs of Hydro-Electric Resources, Mid-Columbia Contracts and Existing QF Contracts). The difference in cost is then multiplied by the normalized output from the Hydro-Electric Resources, Mid-Columbia Contracts and QF Contracts. If the difference is negative (the Hydro-Electric Resources, Mid-Columbia Contracts or QF costs are less expensive than other Resources), it is credited to the states with the hydro endowment, or the state where the QF is located. If the difference is positive (the

Hydro-Electric Resources, Mid-Columbia Contracts or QF costs are more expensive than other Resources), there is a charge to the hydro endowment states, or state where the QF is located.

More specifically, the Owned-Hydro Embedded Cost Differential Adjustment is allocated to former Pacific Power jurisdictions using the DGP factor, the Mid-Columbia Contracts Cost Differential Adjustment is allocated to all states using the Mid-Columbia (MC) factor, and the Existing QF Contracts Cost Differential Adjustment is calculated for each specific state and assigned situs to that state.

The total Company inverse amount for each of these adjustments is allocated to all states using the SG factor. This nets each state's allocated or direct assigned share of each embedded cost differential, as just described, against its share of that same differential that was, in the first instance, allocated on a system-wide basis.

Q. How are the Company's Annual Embedded Costs used in the embedded cost differentials calculated?

A. Exhibit No. 21 details the Annual Embedded Costs calculation for Hydro-Electric Resources, Mid-Columbia Contracts, Existing QF Contracts, and all other Resources. As shown on lines 1 through 13, the Annual Embedded Costs - Hydro-Electric Resources include the identified hydro-related operation and maintenance, depreciation, and amortization expenses plus the identified hydro-related rate base items times the pre-tax authorized (or requested) return on rate base. This amount is divided by the annual hydro MWh, from the GRID run used in the test period net power cost calculation. The resulting Annual Embedded Costs – Hydro-Electric Resources of $18.10 per MWh is $16.70 per MWh less than the Annual Embedded

Cost for all other resources.

The Annual Costs, MWh, and corresponding cost per MWh are shown for Mid-Columbia Contracts on lines 14 and Existing QF Contracts on lines 15 through 22.

The Annual Embedded Costs - All Other are shown on lines 23 through 55. This calculation is similar to the costs for Hydro-Electric Resources described above and results in Annual Embedded Costs – All Other of $34.81 per MWh. This is the cost to which Annual Embedded Costs - Hydro-Electric, Annual Mid-Columbia Contract Costs, and Annual Existing QF Costs are compared.

Q. Are the Idaho special contracts included in the results of operations?

A. Yes. Consistent with the Revised Protocol, the loads and revenues associated with service to Idaho special contract customers are included as part of Idaho's jurisdictional allocation and included in the revenue requirement.

Cost of Service

Q. Please identify Exhibit No. 22 and explain what it shows.

A. Exhibit No. 22 is the summary table from PacifiCorp's Fiscal Year 2004 Class Cost of Service Study for the State of Idaho. It is based on PacifiCorp's annual results of operations for the State of Idaho presented in the testimony of Mr. Weston. It summarizes, both by customer group and by function, the results of the FY04 cost study. Page 1 presents results at the Company's FY04 Rate of Return assuming current rate levels. Page 2 shows the results using the return provided by the $15.1 million requested price increase.

Q. Please identify Exhibit No. 23 and explain what it shows.

A. Exhibit No. 23 shows the cost of service results in more detail by class and by function. Page 1 summarizes the total cost of service summary by class and pages 2 through 6 contain a summary by class for each major function.

Changes in Cost of Service Study

Q. Are there any differences between this cost study and the studies filed previously with the Idaho Commission?

A. Yes. The methodology used in this study for the allocation of generation and transmission costs is consistent with the Revised Protocol allocation methodology I discussed in earlier in my testimony.

Q. How has the Revised Protocol methodology impacted the Cost of Service Study?

A. The Revised Protocol methodology identifies four categories of Resources: Seasonal Resources, Regional Resources, State Resources, and System Resources. Additionally, the Revised Protocol uses three Embedded Cost Differential Adjustments. Only the seasonally weighted allocation of the Seasonal Resources and the Embedded Cost Differential Adjustments have an impact on the class COS study.

Q. Is the classification of seasonal resources different from that of other resources?

A. No. All resources are classified as 75 percent Demand and 25 percent Energy.

Q. How are seasonal resources allocated differently from other resources?

A. The allocation methodology for seasonal resources was described in the revenue requirement portion of my testimony. The seasonal weightings for class allocations work the same way as I described for states in the revenue requirement portion of my testimony.

Q. How are the Embedded Cost Differential Adjustments allocated to the customer classes?

A. The Embedded Cost Differential Adjustments, both costs and credits, are allocated on Factor 10 (75 percent Demand and 25 percent Energy), the same basis as the underlying costs of the resources.

Description of Cost of Service Procedures

Q. Please explain how the Cost of Service Study was developed.

A. Using the FY04 annual results of operations for the State of Idaho filed by Mr. Weston, the study employs a three-step process generally referred to as functionalization, classification, and allocation. These three steps recognize the way a utility provides electrical service and assigns cost responsibility to the groups of customers for whom those costs were incurred.

Q. Please describe functionalization and how it is employed in the Cost of Service Study.

A. Functionalization is the process of separating expenses and rate base items according to utility function. The production function consists of the costs associated with power generation, including coal mining, and wholesale purchases. The transmission function includes the costs associated with the high voltage system utilized for the bulk transmission of power from the generation source and interconnected utilities to the load centers. The distribution function includes the costs associated with all the facilities that are necessary to connect individual customers to the transmission system. This includes distribution substations, poles and wires, line transformers, service drops and meters. The retail services function includes the costs of meter reading, billing, collections and customer service. The miscellaneous function includes costs associated with Demand Side Management, franchise taxes, regulatory expenses, and other miscellaneous expenses.

Q. Describe classification and explain how PacifiCorp uses it in the cost of service study.

A. Classification identifies the component of utility service being provided. The Company provides, and customers purchase, service that includes at least three different components: demand-related, energy-related, and customer-related. Demand-related costs are incurred by the Company to meet the maximum demand imposed on generating units, transmission lines, and distribution facilities. Energy-related costs vary with the output of a kWh of electricity. Customer-related costs are driven by the number of customers served.

Q. How does PacifiCorp determine cost responsibility among customer groups?

A. After the costs have been functionalized and classified, the next step is to allocate them among the customer classes. This is achieved by the use of allocation factors that specify each class' share of a particular cost driver such as system peak demand, energy consumed, or number of customers. The appropriate allocation factor is then applied to the respective cost element to determine each class' share of cost. A detailed description of PacifiCorp's functionalization, classification and allocation procedures and the supporting calculations for the allocation factors are contained in my work papers.

Q. How are generation and transmission costs apportioned among customer classes?

A. Production and transmission plant and non-fuel related expenses are classified as 75 percent demand related and 25 percent energy-related. For non-seasonal resources, the demand-related portion is allocated using 12 monthly peaks coincident with the PacifiCorp system firm peak. The energy portion is allocated using class MWhs adjusted for losses to generation level. As previously discussed, for Seasonal Resources the process is very similar. The only difference is that prior to summing each class' twelve monthly Coincident Peaks or monthly energy usage, the monthly values are weighted by the monthly portion of the total annual energy generated or delivered to PacifiCorp by the Seasonal Resource.

Q. Are distribution costs determined using the same methodology?

A. No. Distribution costs are classified as either demand-related or customer-related. In this study, only meters and services are considered as customer-related with all other costs considered demand related. Distribution substations and primary lines are allocated using the weighted monthly coincident distribution peaks. Distribution line transformers and secondary lines are allocated using the weighted NCP method. Services costs are allocated to secondary voltage delivery customers only. The allocation factor is developed using the installed cost of new services for different types of customers. Meter costs are allocated to all customers. The meter allocation factor is developed using the installed costs of new metering equipment for different types of customers.

Q. Please explain how customer accounting and customer service expenses are allocated.

A. Customer accounting expenses are allocated to classes using weighted customer factors. The weightings reflect the resources required to perform such activities as meter reading, billing, and collections for different types of customers. Customer service expenses are allocated on the number of customers in each class.

Q. How are administrative & general expenses, general plant and intangible plant allocated by PacifiCorp?

A. Most general plant, intangible plant, and administrative and general expenses are functionalized and allocated to classes based on generation, transmission, and distribution plant. Employee pensions and benefits have been assigned to functions and classes on the basis of labor. Costs that have been identified as supporting customer systems are considered part of the retail services function and have been allocated using customer factors. Coal mine plant is allocated on the energy factor.

Q. Are costs and revenues associated with wholesale and non-tariff contracts included in the cost of service study?

A. No costs are assigned to wholesale contracts. The revenues from these transactions are treated as revenue credits and are allocated to customer groups using appropriate allocation factors. Other electric revenues are also treated as revenue credits. Revenue credits reduce the revenue requirement that is to be collected from firm retail customers.

Q. Have you included cost of service results for the Idaho special contracts?

A. Nu-West, which is on a Tariff Standard contract, is included as single customer class in the Cost of Service Study. Monsanto is on a fixed price contract that was approved under the IPUC Contract Standard and is not eligible for a price change until January 1, 2007. Therefore no costs of service results are shown for Monsanto and are not included in the Cost of Service Study. The revenues from Monsanto are included as an Idaho state specific revenue credit.

Work Papers

Q. Have you included your work papers?

A. Yes. Work papers showing the complete functionalized results of operations and class cost of service detail are included as Exhibit No. 24. Also included in the work papers is a detailed narrative describing the Company's functionalization, classification and allocation procedures.

Q. Does this conclude your direct testimony?

A. Yes, it does.