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

A. My name is David L. Taylor. My business address is 825 NE Multnomah Street, Suite 800, Portland, Oregon 97232. I am employed by PacifiCorp as a Principal Regulatory Consultant.

Qualifications

Q. Please summarize your education and business experience.

A. I received a Bachelor of Science degree in Accounting from Weber State College in 1979 and a M.B.A. from Brigham Young University in 1986. I have been employed by PacifiCorp since the merger with Utah Power in 1989 ("Merger"). 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 direct testimony?

A. My direct testimony covers five areas. First, I describe in general terms the basis and content of the Revised Protocol. In the Second portion of my direct testimony, I provide a detailed explanation of the various elements of the Revised Protocol including the classification and allocation of generation and transmission costs, the treatment of non-tariff Special Contracts and the treatment of Hydro Resources and Qualifying Facilities. Third, my testimony estimates the impact of the Revised Protocol on the future revenue requirements in each State. Fourth, I detail the impacts of the Revised Protocol on the Washington revenue requirement proposed in this case. Finally, my direct testimony presents PacifiCorp's Class Cost of Service Study for Washington based on the test period ending September 2004.

Overview of the Revised Protocol

Q. Please identify Exhibit No.___(DLT-2).

A. Exhibit No.___(DLT-2) is the PacifiCorp Inter-jurisdictional Cost Allocation Protocol ("Revised Protocol") that the Company is requesting that the Commission adopt for purposes of setting the Company's rates in this and future proceeding. The Revised Protocol describes how the costs associated with PacifiCorp's generation, transmission and distribution system will be assigned or allocated among its six State jurisdictions for purposes of establishing its retail rates. As described in the Revised Protocol, PacifiCorp will continue to plan and operate its generation and transmission system on a six-State integrated basis in a manner that achieves a least cost/least risk Resource portfolio for its customers. The Revised Protocol describes regulatory policies which, if followed by all States on a long-term basis, should afford PacifiCorp a reasonable opportunity to recover all of its prudently incurred costs.

Appendix A to the Revised Protocol is a list of defined terms. For purposes of greater clarity and consistency, when I capitalize terms in my direct testimony, it is intended that those terms have the same meaning as provided for in Appendix A to the Revised Protocol. Also attached to the Revised Protocol are Appendices B through F. Appendix B identifies the allocation factors applied to each component of the revenue requirement calculation and Appendix C details the algebraic derivation of each allocation factor. Appendix D provides a description of how Special Contracts are treated, Appendix E details the Embedded Cost Differential Adjustment, and Appendix F contains a description of the calculation of the Mid-Columbia (MC) factor as well as example calculations of the factor.

Q. Which States have adopted the Revised Protocol?

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

Background of MSP Revised Protocol

Q. How did the Company develop the Revised Protocol?

A. There were widely divergent views expressed during the course of the Multi-State Process ("MSP"). However, it appeared that all MSP participants shared the belief that the ultimate resolution of MSP issues should be based upon sound public policy and economic principles, and should not be a result of "horse trading" aimed only at achieving an agreeable short-term economic outcome. Therefore, in formulating the Revised Protocol, we sought to harmonize, as best as we were able, the principle-based positions taken by the various MSP participants.

Q. Does that mean that MSP participants were unconcerned about customer price impacts?

A. By no means. It seemed to be generally understood and agreed that the MSP should not result in a disproportionate cost shift among States. To ensure that these cost shifts did not occur, we calculated the estimated price impacts on the States associated with the various approaches, as described more fully in Mr. Duvall's testimony. This evaluation of impacts on individual States was similar to the type of analysis typically used when determining how to implement the results of a cost of service study when spreading the revenue requirement and designing rates, *i.e.*, avoiding the mechanical application of results of a given study in favor of using judgment and taking customer impacts into account.

Q. What other principles formed the basis for the Revised Protocol?

A. It was generally recognized that a resolution to MSP issues should:

a) promote economic efficiency;
b) equitably allocate costs using sound principles of cost-causation;
c) be equitable to PacifiCorp's customers and shareholders;
d) allow individual States to pursue policy initiatives without burdening customers in other States;
e) permit continued effective regulatory oversight; and
f) not impede the provision of safe, adequate and reliable service by the Company.

While these principles enjoyed broad support, there is a tension among them. In addition, MSP participants had differing views regarding the appropriate balance of policy considerations.

Q. Please provide an example of this tension.

A. In order to promote continued effective regulatory oversight, a proposal should be relatively simple and reasonably understandable to customers. Formulating a proposal that is responsive to individual State policy preferences, however, inevitably increases complexity. The challenge is striking the appropriate balance between these two important policy objectives.

Q. Does the Company believe that the Revised Protocol furthers each of the policy principles that you listed previously?

A. Yes.

Q. How does the Revised Protocol promote economic efficiency?

A. Under the Revised Protocol, the Company will continue to plan and operate its system on an integrated basis with the objective of minimizing total costs to our customers.

Q. Is the Revised Protocol equitable from both a customer and shareholder perspective?

A. Yes. From a customer perspective, we believe that the Revised Protocol will result in each State reasonably supporting the costs it is imposing on PacifiCorp's system. We are mindful of the concerns of some States that the expected higher load growth in Utah is being subsidized by slower-growing States. However, analyses conducted during the MSP appeared to demonstrate that Load-Based Dynamic Allocation Factors are effective in directing adequate levels of costs to faster-growing States. Mr. Duvall's direct testimony describes these analyses.

Additionally, the Revised Protocol contemplates that the costs of certain Seasonal Resources are allocated in a manner that better reflects that seasonal usage. This ensures that summer peaking States bear a higher proportion of the costs of summer resources and that winter peaking States bear a higher proportion of the costs of winter resources.

From a shareholder perspective, the Revised Protocol is equitable because it should afford the Company a reasonable opportunity to recover 100 percent of its prudently incurred costs, without any short-fall arising from inconsistent inter-jurisdictional cost allocation methods.

Q. How does the Revised Protocol allow individual States to pursue policy initiatives without burdening customers in other States?

A. The Revised Protocol accommodates individual State policy initiatives in a number of respects. For example:

a) It permits a State to adopt a Direct Access Program without shifting costs to other States;

b) It permits each State to invest in the level of Demand-Side Management Programs it deems appropriate;

c) It permits each State to adopt Portfolio Standards without unreasonably shifting costs to other States;

d) It permits States to afford industrial customers discounts which support economic development without shifting costs to other States; and

e) It permits States in the Pacific Northwest to invest in the Company's hydro-electric facilities so as to enhance the surrounding environment and fish habitat without shifting costs to other States.

Q. Does the Revised Protocol permit continued effective regulatory oversight?

A. Yes. Just as in the past, individual State Commissions will retain full regulatory oversight over the rate making process and other key elements of the Company's relationships with its customers. The Revised Protocol is consistent with allocation practices followed previously in all of our jurisdictions. It incorporates elements of the "rolled-in" method that has been relied upon in Utah. A form of "Hydro Endowment" has been used by a number of our States for more than a decade. Perhaps most importantly, the Revised Protocol is supported by an extraordinary level of analysis which should reduce the likelihood of unintended consequences.

Q. Will the Revised Protocol enhance the Company's ability to provide safe, adequate and reliable service?

A. Absolutely. As described in Mr. Furman's testimony, the Revised Protocol will permit the Company to make needed, cost-effective investments in Resources and transmission with a reasonable degree of confidence that it will be able to recover 100 percent of its prudently incurred costs.

Allocation of Generation-Related Costs

Q. How are generation-related costs allocated under the Revised Protocol?

A. This is provided for in Section IV of the Revised Protocol. All generation Resources will be assigned to one of four categories for inter-jurisdictional cost allocation purposes and reflected on a cost-of-service basis. These categories are: (a) "Seasonal Resources," (b) "Regional Resources," (c) "State Resources," and

(d) "System Resources." There are three types of Seasonal Resources, one type of Regional Resource and three types of State Resources. The remainder are System Resources which constitute the substantial majority of PacifiCorp's Resources.

Seasonal Resources

Q. What are "Seasonal Resources"?

A. The Protocol defines "Seasonal Resources" as: (a) a Simple-Cycle Combustion Turbine generating plant owned or leased by the Company, (b) any Seasonal Contract, or (c) the combination of Cholla Unit IV and the APS Exchange. Mr. Duvall's testimony provides the details of the resources in this category and the rationale for their inclusion.

Q. What is the basis for allocating the costs of Seasonal Resources?

A. The different treatment is intended to gain a measure of precision and assure that costs are allocated equitably. We experience peak loads in the eastern part of the system during summer months. We experience peak loads in the western part of the system during winter months. Seasonal Resources are acquired in large measure to meet these peak loads. Therefore, it appears equitable to allocate the costs of Seasonal Resources in a manner that better reflects the seasonal peaking differences of our States.

Q. How are the costs of Seasonal Resources allocated?

A. Generally speaking, costs of Seasonal Resources are more heavily assigned to the months in which the Resource is dispatched and, by extension, to the States with the greatest proportion of load on the system during those months. I describe the allocation process in detail later in my testimony.

Regional Resources

Q. What are "Regional Resources"?

A. Regional Resources include (a) the Company's owned Western Control Area hydro-electric facilities, (b) contracts under which the Company purchases power from the "Mid-Columbia" projects, and (c) contracts entered into by PacifiCorp to directly amend or replace the Mid-Columbia contracts. Mr. Duvall's testimony provides the details of the resources in this category.

The treatment of Regional Resources is captured in the Hydro Endowment, which realigns the low cost benefits of these Resources through an "embedded cost differential" (ECD) adjustment. I describe the ECD Adjustments in detail later in my testimony.

Q. What is the basis for allocating the low cost benefits of Hydro-Electric Resources in this manner?

A. The proposed difference in treatment arises from the principles of equity and facilitating individual State policy initiatives. Parties in Oregon and Washington feel very strongly that the low cost benefits of Hydro-Electric Resources should flow to customers in the Northwest through a "Hydro Endowment" because that is where the generation is located and where hydro-electric facilities and the mitigation of their impact on fish have long been critical policy concerns. In addition, several parties feel that the former Pacific Power jurisdictions of Oregon, California, Washington and Wyoming have an entitlement to these historically low-cost resources because these Resources predated the Merger.

Those same parties also acknowledge that the States receiving the low cost benefits should support all of the costs of these Resources (which is not the current practice). At the current time, many of the Company's Hydro-Electric Resources are in the process of relicensing at the Federal Energy Regulatory Commission (FERC). As part of this relicensing, FERC is required to consider fish and wildlife, cultural, recreational, land-use and aesthetics issues equally with energy production needs. State and Federal agencies also have the authority to place mandatory conditions in new licenses and certification is required by the State Department of Ecology. Mandatory conditions from the Pacific Northwest States may require investment in fish mitigation measures that exceeds the level with which our other States would be comfortable. Treating Hydro-Resources as Regional Resources permits the Pacific Northwest States to make such policy choices and bear the costs of such choices without risk to our customers in other States.

<u>State Resources</u>

Q. What are State Resources?

A. State Resources consist of: (a) Demand Side Management Programs, (b) Portfolio Standards, and (c) Qualifying Facilities (QF) Contracts

Q. What is the basis for assigning the costs of State Resources?

A. The assignment of the costs of State Resources is based upon the principles of being responsive to individual state policy initiatives and equity. State Resources are driven by state-specific policy initiatives and should, therefore, not unfairly burden other States. The Protocol provides for direct or "situs" assignment of certain costs so as to insulate other States from actions taken by one State.

a. Demand-Side Management Programs

Q. How does the Revised Protocol allocate the costs and benefits of Demand-Side Management (DSM) Programs?

A. Costs of these programs are assigned on a situs basis to the State in which the investment is made. Benefits from these programs, in the form of reduced consumption, will be reflected through time in each State's Load-Based Dynamic Allocation Factors.

Q. Is this consistent with the Company's previous practice?

A. Yes. Situs assignment of DSM costs has been the Company practice since the time of the Merger. The appropriate allocation of the costs and benefits of Demand-Side Management Programs was revisited at some of the earlier MSP meetings. Parties appeared to be satisfied that this approach permitted individual States to invest in the level of DSM Programs that they deemed appropriate without unreasonably shifting costs or benefits to other States with different levels of DSM Program investment.

b. Portfolio Standards

Q. What are Portfolio Standards?

A. The Revised Protocol defines "Portfolio Standards" as any "New State law or regulation that requires PacifiCorp to acquire: (a) a particular type of Resource, (b) a particular quantity of Resources, (c) Resources in a prescribed manner, or (d) Resources located in a particular geographic area."

Q. Can you point to any examples of Portfolio Standards?

A. Yes. Utah, California and Washington have considered legislation requiring utilities to purchase minimum quantities of renewable resources.

Q. Does this mean that Portfolio Standards are limited to laws and regulations related to requirements to purchase renewable resources?

A. No. It is entirely conceivable that a State could require the Company to acquire and locally site a non-renewable Resource for economic development purposes.

Q. Are all Resources acquired as result of Portfolio Standards to be deemed "State Resources," with a situs assignment of all of their costs?

A. No. Only the portion (if any) of the costs of such Resources that are disallowed in other States would be assigned on a situs basis.

Q. Why do you say "if any"?

A. There is no reason to assume that Resources acquired pursuant to Portfolio Standards will not be cost-effective and not properly subject to allocation as System Resources. Situs assignment would occur only if a State requires the Company to make an uneconomic investment. We expect this will be the exception rather than the rule.

c. <u>Qualifying Facilities</u>

Q. Why are QF Contracts included as State Resources?

A. QF Contracts may have substantially different prices in different States. This is particularly the case for Existing QF Contracts, which reflect different State policies that were in effect at the time in which they were executed. These prices do not necessarily reflect market derived prices and may differ substantially from the costs of other resources. A consistent theme in the MSP discussions is that costs arising from individual State policies should be borne by customers in the State making the policy. In the case of Existing QF Contracts, this is accomplished through another embedded cost differential adjustment similar to the ECD used with the Hydro Endowment. I describe the ECD Adjustments in detail later in my testimony.

Q. Why is the embedded cost differential charge/credit being applied only to Existing QF Contracts and not to New QF Contracts?

A. There are two primary reasons. First, an underlying provision of the Revised Protocol is that all States share in the cost of new Resources. If the costs of New QF Contracts are equal to the costs of other new Resources, there is no negative impact on other States and no reason to make a situs assignment of additional costs. Only if New QF Contracts are more expensive than the costs of Comparable Resources is there an impact on other States. Second, there was substantial concern that applying the embedded cost differential approach in respect to New QF Contracts could distort the Company's new Resource acquisition process and create an unfair bias against New QF Contracts.

System Resources

Q. What are "System Resources"?

A. System Resources constitute the substantial majority of PacifiCorp's Resources. The Revised Protocol defines "System Resources" as any Resources that are not "Seasonal Resources," "Regional Resources," or "State Resources."

Q. How are costs and revenues associated with System Resources allocated?

A. All costs and revenues associated with System Resources are allocated on a dynamic basis based upon each State's relative contribution to PacifiCorp's system peak and energy requirements.

Q. What do you mean by your reference to an allocation being done on a "dynamic basis"?

A. I am referring to the practice of basing a State's allocation of costs on its relative contribution to our capacity or energy requirements during the test period for which prices are being established. These allocations are "dynamic" because they change from year to year as the relative size and shape of loads in our various States change through time.

Allocation Procedures under the Revised Protocol

Q. Please summarize the procedures that the Company proposes to follow in allocating the costs of generation Resources.

A. The allocation of a utility's costs employs a three-step process generally referred to as "functionalization," "classification," and "allocation." The use of these three steps recognizes the way a utility provides electrical service and attempts to assign cost responsibility to the groups of customers for whom those costs were incurred.

Functionalization – the process of separating expenses and rate base items between the generation, transmission, and distribution functions – was generally not at issue in MSP.

Classification is the process of separating costs between those which are Demand-Related, Energy-Related, or Customer-Related. Demand-Related costs are the capital and other fixed costs incurred by the Company in order to be prepared to meet the maximum Demand imposed on generating units, transmission lines, and distribution facilities. Energy-Related costs are costs (such as fuel costs) that vary with the amount of Energy actually generated plus any portion of Fixed Costs that have been classified as Energy-Related. Customer-Related costs are those that are primarily driven by the number of customers served.

Allocation is the process of assigning Demand-, Energy-, and Customer-Related costs among States or customer groups. This is achieved by the use of allocation factors that specify each State's share of a particular cost driver such as system peak demand, energy consumed, or number of customers. The appropriate allocation factor determines each State's share of cost.

With the exceptions that I will describe later, the Revised Protocol is an integrated system methodology where customer loads are deemed to be served from a common Resource portfolio. The Revised Protocol deals only with the allocation of costs among States. The procedures for allocation of costs among customer classes will continue to be determined independently by each State.

<u>Classification of Generation Costs</u>

Q. How are generation costs classified under the Revised Protocol ?

A. Generation fixed costs and firm Wholesale Contracts continue to be classified as 75 percent Demand-Related and 25 percent Energy-Related. PacifiCorp found no compelling reason to change from its current practice. The Revised Protocol also continues the practice of classifying fuel costs and non-firm wholesale purchases and sales as 100% Energy-Related. Commissions have generally found that these methods have a reasonable basis in cost causation and changing them would have unwarranted impacts on State revenue requirements.

A discussion paper on the topic of Classification and Allocation of Generation Fixed Costs is presented as Exhibit No.___(DLT-3). The paper reviews some of the classification and allocation history at PacifiCorp and its predecessor companies. It also draws from the 1992 NARUC *Electric Utility Cost Allocation Manual*, which catalogues a number of classification methods commonly employed by utilities.

It is not uncommon to classify all Fixed Costs as Demand-Related since, in general, system capacity must be sufficient to meet maximum demand and thus costs are said not to vary with respect to energy output. On the other hand, engineering analyses employing system reliability criteria in system planning might reveal that the Fixed Costs of generation plant production are both Demand- and Energy-Related, as would analyses showing that peak demand should be met with peaking plant while additional energy loads should be met with intermediate and baseload plant. This is said to justify classifying some portion of production plant costs as energy related.

Pages four through six of Exhibit No.___(DLT-3) applies the methods discussed in the NARUC *Manual* to PacifiCorp's State peak and energy load data and produced a range of results. Demand-Related production costs could vary from 100 percent, to a low end of 27 percent using the "Average and Excess Demand" method. The Company also surveyed a number of electric utilities serving in other states, finding wide classification differences among them.

The choice of the 75 percent Demand/25 percent Energy classification for generation and transmission plant was the final allocation decision made by the PacifiCorp Inter-Jurisdictional Taskforce on Allocations ("PITA") after the Merger. The PITA analysis also indicated that a wide range of demand and energy classification methods could be supported on a technical basis. The demand/energy classification was the means ultimately used to balance the sharing of merger benefits among all the States. The 75 percent Demand/25 percent Energy classification method was selected because it produced an overall cost allocation result that was acceptable to all the States.

Because no clearly superior demand/energy classification split has emerged from analyses conducted during MSP, and because the 75 percent Demand/25 percent Energy classification of generation Fixed Costs currently used by PacifiCorp falls in the middle of the range of reasonable approaches, we propose to continue to use it for all System, Regional and Seasonal Resources.

<u>Allocation of Generation Plant</u>

Q. How is the Demand-Related component of generation costs allocated?

A. As with the issue of the demand/energy classification, the Company found no compelling evidence to support a change from the current 12 Coincident Peak ("12 CP") allocation factor for the demand component of System and Regional Resources. We did, however, determine that certain Resources, identified as

"Seasonal Resources," were acquired and dispatched to meet customer needs during either the winter or summer periods. To match the cost of these Seasonal Resources with their use, costs are apportioned across the months of the year consistent with their dispatch. I will discuss this in greater detail later in my testimony as I review each Resource type.

Q. How did the Company decide to use a 12 CP method to allocate the demand component of System and Regional Resources?

A. Since the time of the Merger, PacifiCorp's Demand-Related Costs of generation Resources have been allocated using the12 CP Factor where all months of the year are deemed to play an equal role in Demand-Related cost causation. To determine if a smaller subset of monthly peaks might form a better basis for Demand-Related Cost allocation, PacifiCorp revisited the stress factor analysis that was employed at the time of the Merger.

Q. What is stress factor analysis?

A. Stress factor analysis is a tool used to identify particular months for inclusion in the capacity allocation factor by examining, month by month, the key elements that stress the ability of the system to meet its peak load requirements and therefore drive the need for investment in new capacity. PacifiCorp examined monthly historical and forecast data for three specific stress factors: (a) monthly retail peak demand, (b) probability of loads in any hour to contribute to the system peak, and (c) the cost to bring the reserve margin to 15 percent.

Q. Please briefly explain the basis for each of these stress factors and how it is calculated.

A. Monthly retail peak, also referred to as the monthly Coincident Peak, is one of the most common stress factors. It is the simplest to calculate and perhaps the easiest to understand. It is the single highest combined demand measurement of all PacifiCorp retail customers during each month. The Company needs enough available generating capacity to meet this level of load. Months with higher peak loads are viewed to place more stress on the system than months with lower peak loads.

The probability of contribution to the system peak indicates the number of hours in each month with loads that exceed a threshold demand level. The criterion for our analysis was the average available energy from PacifiCorp's owned and long-term purchased resources divided by the maximum peak capacity of those same resources, or approximately 83 percent. If the load in any hour of the year exceeds 83 percent of the annual system peak, it is considered to contribute to the system peak. Months where more hours contribute to the system peak are considered to place more stress on the system than months where fewer hours contribute to the peak.

The cost to bring the reserve margin to 15 percent identifies months where the Company's owned plus long-term purchased resources are insufficient to meet the reserve adjusted peak load and captures the magnitude of that shortfall. Months where the cost to achieve the reserve margin is greater are considered to be more stressful on the system than months where the cost is less, or even zero.

The cost is calculated by subtracting the available generating capacity from the reserve adjusted monthly peak load, or peak load plus 15 percent. When this value is positive, it is multiplied by the monthly cost of capacity. For our purposes, the monthly capacity cost of a simple cycle combustion turbine was used.

Q. How were the results of the stress factor analysis used?

A To enable a common comparison between the three stress factors and to make comparisons between months of a given year and between different years, several techniques were used. A method referred to as "rationalizing" – where the peak demand, or other measured value, of a given month is stated as a percentage of the maximum measurement for the year – seemed to be the favored approach.

Exhibit No.___(DLT-4) summarizes the results of the stress factor analysis for the forecast years 2004 through 2008. The monthly-rationalized percents for each stress factor are shown in columns (A) through (C). Column (D) shows the simple average of the three factors and column (E) shows a weighted average with the monthly peak value given double weight.

As shown in column (A), the monthly retail peak is generally the greatest in July or August. The peaks for all months of the year, however, are within 80 percent of the annual peak with eight months of the year, June through September and November through February, within 90 percent of the annual peak. Only the April peak is less than 85 percent of the annual peak.

The probability of contribution to system peak is summarized in column (B). While the probability of summer hours contributing to the peak is the greatest, the analysis also shows strong probabilities during the winter months. It also suggests that, with the exception of April, there are hours in all months of the year that contribute to the system peak.

The analysis summarized in column (C) indicates that the cost to bring reserve margin to 15 percent is again greater in the summer with the winter costs only about half of that in the summer.

The stress factor analyses suggest that winter and summer loads may be more significant Demand-Related cost drivers than spring and fall loads. We have addressed this by segregating Seasonal Resources from other Resources. As mentioned earlier, and as will be discussed in greater detail later in my testimony, the costs of Seasonal Resources will be assigned to the months those Resources are dispatched to meet retail load. The seasonal weighting will assign a larger portion of the Demand-Related costs to the summer and winter months. With this adjustment for Seasonal Resources, the continued use of the 12 CP Factor for the remaining Resources appears even more reasonable.

Q. How does the 12 CP Factor work?

A. The 12 CP Factor determines the proportional share of annual Demand-Related costs that are allocated to each State. For each month of the year, the Coincident Peak, or the hour during which the combined demand of all PacifiCorp retail customers is the greatest, is identified. For that hour, each State's contribution to the Coincident Peak, the combined demand of all retail customers in that State, is measured in megawatts. Each State's contributions to the twelve monthly system peaks are summed to establish the State's 12 CP measurement. The 12 CP Factor is calculated by dividing each State's 12 CP by the sum of the twelve monthly total system Coincident Peaks or, in the case of Regional Resources, by the aggregate sum of the twelve monthly Coincident Peaks of the participating States.

Q. How is the hour of system peak for each month determined?

A. The hour of system peak is based on metered load data. For each hour of the month, all inputs into the system such as Company-owned generation, purchases or interchanges are measured. From that measurement, all deliveries outside the system or to non-retail customers are deducted to arrive at total retail load. The Coincident Peak is the hour of each month during which the combined demand of all retail customers is the greatest.

Each State's contribution to hourly loads is determined in essentially the same way. Each State's hourly load consists of the Company owned generation within that State, purchases or interchanges delivered into the State, plus metered flows of energy into the State from other parts of the PacifiCorp system. From that measurement, metered and scheduled energy flows out of the State and deliveries to non-retail customers are deducted to arrive at that State's retail load.

Allocation of Energy Costs

Q. How does the Revised Protocol allocate fuel and other Energy-Related costs?

A. For System and Regional Resources, fuel and other Energy-Related Costs are allocated using each participating State's share of annual system energy usage. For each type of Seasonal Resource, Energy-Related Costs are allocated using weighted monthly energy usage.

Cost Allocation for Seasonal Resources

Q. Why are the costs of Seasonal Resources allocated differently from the remainder of its Resources?

A. Seasonal Resources are designed to be used more intensively at certain times of year. The costs of Seasonal Resources are allocated in a way that better reflects the seasonal peaking differences of our States.

Q. How is the allocation of Demand-Related and Energy-Related costs different for Seasonal Resources?

A. The process for Demand-Related costs is very similar to the 12 CP allocation method used for System Resources. The only difference is that prior to summing the twelve monthly Coincident Peaks, each monthly CP measurement is weighted by the monthly portion of the total annual energy generated by the Seasonal Resource. For example, if 30 percent of the annual generation of 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.

The process for Energy-Related costs is similar. Each State's energy usage measurement in a given month is weighted by the portion of the total annual energy generated by the Seasonal Resource in that month. The sum of the 12 weighted monthly energy values is then used to calculate the allocation factor for the Energy-Related costs.

Somewhat different procedures are used for simple-cycle combustion turbines, Seasonal Contracts and the costs of Cholla Unit IV.

<u>Simple Cycle Combustion Turbines</u>

Q. How does the Revised Protocol classify and allocate the costs of Simple-Cycle Combustion Turbines (SCCTs)?

A. As described earlier in my testimony, the fixed costs of SCCTs are classified as 75 percent Demand- and 25 percent Energy-Related. Both the Demand-Related and Energy-Related Costs are then assigned to the individual months of the year on the proportional basis of the annual dispatched MWh's for the given month in which those resources are dispatched to meet retail load. Mr. Duvall describes how these values are determined. The aggregate Demand-Related Costs of the turbines are allocated to States using the Simple-Cycle Combustion Turbine dispatch weighted 12 CP (Seasonal System Capacity Combustion Turbine or SSCCT) allocation factor and the Energy-Related Costs are allocated using the Simple-cycle Combustion Turbine dispatch weighted Energy (Seasonal System Energy Combustion Turbine or SSECT) allocation factor. This process was described earlier in my testimony.

Because existing SCCTs are dispatched more heavily during the summer months, the majority of their costs are allocated using summer loads.

<u>Seasonal Contracts</u>

Q. Are the costs of Seasonal Contracts allocated in the same way as SCCTs?

A. Generally, yes. As with the Simple-Cycle Combustion Turbines, the costs of Seasonal Contracts will be 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-Related and allocated to States using the seasonally weighted (Seasonal System Generation Purchases or SSGP) allocation factor.

Cholla Unit IV

Q. Are there any other Resources that are more heavily used in one season of the year?

A. Yes. 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.

Q. How are the costs of Cholla Unit IV allocated under the Revised Protocol?

A. 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.

As with other Resources, Cholla fixed costs are classified as 75 percent Demand/25 percent Energy. The Fixed Costs are allocated using the Seasonal System Generation Cholla (SSGCH) allocation factor and fuel costs are allocated using the Seasonal System Energy Cholla (SSECH) allocation factor.

Cost Allocation for Regional Resources

Hydro-Electric Resources

Q. Please explain how the costs of Hydro-Electric Resources are assigned and allocated under the Revised Protocol.

A. In the Revised Protocol, the existing and future investment and the operating costs of Hydro-Electric Resources are first allocated on a system-wide basis. Then, the total normalized costs of Hydro-Electric Resources are compared against the normalized costs of the remaining generation portfolio on a $/MWH basis and an adjustment which reflects the cost difference is applied. This adjustment is referred to as "The Owned-Hydro Embedded Cost Differential Adjustment."

The Owned-Hydro Embedded Cost Differential Adjustment is calculated as the Annual Embedded Costs – Hydro-Electric Resources, less the Annual Embedded Costs – All Other, multiplied by the normalized MWh's of output from the Hydro-Electric Resources used to set rates. The adjustment is then allocated to former Pacific Power jurisdictions using the DGP factor. The original system allocation of the low cost benefit is then reversed by allocating the reciprocal amount (All Other less Hydro) to all States using the SG factor. Currently the adjustment is negative (the Hydro-Electric Resource costs are less expensive than all other Resources), so it is a net credit to the former Pacific Power jurisdictions and a cost to the other jurisdictions.

Mid-Columbia Contracts

Q. Please explain how the costs of Mid-Columbia Contracts are assigned and allocated under the Revised Protocol.

A. Similar to Hydro-Electric Resources, the costs of Mid-Columbia Contracts are first allocated on a system-wide basis. Then, the total normalized costs of Mid-Columbia Contracts are compared against normalized costs of the remaining generation portfolio on a $/MWh basis and an adjustment which reflects the cost difference is applied. This adjustment is referred to as the "Mid-Columbia Contracts Cost Differential Adjustment."

The Mid-Columbia Contracts Cost Differential Adjustment is calculated as the Annual Mid-Columbia Contract Costs, less the Annual Embedded Costs – All Other, multiplied by the normalized MWh's of output from the Mid-Columbia Contracts. The adjustment is then allocated to all States using the Mid-Columbia (MC) factor and the reciprocal amount (All Other less Mid-C) is allocated to all States using the SG factor.

The calculation of the MC factor is shown in Appendix F of the Revised Protocol and described in detail in Mr. Duvall's Direct Testimony.

Existing QF Contracts

Q. Please describe how the costs of Existing QF Contracts are assigned and allocated under the Revised Protocol.

A. Existing QF Contracts are treated similarly to the Hydro Resources and the Mid-Columbia Contracts. Like Hydro-Electric Resources, the costs of Existing QF Contracts are first allocated on a system-wide basis. But then, unlike the Hydro

Electric Resource and Mid-Columbia Contract costs, which are compared to other generation costs at an aggregate level, the Existing QF cost difference is calculated separately for each State. The Existing QF Contract costs in each State are compared against normalized costs of the remaining generation portfolio on a $/MWh basis and an adjustment which reflects the cost difference is applied. This adjustment is referred to as "Existing QF Contracts Cost Differential Adjustment."

The Existing QF Contracts Cost Differential Adjustment is calculated as the Annual Existing QF Contracts Costs for a specific State, less the Annual Embedded Costs – All Other, multiplied by the normalized MWh's of output from that State's Existing QF Contracts. This adjustment is situs assigned to that State. The sum of this adjustment for all States is calculated and an adjustment for the reciprocal amounts (All Other less Total System QF) is allocated to all States using the SG factor.

Embedded Cost Differential Calculation

Q. How are the Company's Annual Embedded Costs calculated?

A. Annual Embedded Costs are calculated for Hydro-Electric Resources, Mid-Columbia Contracts, Existing QF Contracts, and all other Resources. They are based on fully normalized test period costs captured in the FERC accounts identified in Appendix E to the Revised Protocol.

As shown on lines 1 through 11 of Appendix E, 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, $70,969,571 in this example. This amount is divided by the annual hydro MWh, from the GRID run used in the test period net power cost calculation, 4,128,973 MWh, to arrive at the Annual Embedded Costs – Hydro-Electric Resources of $17.19 per MWh.

The Annual Costs, MWh, and corresponding cost per MWh are shown for Mid-Columbia Contracts and total Existing QF Contracts on lines 12 and 13, respectively.

The Annual Embedded Costs – All Other are shown on lines 14 through 44. This calculation is similar to the costs for Hydro-Electric Resources described above and results in Annual Embedded Costs – All Other of $32.00 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.

The Embedded Cost Differential calculation for the September 2004 test period in this case is found in Exhibit No.____(DLT-6).

Q. Did the Company evaluate alternatives to the Embedded Cost Differential as a form of Hydro Endowment?

A. Yes. The following three alternatives to the Embedded Cost Differential were proposed and evaluated in the course of the MSP:

- Combining the Hydro Endowment with a Coal Endowment,
- Using or modifying the fuel adjustment mechanism, and
- Reinstating a load decrement approach.

I will discuss the reasons for the rejection of these approaches in favor of the "embedded cost differential."

Q. Why did the Company abandon its earlier proposal to combine the Hydro Endowment with a Coal Endowment?

A. It did not enjoy support from MSP participants.

Q. Please describe the "fuel adjustment mechanism."

A. The fuel adjustment mechanism is part of the Modified Accord allocation methodology. This mechanism:

- Calculates the difference (on a $/MWh basis) between the 5-year average of the O&M Expenses of the Company's Hydro-Electric Resources and the O&M Expenses of the Company's Thermal Resources;
- Multiplies the $/MWh difference by the MWh's of generation from Hydro-Electric Resources, and then allocates the difference as a credit to the former Pacific Power jurisdictions and as a charge to all jurisdictions; and
- Allocates the costs of post-1989 capital investments across the system based on each State's proportional load in a test period.

A corresponding calculation is also calculated for the former Utah Power Hydro-Electric Resources.

Q. Please discuss the drawbacks of the existing fuel adjustment mechanism.

A. One primary drawback is that the mechanism compares only the operating costs of thermal Resources and the operating costs of Hydro-Electric Resources and therefore does not account for the Fixed Costs of either type of Resource. Another problem is that it does not equitably match the distribution of the fuel cost benefits of Hydro-Electric Resources with the responsibility for the expected substantial increase in capital costs for the relicensing and other capital investments associated with Hydro-Electric Resources. That is to say, under Modified Accord, all States would bear a proportionate share of post Merger Hydro-Electric Resource capital costs, but only former Pacific Power States would receive the fuel cost advantage of Hydro-Electric Resources.

Q. Did parties consider options that would address these inequities?

A. Yes. Parties evaluated a short-term fuel adjustment mechanism that phased out as the revenue requirement of relicensing costs exceeded the fuel benefits. However, this approach did not eliminate the inequities. This mechanism incorporated a mismatch of costs in that it involved a comparison of both the Fixed Costs and Variable Costs of Hydro-Electric Resources against only the Variable Costs of thermal Resources. Again, some States received credits for fuel benefits for the next several years but all States bore the risk of the costs of relicensing. Additionally, this approach was rejected by some parties because it was not permanent.

Q. Please describe the "load decrement approach."

A. Under the load decrement approach, the costs of Hydro-Electric Resources are assigned to and allocated among the former Pacific Power jurisdictions. At the same time, the loads of the former Pacific Power jurisdictions are reduced by the output of the Hydro-Electric Resources, prior to the development of allocation factors for the remaining System Resources. This reduces the Pacific Power jurisdictions' allocated share of the cost of the remaining System Resources. This type of approach was utilized under the Accord Method from 1993 to 1997.

Q. Why isn't the Company proposing to reinstate the load decrement approach?

A. Our studies have revealed drawbacks to this mechanism. Most significantly, the load growth studies revealed that the load decrement approach distorts the allocation of costs associated with load growth to the States with decremented loads. Not only are States with decremented loads allocated a smaller share of existing remaining System Resources, they are also allocated a smaller share of the cost of new System Resources. This is in conflict with the principle that States should pay for the costs of their load growth to the maximum extent possible.

System Resources

Q. What is the allocation procedure for the remaining System Resources?

A. The Fixed Costs of System Resources are allocated using the 75 percent Demand, 25 percent Energy 12 CP (System Generation or SG) allocation factor. Variable Costs for System Resources are allocated using the Annual Energy (System Energy or SE) allocation factor. The basis for these allocation factors and a description of how they are calculated were discussed earlier in my testimony.

Transmission Costs

Q. How does the Revised Protocol classify and allocate transmission costs?

A. Costs associated with transmission assets and firm wheeling expense are classified as 75 percent Demand/25 percent Energy-Related and allocated using the SG allocation factor. Non-firm wheeling expense and revenues are classified as Energy-Related and allocated among the States based upon the SE Factor.

Distribution Costs

Q. Does the Revised Protocol make any changes to the allocation of distribution costs?

A. No. Distribution costs are all directly assigned to individual States and no jurisdictional allocation is required.

Administrative and General (A&G) Costs

Q. Does the change in the allocation of some of the generation plant costs affect the sharing of A&G and other infrastructure costs?

A. Yes, but the impacts appear to be minimal. Historically PacifiCorp has allocated the bulk of A&G expenses, the costs of General Plant and Intangible Plant, and other common costs using a System Overhead (SO) factor. The SO factor is calculated using each State's proportional share of allocated and assigned plant investment. With a change in the allocation for some of the generation assets, there will be a corresponding shift in the allocation of these common costs. To test whether that shift was significant enough to warrant development of a new allocation procedure, the Company compared the allocation of all costs using the SO factor under the proposed method with the allocation of those same costs under the rolled-in allocation method. The impact of the change in the SO factor was approximately plus or minus one percent of system overhead costs and less than 0.15 percent of total State revenue requirements. We did not consider this impact to be large enough to warrant a change in methodology for the allocation of system overhead costs.

Special Contracts

Q. How are Special Contracts treated in the Revised Protocol?

A. Consistent with other parts of the Revised Protocol, if a Commission makes a decision for reasons of local or State interest that would increase costs to customers in other States, the costs of the decision should be borne entirely within the State making the decision. That principle as applied to Special Contracts ensures that customers in Washington will not be adversely impacted by the pricing and other terms of a Special Contract in any other State, while at the same time allowing the Company to acquire cost effective Resources from these customers. To achieve this, the cost of serving contract customer loads, and their State approved retail service revenues, will be included in the local State's revenue requirement on the same basis as would apply to the cost of serving any other retail customer. Any payments made (or discounts provided) for the Customer Ancillary Service Contract attributes, such as operating reserves, system integrity interruption, or economic curtailment, will be treated as a Resource acquisition by the Company and included as a purchased power cost allocated among all States.

As with the establishment of retail tariff prices, the Commission with jurisdiction over a Special Contract will, within the context of the State revenue requirement, have authority to establish the retail service price for the contract. This includes the application of State-specific public policy preferences that may allow Commissions to consider other issues, in addition to costs, when setting retail prices.

Appendix D of the Revised Protocol provides a detailed description of how Special Contracts are treated. Appendix D identifies two general types of Special Contracts: (a) Special Contracts without Customer Ancillary Service Contract attributes, and (b) Special Contracts with Customer Ancillary Service Contract attributes. For both types of Special Contracts, the cost of serving contract customer loads, and their State-approved retail service revenues, will be included in the local State's revenue requirement. However, the regulatory treatment of the two types of Special Contracts is different.

For allocation purposes, Special Contracts without Customer Ancillary Service Contract attributes are viewed as one transaction and the system benefits and load reductions accruing from customer interruptions are treated very similarly to DSM. Like DSM, the host jurisdiction benefits from the reduction in system costs through smaller allocation of total system costs. Specifically, loads of Special Contract customers, which may be lower as a results of interruptions, will be included in all Load-Based Dynamic Allocation Factors. Actual revenues received from a Special Contract customer will be assigned to the State where the Special Contract customer is located.

For allocation purposes, Special Contracts with Customer Ancillary Service Contract attributes are viewed as two transactions. PacifiCorp first sells the customer electricity at the retail service rate. The retail service portion of the Special Contract is a State situs transaction and all aspects of this transaction are reflected in the development of that State's revenue requirement. Loads associated with the retail service to the Special Contract customers will be included in all Load-Based Dynamic Allocation Factors and State revenues are reflected at the retail service rate.

In the second transaction, PacifiCorp then buys electricity back from the customer during the interruption period at the Ancillary Service Contract rate. This second transaction is viewed, not as a reduction in load, but rather as the acquisition of Resources to meet Company load. It is a System Resource acquisition with the costs allocated among all States.

Special Contracts, either with or without Customer Ancillary Service Contract attributes, may include an option that allows the customer to pay hourly market prices (buy-through) rather than be physically curtailed during certain types of interruptions. For regulatory purposes, all elements of a buy-through transaction are ignored and are excluded from the calculation of State revenue requirements. The cost associated with the buy-through will be removed from the calculation of net power costs, the Special Contract customer load associated with the buy-through will be not be included in the calculation of Load-Based Dynamic Allocation Factors, and the revenue associated with the buy-through will not be included in State revenues.

Revenue Requirement Impacts

Q. Have you prepared an exhibit showing the impact of the Revised Protocol on revenue requirements?

A. Yes. Exhibit No.___(DLT-5) presents the estimates of the Revised Protocol impacts on future State revenue requirements. These estimates were made in spring 2004 and included in the filings of Revised Protocol with the various state commissions. Estimated revenue requirements for California, Oregon, Washington, and Wyoming are compared to the Modified Accord methodology. Estimated revenue requirements for Idaho and Utah are compared to the Rolled-In methodology. A positive percent indicates the State's revenue requirement for a given year under the Revised Protocol is higher and a negative percent indicates the revenue requirement under the Revised Protocol is lower. The year-by-year revenue requirement impacts are shown for the period 2005 thorough 2018 as well as the Net Present Value of the difference in revenue requirements over the 14-year period. For each State, the percent change in revenue requirement associated with the effect of moving from Modified Accord to Rolled-In (if applicable), the Hydro Endowment (both Company Owned and Mid-C components), Existing QF Contracts and Seasonal Resources is shown first, followed by the impact of the full Revised Protocol.

Q. What are the important analytical assumptions underlying these calculations?

A. They include projections of Hydro-Electric Resource relicensing costs, expected new Resources as reflected in the Company's 2003 IRP, clean air investments and a carbon tax commencing in 2008.

Q. What factors are not reflected in the calculations?

A. Exhibit No.___(DLT-5) compares only the estimated revenue requirements under the different allocation methodologies. It does not compare current revenues to the estimated revenue requirements or make any projections as to the timing or magnitude of future price changes.

Q. What do you conclude from Exhibit No._____(DLT-5)?

A. I conclude that, in addition to balancing the public policy and cost causation principles discussed at the beginning of my testimony, the revenue requirement impacts of adopting the Revised Protocol are within an acceptable range. While the Revised Protocol produces somewhat lower revenue requirements for Oregon, Washington, and Wyoming in the early years, the trend reverses and those States see larger revenue requirements in the later years. The higher Revised Protocol revenue requirements seen by Utah and Idaho in the early years are offset by lower revenue requirements in the later years. I also conclude that Washington receives the largest net cost benefit of all the States from the Revised Protocol.

Impact of the Revised Protocol in this Case

Q. Have you prepared an exhibit that shows the Washington revenue requirement impacts in this case associated with implementation of the Revised Protocol?

A. Yes. Exhibit No._____(DLT-6) compares the Washington revenue requirement, as calculated by Mr. Wrigley, under the previously used Modified Accord allocation method with the Washington revenue requirement under the Revised Protocol allocation method. Page one of Exhibit No._____(DLT-6) shows the impact of each allocation difference described above. Using the Modified Accord allocation methodology, the target Washington revenue requirement in this case, as shown on line 1, would have been $260.5 million.

Line 2 shows that the impact of moving from the Modified Accord to the Rolled-In jurisdictional allocation is an increase of $6.6 million to the Washington revenue requirement. This is the result of the elimination of the divisional assignment of pre-merger generation and transmission plant investments and the fuel adjustment hydro endowment. Lines 3 through 6 show the offsetting Washington benefits associated with the other elements of the Revised Protocol. As shown on lines 3 and 4, Washington receives a $4.7 million benefit associated with the new Owned-Hydro Embedded Cost Differential Adjustment and a $1.4 million benefit associated with the Mid-Columbia Contracts Cost Differential. Line 5 shows $2.5 million benefit to Washington associated with the Existing Qualifying Facility (QF) Contracts Cost Differential Adjustment. Finally, line 6 shows the $0.6 million benefit to Washington as a result of the seasonally weighted allocation of certain resource costs.

As shown on line 7, the sum of these allocation changes produces a net benefit to Washington customers of $2.7 million. As a result, the $257.8 million Washington revenue requirement requested by the company in this case shown on line 9 is $2.7 million, or 1 percent, lower than the revenue requirement produced by the previously used allocation methodology.

Pages two, three and four of Exhibit No._____(DLT-6) contain the 12 months ended September 2004 results of operations summary using the Revised Protocol, Rolled-In, and Modified Accord allocation methods respectively. Page 5 contains the ECD calculation from the test period in this case.

Washington Class Cost of Service

Summary of Results

Q. Please identify Exhibit No.___(DLT-7) and explain what it shows.

A. Exhibit No.___(DLT-7) is the summary table from PacifiCorp's test period ended September 2004 Class Cost of Service Study for the State of Washington. It is based on PacifiCorp's annual results of operations for the State of Washington presented in the testimony of Mr. Wrigley. It summarizes, both by customer group and by function, the results of the 12 months ending September 2004 Cost of Service Study. Page 1 presents results at the Company's September 2004 Earned Rate of Return. Page 2 presents the results using the rate of return provided by the $39.2 million requested price increase.

Q. Please identify Exhibit No.___(DLT-8) and explain what it shows.

A. Exhibit No.___(DLT-8) shows the cost of service results in more detail.

Description of Procedures

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

A. Using the September 2004 annual results of operations for the State of Washington filed by Mr. Wrigley, the study employs the three-step functionalization, classification, and allocation process.

Q. How is the functionalization process 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 how the classification process is used 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. As described earlier in my testimony, 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 classes?

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 workpapers.

Q. Does PacifiCorp's cost of service study filed in this case follow the methodology filed in the Company's 2003 Washington general rate case (Docket No. UE-032065)?

A. Yes. This cost of service study follows the same methodology as filed in the previous case.

Q. Does the Revised Protocol affect the cost of service methodology employed in the class cost of service study?

A. No. The Revised Protocol is for allocation of costs among states. Each individual state Commission continues to have full independent authority to determine methodology on allocation of costs among customer classes within its state. Some states may choose, as they have in the past, to adopt the same allocation methodologies for class allocation as used in inter-jurisdictional allocation, while other states view the two processes as being more independent. Again, we have made our best efforts to follow major class cost allocation guidelines established by the Commission.

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

A. All production and transmission plant and expenses, including fuel and purchased power, are classified using a peak credit method where the cost of a current peaking resource (Simple Cycle Combustion Turbine, or SCCT) is compared to the cost of a current baseload resource (Combined Cycle Combustion Turbine, or CCCT). In this method, the SCCT is deemed to provide benefits in addition to pure peaking capability, and therefore only one-half of the fixed costs are considered in determining the Demand-Related component. All other costs are considered Energy-Related.

Q. Please identify Exhibit No.___(DLT-9) and explain what it shows.

A. Exhibit No.___(DLT-9) shows the calculation of the demand and energy classification percentages used for generation and transmission costs in the study. In the calculation, one-half of the fixed costs of an SCCT plus the expected operating costs for 200 hours become the numerator. The denominator is the total cost, both fixed and variable, of a CCCT , run at an 85 percent capacity factor, consistent with the Company's resource planning and avoided cost calculations. This calculation produces the 13 percent Demand-Related classification with the remaining 87 percent the Energy-Related classification of costs.

The Demand-Related portion is then allocated using class loads coincident with the PacifiCorp's highest 100 summer (April-October) and 100 winter (November-March) hourly retail system loads. The Energy-Related portion is allocated using class annual MWh's adjusted for losses to generation level.

Q. Why didn't you use the highest 200 peak load hours regardless of season?

A. PacifiCorp is a dual peaking utility with peaks in both the summer and the winter. In the September 2004 test period, nearly all (193 out of 200) of the system peak hours were in the summer. This would have resulted in no Demand-Related generation costs being assigned to electric space heating and other winter loads. At the same time, summer loads, like irrigation and other agricultural loads, would have been assigned the entire annual Demand-Related generation and transmission costs.

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 maximum rate schedule peaks (also identified as class non-coincident peaks). Distribution line transformers are allocated using the weighted non-coincident peak (NCP) method. The costs of secondary lines are also allocated using the weighted NCP method, but are only allocated to residential and small general service customers where line transformers are jointly used by more than one customer. 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. DSM expenditures are allocated on the same basis as generation costs. Other 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 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 consistent with generation and transmission resources.

Q. Are costs and revenues associated with wholesale 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.

Partial Requirements Service

Q. Does the Cost of Service Study include results for partial requirements service customers?

A. No. Cost of service results were not calculated for partial requirements service customers.

Q. Why are these customers removed from the cost of service study?

A. Partial requirements are not included in the embedded cost of service study because they do not lend themselves well to this type of analysis. These customers usually have very sporadic loads from year to year, producing volatile cost of service results depending on whether or not service is required during the hour of monthly system peak. It is the Company's practice to derive prices for this type of service from the prices and costs for full requirements service. The revenues from partial requirements service are allocated back to other classes as revenue credits.

Q. What is included in your workpapers?

A. Workpapers showing the complete functionalized results of operations and class cost of service detail are included as Exhibit No.___(DLT-10). Also included in the workpapers is a detailed narrative describing the Company's functionalization, classification and allocation procedures.

Q. Does this conclude your direct testimony?

A. Yes.