BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION OF INTER- JURISDICTIONAL ISSUES AFFECTING PACIFICORP DBA UTAH POWER & LIGHT CO.	)))))	CASE NO. PAC-E-02-3 DIRECT TESTIMONY OF GREGORY N. DUVALL

SEPTEMBER 2003

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

A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah Street, Suite 300, Portland, Oregon 97232. I am employed by PacifiCorp as Managing Director, Planning and Major Projects.

Qualifications

Q. Please summarize your education and business experience.

A. I received a degree from University of Washington in Mathematics in 1976 and an MBA from University of Portland in 1979. I was employed by Pacific Power in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions and trading. From 1997 through 2000 I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. Since my return to Portland, I have been involved in direct access issues in Oregon and have been responsible for directing the analytical effort for the Multi-State Process ("MSP").

Q. Have you previously testified in state regulatory proceedings?

A. Yes. I have testified in California, Idaho, Montana, Oregon, Utah, Washington and Wyoming on net power costs, customer class cost of service, avoided costs and direct access. I also sponsored testimony in the Company's Structural Realignment Proposal ("SRP") application.

Purpose

Q. What is the purpose of your direct testimony in these proceedings?

A. First, my direct testimony provides background information on PacifiCorp's system operations and associated modeling tools. Next, my direct testimony describes the "Dynamic" and "Hybrid" proposals and summarizes key analytical findings with respect to them. Finally, my direct testimony provides further explanation of certain provisions of the PacifiCorp Inter-Jurisdictional Cost Allocation Protocol ("Protocol") sponsored by Ms. Kelly that relate to system operations. In the interest of clarity and consistency, when I use a capitalized term in my testimony, and do not otherwise define it, I intend the term to have the same meaning as provided for in Appendix A to the Protocol.

The PacifiCorp System

Q. What is the relevance of PacifiCorp's system operations to inter-jurisdictional cost allocation issues?

A. Most Multi-State Process ("MSP") participants believe that cost allocations should reflect principles of cost causation. This is a relatively easy principle to follow for the assignment of distribution costs associated with local delivery of power to individual customers, but becomes more complex when it comes to transmission and generation costs. The local distribution costs in any State are only dependent on the customers in that State. Transmission and Generation costs, however, are costs incurred to produce and move bulk power to the local points of distribution across PacifiCorp's entire system. The Company has 1.5 million customers spread across six States covering over 135,000 square mines. The Company's supply portfolio consists of 8,200 megawatts of generating capacity from over 70 generating facilities located across eight states as well as many wholesale purchased power contracts with other utilities. The Company owns 15,000 miles of transmission lines, has over 125 points of interconnection with other utilities and has many wheeling contracts that in combination are used to transport the power produced at the various facilities to the loads across the system. The Company is limited by transmission constraints and operates its system on an integrated basis with two control areas. In the real world of PacifiCorp's six-state integrated system, cost allocation issues for generation and transmission costs are far more complicated than distribution costs and potentially contentious because the system has some attributes of a single system serving six states and some attributes of two separate systems serving different regions.

Q. Please describe how PacifiCorp operates its power system.

A. The Company dispatches its power system to minimize total Company costs on a six-state integrated basis. The operation is separated into two control areas. The East Control Area includes the Idaho, Utah and Wyoming loads and includes generating resources such as Hunter, Huntington, Naughton, Gadsby, Dave Johnston, Cholla and Wyodak. The West Control Area includes the California, Oregon and Washington loads and includes generating resources such as the Hydro-Electric Resources, Hermiston, Colstrip, and Jim Bridger as well the Bonneville Peak Purchase contract and the Mid-Columbia Hydro Contracts.

Q. What are the primary responsibilities of a control area operator?

A. Each control area operator is responsible for ensuring that reliable service is provided to the control area loads in accordance with the National Electricity Reliability Council ("NERC") Minimum Operating Reliability Code. This is accomplished by making sure that adequate spinning and non-spinning reserves are available for unplanned generator outages and that adequate regulating margin is available to ensure that the system frequency remains steady as loads increase and decrease on an instantaneous, real-time basis.

Q. Why does PacifiCorp operate two control areas instead of one?

A. The Company does not have sufficient transmission rights between its West and East Control Areas to operate as a single control area. A control area requires the ability to change schedules instantaneously in order to comply with the NERC standards. The Company has some capability to integrate its two control areas, but not enough to meet the NERC criteria.

Q. How does PacifiCorp model the transfer capability between its two control areas?

A. Exhibit No. 4 shows the transmission topology used in the Generation and Regulation Initiatives Decision Tools ("GRID") model. The "bubbles" labeled 'DSW', 'East Main', and 'Wyoming' are in the East Control Area, while those labeled 'Jim Bridger', 'Idaho', 'West Main', 'COB', and 'Mid Columbia' are in the West Control Area. The transfer capability modeled from the east to the west is 596 megawatts from November through April and 558 megawatts from May through October. This consists of 400 megawatts from Wyoming to Jim Bridger, 104 megawatts from East Main to Jim Bridger, and 92 megawatts in the winter and 54 megawatts in the summer from East Main to Mid Columbia. The transfer capability modeled from the west to the east is 1071 megawatts from November through April and 1033 megawatts from May through October. This consists of 500 megawatts from Jim Bridger to Wyoming, 479 megawatts from Idaho to East

Main and 92 megawatts in the winter and 54 megawatts in the summer from Mid Columbia to East Main. In addition, 75 megawatts of transfer capability is reserved from west to east for non-spinning reserves and 100 megawatts is reserved in both directions for spinning reserves.

Q. How does the Company use its transfer capability between control areas?

A. Depending upon the load requirements, Resource availability and market prices in each control area, the Company is able to transfer power from east to west or west to east to minimize total system costs in each hour.

Q. Can the Company rely upon non-firm wheeling to operate as a single control area?

A. No. The use of non-firm transmission would not satisfy the NERC reliability criteria.

Q. Does the Company use non-firm transmission to augment the integration of its control areas?

A. Yes. The Company is able to purchase non-firm transmission on an as, if and when needed basis to enhance system integration. Historically, this has represented about 200 average megawatts of transfer capability in excess of the Company's firm transmission rights. This allows the Company to use Resources in one control area to help meet the loads in the other control area.

Q. Does the Company expect to maintain two control areas upon participation in an RTO?

A. No. An RTO would consolidate control areas in order to provide for system operation efficiencies, reliability benefits, improved planning and decision-making on system expansion and to provide "one stop shopping" for transmission services. The Company's East and West Control Areas, along with those of several other utilities, are expected to be consolidated into the same control area upon participation in an RTO.

Q. Can a Resource added in one control area provide benefits to customers located in the other control area?

A. Yes. The Company's control areas are not entirely separate and there are several ways that resources added in one control area can provide benefits to customers located in the other control area. PacifiCorp will continue to plan and operate its generation and transmission on a six-state integrated basis in a manner that minimizes costs to all its retail customers. This allows the Company to locate a power plant in one control area to meet load requirements in the other control area if that is the least-cost, least-risk option for the total system. In addition, the Company has entered into three cross-control area Exchange Contracts that allow power to be delivered in one control area and returned in the other, effectively transferring power without requiring transmission. The degree to which resources in one control area can impact the other control area is shown in the analyses of the impacts of load loss, discussed later in my testimony in the section titled, "2003 MSP Analyses."

Net Power Costs

Q. What are Net Power Costs?

A. Net Power Costs are the sum of: a) the Company's variable generation costs (mostly fuel) b) costs under purchased power contracts and c) wheeling costs, less revenues received under power sales contracts.

Q. How does the Company compute Net Power Costs?

A. The Company computes Net Power Costs using the GRID model. This model was developed by PacifiCorp to simulate the hourly operations of its power and transmission system. GRID calculations reflect all of the Company's generating facilities and power contracts based upon their individual attributes. Operation of the Company's system is limited by transmission constraints. These constraints are also reflected in GRID. The Company has used the GRID model as the basis for computing Net Power Costs in rate cases filed since December 2001. The GRID model is more realistic than previous models of Net Power Costs because it simulates system operation on an hourly basis, substantially reflecting the way the system is actually operated.

2002 MSP Analyses

Q. Please describe the MSP analytical process during 2002.

A. Beginning in March 2002, the Company organized a Modeling Workgroup of MSP participants. The group received briefings on analytical methods and issues. The Company made available copies of the GRID model, together with computers capable of running it, to key groups in each State. Members of the workgroup were invited to suggest analytical studies that could be run either by the Company or by other participants.

The analytical workgroup met either by phone or in person 28 times during 2002. The workgroup discussed studies to be run, specific analytical issues, and the results of completed studies.

Q. What studies were considered by the workgroup?

A. The Company compiled a list of 56 studies which were proposed for consideration by the workgroup. Each study was intended to help evaluate the impact on revenue requirements in each State of specific changes in allocation methodology. As I indicated previously, the GRID model computes Net Power Costs on a total system basis. In order to calculate individual State impacts, the results of each GRID study were used as input into the Revenue Forecasting Model ("RFM"). Most studies were run for the 15-year period beginning with fiscal year 2004. The input data used in the first studies was updated four times to incorporate more recent information. The final set of data largely incorporates the results of the Company's 2003 Integrated Resource Plan along with hydro relicensing and clean air costs. Some studies were proposed, but not completed, either because the sponsor withdrew the request or replaced a requested study with another.

The 2002 studies identified and evaluated many issues and laid the foundation for the "MSP Solution". Studies MSP-1 (Rolled-in) and MSP-2 (Modified Accord) became the standards of comparison and were updated as the input data were updated. These studies allowed each MSP participant to assess the revenue requirement impact that different changes would have on their individual State. Studies MSP-8 through MSP-15 began the evaluation of directly assigning Resources to individual States and therefore introducing the concept of interchange and transfer pricing. This concept was eventually refined in Study MSP-47, which produced revenue requirement results using the Hybrid Proposal, which I describe later in my testimony. Studies MSP-16 and MSP-17 analyzed situs assignment of peaking and hydroelectric Resources, respectively. Studies MSP-31, 33 and 35 evaluated the inclusion of a hydro endowment in a dynamic framework. These studies also introduced the concept of monthly weighting of costs for Resources principally acquired for use during a particular season of the year. Both of these concepts have been incorporated in the "MSP Solution". In addition, hourly allocation factors were examined in this series of studies along with the appropriateness of the situs assignment of Demand Side Management costs and the need for a wholesale jurisdiction. The use of hourly allocation factors did not prove to provide sufficient benefit over the use of monthly factors to take on the added complexity of working with hourly data. The studies on Demand Side Management resulted in validating that the current situs assignment method was still appropriate. Studies MSP-44 through 52 examined separation of States either physically or on an accounting basis. Studies MSP-47 (Hybrid), MSP-50 (Control Area Stand Alone) and MSP-51 (Divisional Stand Alone) were presented in the July, 2003 meeting with all MSP participants.

The Dynamic and Hybrid Proposals

Q. The last MSP meeting of 2002 occurred in December. What were the results of that meeting?

A. The group identified two possible allocation methods: the Dynamic Proposal and the Hybrid Proposal. Under both methods, the Company would continue to operate its system on an integrated basis. Both methods were seen as "accounting solutions" that would pertain only to ratemaking. Nonetheless, the two methods represented quite different approaches. The Dynamic Proposal generally allocated a proportionate slice of all system wide costs and revenues to each State, while the Hybrid Proposal assigned costs and revenues by control area with hourly accounting for transfers between control areas. Neither of these methods commanded a consensus of participants. Participants agreed that the Company should further analyze and develop the two proposals in consultation with other participants. Conclusions were to be presented at a future MSP meeting.

Following the meeting, the Company conferred with MSP participants and performed the requested analyses. The results were discussed at an MSP meeting in July 2003.

Q. Please summarize the Dynamic Proposal.

A. The core Dynamic Proposal is the "rolled-in" allocation method currently used in Utah. Under this method, all States would pay shares of the Company's costs that are based upon the State's shares of total system demand, energy, and other factors. Cost shares would change over time as States grow at different rates and the characteristics of their loads change. Net Power Costs would be allocated based upon each State's requirement for system capacity and energy. Costs of generation Resources would be classified as 75 percent Demand/25 percent Energy-Related and allocated based upon the 12 CP Factor in the same manner proposed for System Resources under the MSP Solution as described by Mr. Taylor. Under the Dynamic Proposal, the allocation of Resource costs would be the same for all generation, existing and new, regardless of location.

Q. What were the principal concerns raised by MSP participants regarding the Dynamic Proposal?

A. Some participants, primarily from the states of Oregon and Washington, expressed concerns that using the Dynamic Proposal would cause customers in their States to pay additional costs associated with new Resources acquired to serve rapidly growing loads in the State of Utah. Participants, again primarily from the States of Oregon and Washington, expressed a belief that their States were entitled to a greater share of the benefits of the Company's Hydroelectric Resources than would be provided under the Dynamic Proposal. There was also evidence that the Dynamic proposal would not accommodate differing State policies and perspectives regarding the types of new Resources to be developed. The Company was also concerned that the Dynamic Proposal would not be sufficiently durable to resolve allocation issues during the years to come because of differing State policies and perspectives such as those related to new Resources additions and Direct Access Programs.

Q. Please summarize the Hybrid Proposal.

A. The Hybrid Proposal would separate PacifiCorp's system, for purposes of cost allocation, into two regions. Loads in the states of Oregon, Washington and California would be associated with the West Region. Loads in the states of Idaho, Utah and Wyoming area would be associated with the East Region. Generating Resources and Wholesale Contracts would be assigned based on present control area location, largely reflecting the way that the Company's system is operated. The overwhelming majority of hydroelectric Resources are located in the West Control Area and would be assigned to the West Region. New Resources would be assigned to a particular region based upon location and would be substantively reviewed only by Commissions in the affected region. Although the Company would continue to operate its system on an integrated basis, customers in the two regions would be deemed to be served from different Resource pools. Consequently, for ratemaking purposes, one region may be deemed to be "short" (having fewer Resources than needed to serve load) in an hour during which the other region is "long". To deal with this issue, the Hybrid Proposal includes an "interchange accounting" method which would compensate a long region if its Resources were deemed to have been relied upon by the other region.

Q. What were the principal concerns raised by MSP participants regarding the Hybrid Proposal?

A. Many parties expressed concerns and disagreements regarding the initial assignment of Resources to the regions. Even proponents of the Hybrid proposal could not agree on an appropriate initial Resource assignment. Some parties advocated assignment of some Resources in ways that were inconsistent with the control area approach, based upon claims of historic "ownership". Some participants, primarily from Utah, expressed concerns that the Hybrid Proposal would lead the Company away from integrated least-cost system planning. They expressed concerns that the Hybrid Proposal would increase risks because it reduces the diversity of fuel types used to serve each region. They also expressed concerns that the interchange accounting method would complicate the regulatory process and become unworkable.

2003 MSP Analyses

Q. What were the results of the Company's analysis of the Hybrid and Dynamic Proposals?

A. The impact of the Hybrid Proposal on overall revenue requirements is shown in Exhibit No. 5. The overall impact is quite modest. On a present value basis, all States see small increases in revenue requirements as the existing allocation "hole" is closed. Each State's costs increase by less than one percent. All States see increases in some years and decreases in others.

Q. Did the Company analyze the risks associated with the Hybrid Proposal?

A. Yes. The Company's risk analyses are described in Exhibit No. 6. The analyses were intended to highlight situations in which customers in specific States might face different risks under the Dynamic Proposal than under the Hybrid Proposal. The analyses considered ten scenarios. The scenarios include two that studied the impact of temporary, unexpected losses of load: one in the East Region and one in the West. Four of the scenarios studied risks associated with Resources. Of these, one scenario altered assumptions regarding new Resource additions in response to changes in load forecasts since the development of the Company's 2002 Integrated Resource Plan. Two of the Resource scenarios looked at the impacts of low and high water conditions combined with high and low market prices, respectively. The fourth considered the loss, for one year, of a major coalfired generating Resource in the East Control Area. This last scenario also assumed that natural gas and market prices were high at the time of the loss.

The remaining four analyses studied risks associated with market prices. Of these, two assumed that wholesale market price trends (both natural gas and electric) were higher or lower than expected. Another looked at the impact of a year in which market prices in the West Region were higher, relative to the East Region, than were assumed in the base analysis. The last risk scenario studied the reverse of this situation, with East market prices rising relative to the West.

Q. What did the Company conclude from its analyses of generation risks?

A. The generation sensitivity studies show greater risk under the Hybrid Proposal than under the Dynamic Proposal. High water conditions, for example, reduce costs for the Company as a whole. Under the Dynamic Proposal, these cost reductions are shared equally among all States. Under the Hybrid Proposal, cost reductions are experienced only by States in the West Region. Patterns associated with generation loss in the East Region were even more striking. The Dynamic Proposal results in similar cost increases for all States. The Hybrid Proposal leads to much greater cost increases in the East Region, nearly three times as great when measured against the Dynamic Proposal on a dollars-per-megawatt-hour basis. The Hybrid Proposal actually leads to cost decreases in the West Region, due to increased revenue from off-system sales and interchange accounting.

Q. What did the Company conclude from its analysis of market price risks?

A. Studies of market price risk also showed greater risks under the Hybrid Proposal than under the Dynamic Proposal. Low market prices decrease costs for the

Company as a whole. This was true in eight of the ten years that the Company analyzed. The opposite is true under high market prices. Net Power Costs increase with higher market prices when the Company buys more from the market than it sells. The only two years this was not true, 2008 and 2009, followed the addition of two major baseload plants on the system, creating a short-term surplus of power which resulted in lower power costs for the Company when market prices increased. Under the Dynamic Proposal, these cost increases and decreases are shared among the States in proportion to their retail loads. Under the Hybrid Proposal, States in the West Region experience a cost increase when total system costs decreased and received a cost decrease when total system costs increased. This pattern reflects the differences in the initial assignment of Resources as well as different load and Resource balances in each control area over the ten-year study time frame. The West control area benefits with high market prices since it is generally surplus in relationship to the East control area in the Hybrid analyses and therefore receives more revenue credit from system balancing sales and interchange accounting.

Consequences of Load Growth

Q. One of the concerns expressed during the MSP is that not all States are growing at the same rate. Is this the case?

A. Yes. Exhibit No. 7 shows the change in both energy consumption and contribution to system peak over the last 10 years. As can be seen, Utah's load growth has been significantly higher than that of the other States. The Company's current load forecast expects this trend to continue.

Q. You testified that the MSP Solution allocates costs dynamically and, with the exceptions described in the Protocol, all States share in the cost of new Resources. Does this provision cause slow-growing States to subsidize fast-growing States?

A. Not to a material degree. The Company reached this conclusion based on three analyses: an analysis of a specific new Resource addition, an examination of the impact of the Hybrid and Dynamic proposals, and the analysis of load risks conducted on the Hybrid and Dynamic Proposals. These studies indicate that the Dynamic Proposal limits, to a surprising degree, the impacts of load growth across states. On balance, a dynamic allocation limits the impacts of faster Utah load growth as well as the Hybrid Proposal.

Q. Please describe the Company's specific analysis of the impact of Utah load growth under the Dynamic Proposal.

A. In this study, Utah's loads were increased an additional 200 megawatts above the MSP forecast starting in 2010. Concurrently, a 200 megawatt combined-cycle gas plant was assumed to be added to meet the additional load. Mr. Taylor's Exhibit No. 7 shows the revenue requirement impacts of these two changes. Utah is allocated 94 percent of the total revenue requirement increase. The other States experience some impact, but the impact is minimal.

Q. Why aren't more of the costs of the additional Resource passed on to other States?

A. While all States pick up their proportional share of the higher than system average costs of the new additional Resource, Utah, the faster growing State in this example, picks up a larger share of all other allocated costs. As a result of its now larger allocation factors, Utah picks up a larger share of the costs of the remaining generation Resources, a larger share of the system's transmission costs, a larger share of A&G expenses and all other allocated costs.

Q. What do the overall analyses of the Hybrid and Dynamic Proposals indicate regarding the impact of load growth?

A. The Hybrid proposal largely insulates the States in the West Region from the impact of load growth in Utah while the Dynamic Proposal melds the two Regions together. If Utah load growth is a burden to Oregon, Washington and California, one would expect that the Western States' costs would increase at a slower rate if the States were separated using the Hybrid Proposal.

Q. Does this occur?

A. No. Although the initial costs of Oregon, Washington and California are lower under the Hybrid Proposal, this is entirely a product of the initial assignment of Resources between the two regions and has nothing to do with how either the Dynamic or Hybrid Proposals operate. Setting aside initial cost levels, Oregon, Washington and California costs grow at a *faster* rate from 2004 under the Hybrid Proposal where they are "insulated" from Utah load growth. This effect is shown in Exhibit No. 8. This result, together with other analyses, caused the Company to conclude that the Dynamic allocation does not result in a material unfair subsidy to Utah from customers in the western States. Furthermore, any subsidy that might exist under a "pure" Dynamic Proposal would be further mitigated by the Company's proposed treatment of Seasonal Resources under the MSP Solution.

Q. Why would generation costs increase faster in the West under the Hybrid Proposal than under the Dynamic Proposal?

A. There are two reasons. First, the embedded cost of existing resources in the West are forecast to exceed those in the East on a dollar per megawatt-hour basis. Under the Hybrid Proposal, the East does not pay for any of these higher cost Resources in the West and the West bears all of these costs. Under the Dynamic Proposal, all States pay for a share of existing Resources at a system average cost, which helps to reduce the cost to the West. Second, States in the West Control Area have resource needs of their own. While underlying retail loads are not increasing as quickly, the West Control Area is served by a number of long-term Wholesale Contracts which are expiring. Exhibit No. 9 shows the effective need for new Resources by control area, including the need to replace expiring contracts. It shows that by 2018, about 35 percent of the East Control Area loads and about 30 percent of the West Control Area loads need to be served by new Resource additions. This suggests that the impact of the cost of new Resources on the West is not much different under the Hybrid or Dynamic Proposals.

Q. Is this consistent with resource additions identified in the Company's 2003 Integrated Resource Plan?

A. Yes. Table 7.3 entitled "East-West Cost Breakdown", shows that both the present value of the Revenue Requirement ("PVRR") and the capacity additions under the

Diversified Portfolio I are close to 60 percent East and 40 percent West, which tracks closely with relative loads between the two control areas.

Q. You indicated earlier that the Company conducted a risk analysis that studied the impact of a loss of load in each Control Area. What did the Company conclude from this analysis?

A. In response to a one-year loss of load, allocated costs under the Hybrid Proposal respond very similarly to allocated costs under the Dynamic Proposal. The results are shown in Exhibit No. 6. As measured on a dollars per megawatt hour basis, a loss of load in one State increases costs in that State by an amount that is very similar between the two proposals. Interestingly, a loss of load in one State has almost no impact on costs in other States under either proposal.

Q. Would you expect this same pattern if loads increased?

A. Yes. Based on this study, I would expect an increase in loads in one State to reduce costs per megawatt hour in the affected State and have little effect on remaining States.

Q. Are there additional conclusions that can be drawn from this risk analysis?

A. Yes. The Company examined the response of individual generating resources predicted by GRID as a result of the loss of load. The results, presented in Exhibit No. 10, show clearly that the two Control Areas work together to meet changing loads. In response to load loss in the East Control Area, Company generating resources reduced their output by 162 average megawatts. Of that reduction, nearly half, 46 percent occurred at Resources in the West Control Area. A similar shared response occurs in response to load loss in the West Control

Area. The Control Areas are not totally isolated from one another. This implies two conclusions. First, there is no operational reason to assume that resources added in the East Control Area have no benefit to the West Control Area. Second, even the Hybrid Proposal would not be sufficient to entirely insulate a state in one Control Area from developments in another Control Area, because the operation of the system links the two.

Protocol Provisions

Hydro and Coal Endowments

Q. **Ms. Kelly's direct testimony indicates that the MSP Solution contemplates a Hydro-Endowment for the former Pacific Power jurisdictions. Does the "Modified Accord" allocation method that has been relied upon by some States also include a hydro endowment?**

A. Yes.

Q. **Does the Hydro-Endowment proposed in the MSP Solution differ from the hydro-endowment under Modified Accord?**

A. Yes, it differs in three respects. First, the Hydro-Endowment in the MSP solution includes not only the Company's owned generating facilities, but also hydro-based contracts with Mid-Columbia utilities. Second, the Hydro-Endowment under the MSP Solution operates in a different way. Under Modified Accord, Northwest states receive a credit to their allocation of fuel costs, but all States support the Fixed Costs of Hydro-Electric Resources. This method of implementing the hydro endowment is suggested by the fact that Hydro-Electric Resources do not incur fuel costs. The MSP Solution would assign all costs of

Hydro-Electric Resources to Hydro Endowment Participants Third, the Hydro-Endowment under the MSP Solution is coupled with a Coal Endowment to the former Utah Power jurisdictions.

Q. Please explain the Coal Endowment.

A. The Coal Endowment under the MSP Solution allocates the costs of the Huntington Resource, including associated mine costs, to customers in Utah, Idaho and western Wyoming. By including the Coal-Endowment, all jurisdictions receive a roughly equal assignment of pre-merger resources on both a capacity and energy basis.

Q. Why is a Coal-Endowment appropriate?

A. The direct assignment of Hydro-Electric Resource costs to the Hydro-Endowment Participants requires an economic offset in order to avoid unreasonable cost shifts. This can be done by assigning a like amount of pre-merger resources to the States that are not Hydro-Endowment Participants, such as a Coal Endowment, or by decreasing the assignment of all other resources to the Hydro-Endowment Participants. This latter method has traditionally been referred to as the 'load decrement' approach. The Company has elected to propose using a Coal Endowment rather that a load decrement in the MSP Solution. A primary difference between the methods is how the cost of new Resources are allocated among the States. If there were only a Hydro-Endowment, then the Hydro-Endowment Participants would pay a smaller share of the cost of new resources if they had a load decrement. Using a Coal Endowment of equal size eliminates the need to decrement the loads of any State and results in a pro-rata sharing of new resource costs based on the requirements that each State places on the system.

Q. **Have any prior allocation methods directly assigned costs to the former Pacific Power and Utah Power Divisions in a manner similar to that proposed in the MSP Solution?**

A. Yes. All of the allocation methods since the merger of Utah Power and Pacific Power, except the Rolled-In method, have directly assigned some amount of pre-merger plant to each Division.

Q. **Why does the Company propose this form of Hydro-Endowment rather than the form used in the Modified Accord allocation method?**

A. The Company proposes this method for two primary reasons. First, the Modified Accord approach is only applicable to Company-owned hydroelectric Resources. Second, the proposed method clearly assigns all costs of Hydroelectric Resources to Participating States. The Company expects to incur substantial capital and operating costs as it relicenses its hydroelectric facilities and expects that relicensing will also increase its costs under the Mid-Columbia contracts. The Modified Accord method does not properly link those costs to the associated benefits.

Q. **You indicated that the mid-Columbia contracts would be treated, under the MSP Solution, as part of the Hydro-Endowment. What specific contracts would be included?**

A. There are four mid-Columbia contracts: one with Chelan County Public Utility District related to the output of Rocky Reach Dam which expires October 31, 2011; one with Douglas County Public Utility District related to the output of Wells Dam which expires August 31, 2018; and two with Grant County Public Utility District, one of which relates to the Priest Rapids Dam and one to Wanapum Dam. These last two projects expire on October 31, 2005 and October 31, 2009, respectively.

Q. What would occur when these contracts expire?

A. Each contract provides the Company with certain rights regarding successor contracts. The Company expects to negotiate extensions to these contracts or negotiate successor contracts. This has already occurred with respect to the Grant County contracts. Costs and benefits associated with extensions to the mid-Columbia contracts or successor contracts would be allocated as part of the Hydro Endowment like the original contracts. The terms of the successor contracts for the Priest Rapids, Wanapum and Rocky Reach projects are included in the Company's analyses.

Seasonal Resources

Q. Ms. Kelly's direct testimony also states that under the MSP Solution, some Resources will be treated as Seasonal Resources. How will the Company identify Seasonal Resources for purposes of this allocation process?

A. Three categories of "Seasonal Resources" are defined in the Protocol and are based on long-term commitments for Resources that were primarily intended to provide power to the Company during the summer or winter seasons.

Q. What Resources would presently be considered Seasonal Resources under this definition?

A. The Company owns or leases eight Simple-Cycle Combustion Turbines -- three at the Gadsby site and five at West Valley. Costs of these facilities would be allocated as Seasonal Resources. In addition, the Company has entered into three long-term contracts that would be considered Seasonal Resources and a fourth contract is included as a resource in the IRP. These contracts are described in Exhibit No. 11. Finally, as indicated by Ms. Kelly, the MSP Solution would treat the Cholla Unit IV and the associated Exchange Contract as a Seasonal Resource.

Q. Mr. Taylor's direct testimony indicates that the allocation factors for Seasonal Resources use monthly factors that are weighted by the monthly portion of the total annual energy generated by the Seasonal Resource. On what basis are these energy values determined?

A. Seasonal Resources are primarily acquired to meet the Company's retail load; however, the GRID model will run Seasonal Resources to make wholesale sales if it reduces the overall system Net Power Costs. To isolate the operation of Seasonal Resources for meeting retail loads, a separate GRID run is made in which no incremental hourly sales are made in the wholesale markets. The monthly and annual energy values are taken from this study and provided to Mr. Taylor for purposes of calculating allocation factors for Seasonal Resources.

First Major New Coal Resource

Q. Has the Company analyzed how each State would be affected if Oregon exercised the option to not participate in the First Major New Coal Resource?

A. No. All of the analyses implicitly assume that Oregon participates in the First Major New Coal Resource. If Oregon were to exercise its option not to participate in the First Major New Coal Resource, it would be based on analyses that incorporated the views of Oregon on future costs of natural gas and carbon dioxide emissions and the analyses would show benefits to the State of Oregon. At the same time, different assumptions about natural gas and carbon dioxide emission costs could produce analyses that show benefits to all of the other States. Based on the different views of these costs among the States, the Company has only qualitatively addressed this issue.

Q. Does this conclude your Direct Testimony?

A. Yes.